Draft decision

N.T. Gas

Access arrangement proposal for the Amadeus Gas Pipeline

1 July 2011 – 30 June 2016

April 2011

Request for submissions

This document sets out the Australian Energy Regulator's (AER) draft decision for access arrangement proposal from N.T. Gas Pty Limited ACN 050 221 415 (NT Gas) as a trustee of the Amadeus Gas Trust owners of the Amadeus Gas Pipeline (AGP) for the period 1 July 2011 to 30 June 2016.

NT Gas must submit a revised access arrangement revision proposal responding to the AER's draft decision by 27 May 2011.

Interested parties are invited to make written submissions on issues regarding the draft decision and the consultants' reports to the AER by 24 June 2011. The AER will consider all information it receives in the access arrangement review process, including submissions on the draft decision.

Submissions can be sent electronically to **Amadeusgasreview@aer.gov.au.**

Alternatively, submissions can be mailed to:

Warwick Anderson
General Manager – Network Regulation
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601.

The AER prefers that all submissions be made public to facilitate an informed and transparent consultative process. Submissions should be made with reference to the AER's Access arrangement guideline (AAG) and the ACCC–AER information policy: the collection, use and disclosure of information (ACCC–AER Information Policy).[1] These documents are available at www.aer.gov.au. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to submit this information as outlined in the AAG.

All non-confidential submissions will be placed on the AER's website.

Copies of the access arrangement proposal for the AGP, relevant consultant reports and other relevant material are available on the AER's website.

Inquiries about this draft decision or how to make submissions can be made by email to **Amadeusgasreview@aer.gov.au** or by phone on (02) 6243 1233.

1 ACCC and AER, *ACCC–AER information policy: the collection, use and disclosure of information*, 23 October 2008.

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The AER does not propose to approve N.T. Gas Pty Limited's access arrangement proposal for the Amadeus Gas Pipeline as it is not satisfied that it meets the National Gas Rules' requirements.[2] The draft decision sets out the detailed reasons for this decision.[3]

This decision also outlines the amendments (or nature of amendments)[4] required to be made to the access arrangement proposal[5] or the access arrangement information[6] for the AER to approve the access arrangement proposal.

Elements of the access arrangement proposal that do not require amendment are consistent with the national gas objective.[7]

2 NGR, r. 41 and r. 100.

3 NGR, r. 59(4).

4 NGR, r. 43(3) and r. 59(2).

5 N.T. Gas Pty. Limited, *Access arrangement for the Amadeus Gas Pipeline–01 July 2011 to 30 June 2016*, December 2010, (NT Gas *Access arrangement proposal*, December 2010).

6 N.T. Gas Pty. Limited, *Amadeus Gas Pipeline–Access arrangement information—Effective 1 July 2011–30 June 2016*, December 2010, p. 29 (NT Gas, *Access arrangement information*, December 2010).

7 NGR, r. 100.

Shortened forms

Shortened form	Extended form
ACCC	The Australian Competition and Consumer Commission
access arrangement information	N.T. Gas Pty Limited, *Access arrangement information*, 23 December 2010
access arrangement period	1 July 2011 to 30 June 2016
access arrangement proposal	N.T. Gas Pty Limited, *Access arrangement*, 23 December 2010
access arrangement submission	N.T. Gas Pty Limited, *Access arrangement revision proposal– submission*, 23 December 2010
AER	Australian Energy Regulator
AGP	Amadeus Gas Pipeline
CPI	consumer price index
Code	National Third Party Access Code for Natural Gas Pipeline Systems
earlier access arrangement	Access arrangement for 1 July 2001 to 30 June 2011 inclusive
earlier access arrangement period	1 July 2001 to 30 June 2011 inclusive
NT Gas	N.T. Gas Pty Limited
NGL	National Gas Law
NGR	National Gas Rules

Overview

Background

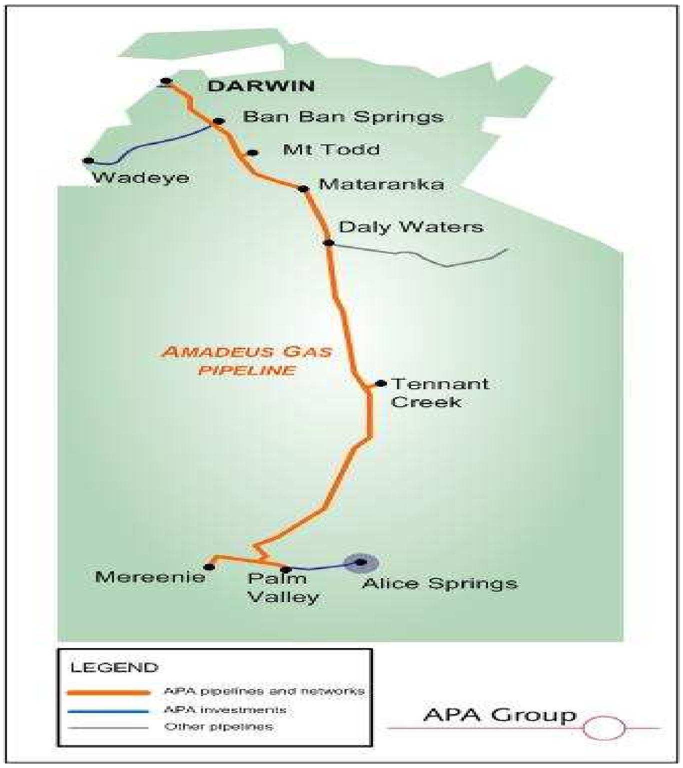
The AER is responsible for the economic regulation of covered natural gas distribution and transmission pipelines in all states and territories (except Western Australia). The AER's functions and powers are set out in the National Gas Law (NGL) and the National Gas Rules (NGR). The NGL and NGR came into effect on 1 July 2008. Prior to this, the National Third Party Access Code for Natural Gas Pipeline Systems provided the relevant regulatory framework for gas transmission pipelines.

On 23 December 2010, NT Gas submitted an access arrangement proposal for the Amadeus Gas Pipeline (AGP) for the period 1 July 2011 to 30 June 2016. In accordance with the NGR, the AER published NT Gas's access arrangement proposal on 14 January 2011. Interested parties were invited to make submissions on the proposal and four submissions were received.

Amadeus Gas Pipeline

The Amadeus Gas Pipeline (AGP) is a transmission pipeline in the Northern Territory that transports natural gas predominantly from the Blacktip gas field in the Bonaparte Basin which enters the AGP at Ban Ban Springs. Until 2012, gas is also contracted to enter the pipeline from the Mereenie gas field at the southern end of the pipeline. It is approximately 1658 kilometres in length, stretching from Palm Valley and Mereenie to Darwin in the north (see figure 1). NT Gas has only one user, Power and Water Corporation (PWC) which primarily uses the gas for gas-fired electricity generation. The network is a natural monopoly and is regulated by the AER to ensure that NT Gas does not charge excessive prices or impose unduly onerous terms and conditions on users.

Figure 1: Map of Northern Territory pipeline network



Source: APA viewed 20 January 2011, http://www.apa.com.au/media/150046/nt.jpg.

During the earlier access arrangement period all firm capacity on the pipeline was contracted to PWC.[8] At the time of the ACCC review of the earlier access arrangement, gas reserves in the Amadeus Basin were nearly depleted. The ACCC, therefore opted to apply an accelerated recovery of depreciation on pipeline assets through higher reference tariffs.[9] However, with the discovery and connection of the Blacktip gas field, gas flows on the pipeline have changed significantly, resulting in a much different operational context than what was anticipated at the time of the earlier access arrangement review.

Under the regulatory framework, NT Gas is required to submit a proposed access arrangement to the AER that sets out its proposed tariffs and terms and conditions. The AER then reviews the proposal and decides whether it is acceptable, or if amendments are required to make the proposal acceptable in accordance with the NGR and NGL.

NT Gas's proposal includes significant levels of capital expenditure (capex) on an enhanced integrity project beginning in the last year of the earlier access arrangement period. This is forecast to be completed in the first year of the access arrangement period. The enhanced integrity project is proposed to address safety risks and the deteriorating condition of the pipeline.

8 NT Gas, *Amadeus gas pipeline access arrangement revision proposal submission*, 23 December 2010 , p. 146.(NT Gas, *Access arrangement submission*, December 2010).

9 ACCC, *Final decision*, *Access arrangement proposed by NT Gas Pty Limited for the Amadeus Basin to Darwin Pipeline*,4 December 2002, p. 69 (ACCC, *Final decision–NT Gas*, December 2002).

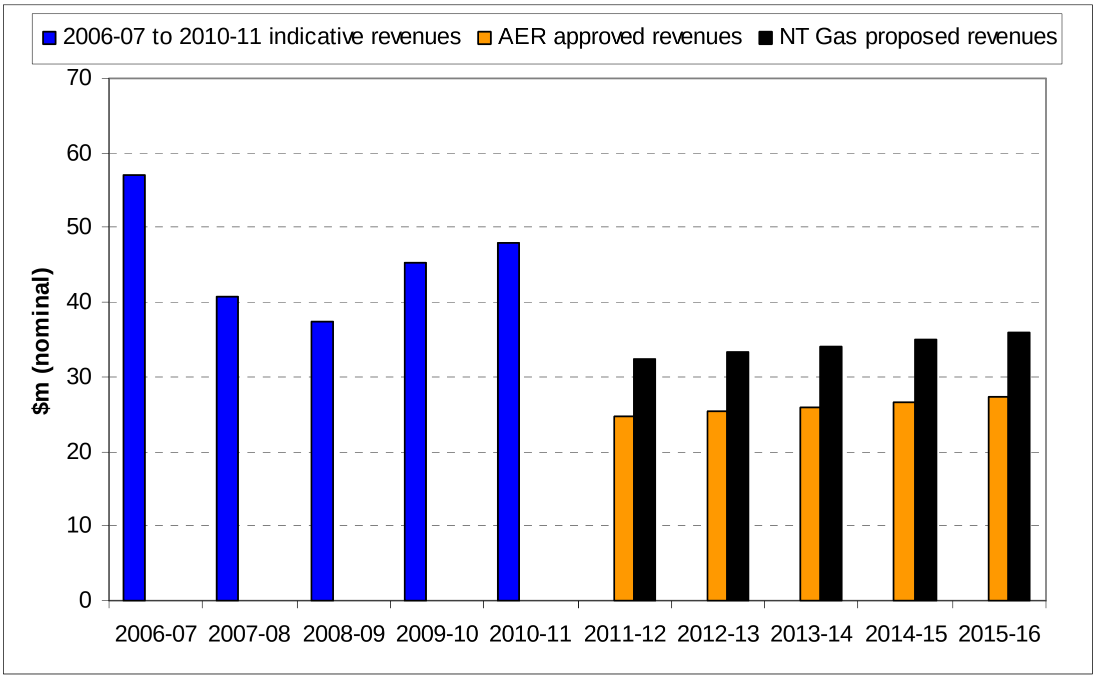
NT Gas has also proposed to change its tariff structure. Previously, the reference tariffs reflected the movement of gas from south to north. However, as gas is now being sourced largely from the north, NT Gas has proposed a single-zone tariff structure that reflects maximum daily usage irrespective of the location of gas deliveries.

Overall, the AER considers that NT Gas's access arrangement proposal is not acceptable because the proposed reference tariff is too high and the terms and conditions are too much in favour of NT Gas. As a result, the AER is requiring NT Gas to lower its proposed tariffs and amend its terms and conditions. However, the AER is of the view that some increase in tariffs is warranted so that NT Gas can provide a reliable and safe service. The main elements of the AER's draft decision are set out below. More detail can be found in the relevant chapters of the draft decision. The draft decision should be read in conjunction with NT Gas's access arrangement proposal and the AER's consultants' reports, which are available on the AER's website.

Total revenue

The AER calculates NT Gas's annual average revenue over the access arrangement period to be $26 million (nominal), a decrease of 39 per cent relative to the $42.3 million average annual revenues approved by the ACCC in earlier access arrangement period. This compares to NT Gas forecast average annual revenue of $34.1 million (nominal), a decrease of 21 per cent. The forecast revenue requirement is shown in figure 2, compared to the indicative revenues based on actual demand from the last five years of the earlier access arrangement period. Actual gas demand was around a third higher than forecast at last access arrangement review.

Figure 2: AER's revenues for NT Gas



Source: NT Gas, *Access arrangement submission*, December 2010, p. 142; AER analysis.

Note: Note that as the pipeline was previously near fully contracted to one user, NT Gas did not actually recover the reference service revenues as illustrated above. The indicative revenues pre-2011–12 were calculated using NT Gas's reference tariffs, adjusted backwards for actual CPI and multiplied by the actual gas throughput in the three zones.

In the earlier access arrangement period, NT Gas's asset base was depreciated rapidly, to address the risk of asset stranding on the pipeline. As a result of the new gas supply from the Blacktip gas field, the AER considers the stranding risk had been largely alleviated. The return to a more 'typical' depreciation profile was a significant driver of reductions in NT Gas's overall total revenue.

Proposed tariffs

The AER accepts NT Gas's proposal to change its tariff structure from a zonal tariff in the earlier access arrangement, to a single tariff for transport of gas between any receipt and delivery point on the pipeline. The AER considers that the single zone tariff structure would prevent significant step price increases in the southern and central sections of the pipeline, and therefore would limit the risk of the AGP being under-utilised. The AER also accepts NT Gas's proposal to shift from a volume based charge to a capacity tariff.

The tariff is calculated based on forecasts of capital and operating expenditure, the cost of capital, and depreciation expenses. Due to the AER's conclusions on these components of the draft decision, NT Gas's proposed base year reference tariff of $0.7596 per gigajoule (GJ) per day has been reduced by 24 per cent, to $0.5778 per GJ per day. Table 1 sets out NT Gas's proposed tariffs and the tariff calculated by the AER.

Table 1: NT Gas's proposed and AER's accepted reference tariffs (GJ)

	Zone	Tariff ($ 2011)
Earlier access arrangement (2010–11)	1	1.04
	2	0.74
	3	0.61
Proposed (2011–12)	single	0.7596[a]
AER accepted (2011–12)	single	0.5778[a]

Source: AER analysis
a: GJ of delivery point maximum daily quantity.

NT Gas has proposed a tariff that would be charged on the basis of capacity for the access arrangement period.[10] Over the earlier access arrangement period, tariffs were based on a user's gas throughput. This change, along with the reduced number of zones, prevents meaningful comparison of tariffs between the access arrangement periods.

10 NT Gas, *Access arrangement information*, December 2010, p. 29.

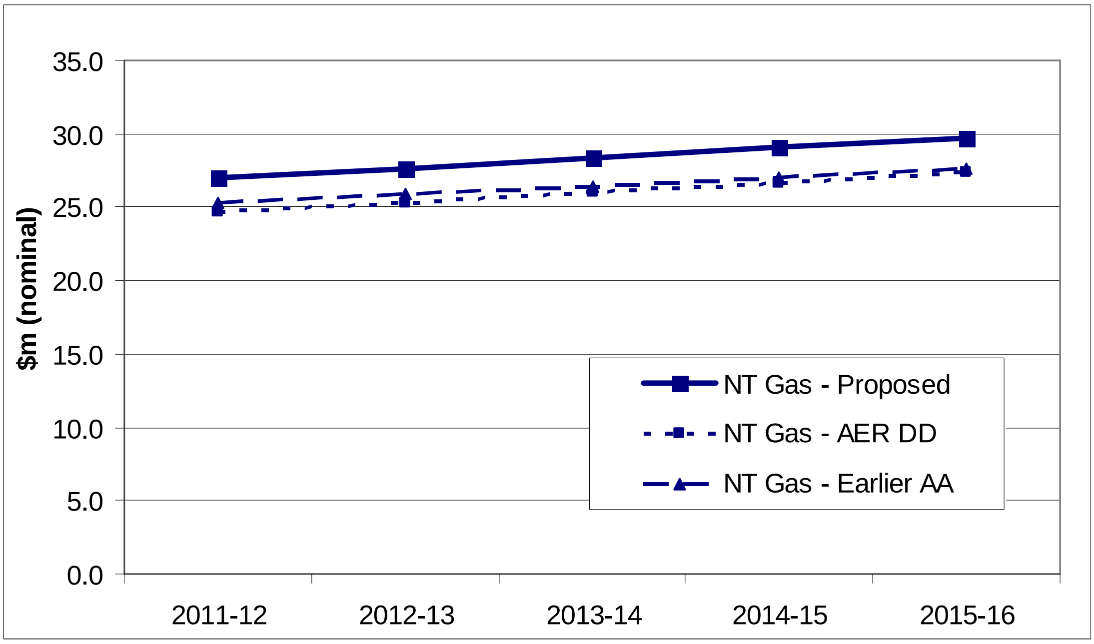
Cost of capital

The cost of capital, and resultant return on capital, are generally the most significant drivers of revenue for regulated businesses. However, due to the accelerated depreciation in the earlier access arrangement period, NT Gas has a small asset base relative to its total expenditure. The return on capital is therefore a smaller component of NT Gas's annual revenues than would normally be expected for a gas transmission business.

The higher cost of capital proposed by NT Gas (11.36 per cent, compared to 8.91 per cent for the earlier access arrangement period), would result in an 8 per cent increase in the estimated revenue requirement over the access arrangement period. The AER does not accept the cost of capital proposed by NT Gas and has instead estimated it to be 9.72 per cent. Compared to NT Gas's weighted average cost of capital (WACC) in the earlier access arrangement period, the approved increases in WACC are largely driven by a higher cost of debt. This estimate would account for an increase in the revenue requirement of 1 per cent over the access arrangement period. Figure 3 shows NT Gas's revenue in the access arrangement period under

a number of cost of capital scenarios. Further, table 2 sets out NT Gas's proposed WACC parameters compared to those approved by the AER.

Figure 3 NT Gas's forecast revenue under different cost of capital scenarios



Source: AER analysis.

Table 2: NT Gas's proposed and AER's allowed cost of capital parameters

Parameters	NT Gas proposal	AER draft decision
Nominal risk free rate	5.48	5.53
Inflation forecast	2.50	2.57
Real risk free rate	2.66	2.89
Cost of debt[11]	10.94	9.32
Debt risk premium	5.46	3.79
Cost of equity	11.98	10.33
Equity beta	1.00	0.8
Market risk premium	6.50	6.0
Gearing	60.00	60
Nominal cost of capital	11.36	9.72

Source: NT Gas, *Access arrangement submission*, December 2010, p. 115; AER analysis.

The AER considers that the parameters estimated by NT Gas do not meet the requirements of the NGR, and overstates the required rate of return.

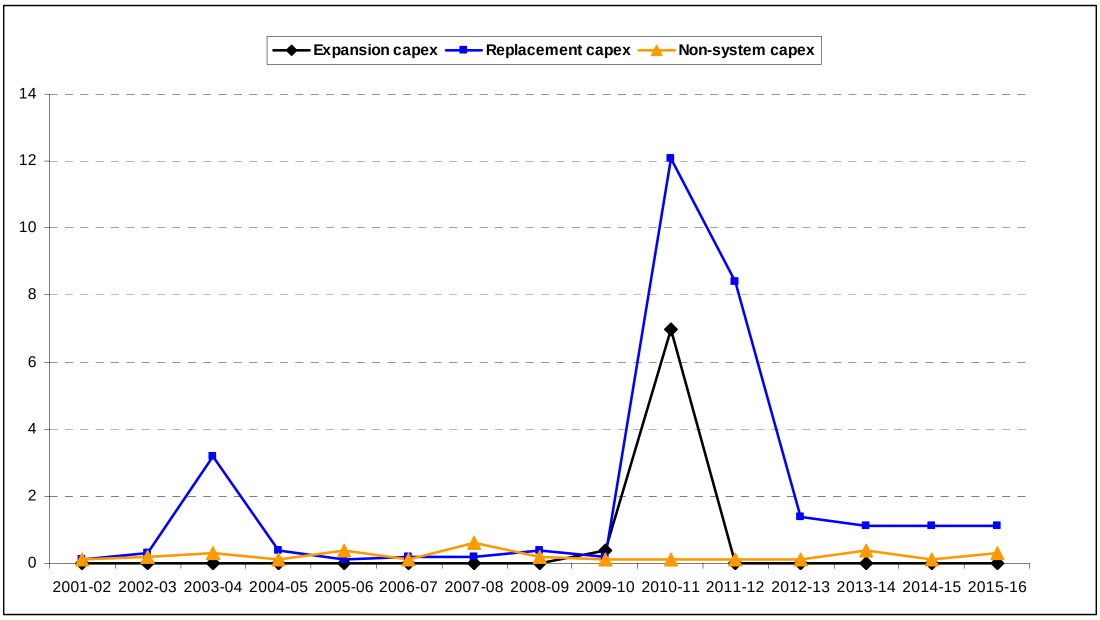
Capital expenditure

NT Gas has proposed forecast capex of $14.4 million over the access arrangement period.[12] Figure 4 sets out the major components of the forecast total expenditure are replacement (92.6 per cent) and non-system capex (7.4 per cent).

11 NT Gas proposed to include debt raising costs as a component in the cost of debt parameter. The AER has separated debt raising costs from the cost of capital as they do not directly reflect a required return to investors but are more akin to operating expenditure. The value in table 2 is the cost of debt without debt raising costs.

12 The earlier access arrangement period was a 10 year period compared to the access arrangement period which is set to be five years.

Figure 4: NT Gas's forecast capex by purpose – 2001–02 to 2015–16



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 81–83.

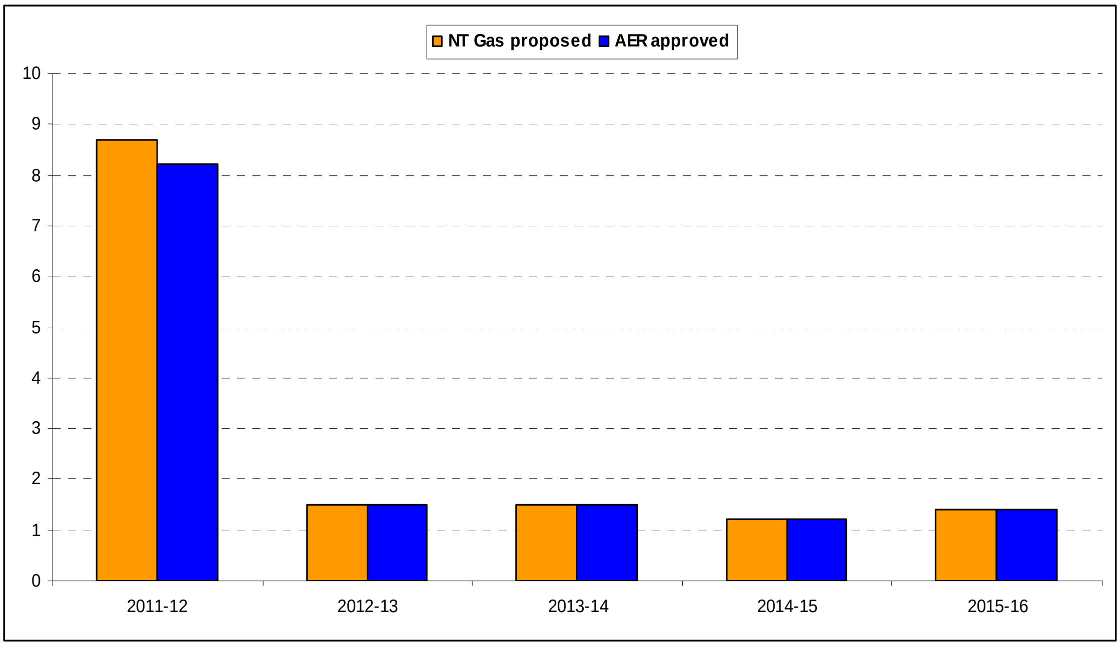
Enhanced integrity program

NT Gas has proposed to undertake an enhanced integrity capex program worth $22.4 million (nominal) over 2010–11 and 2011–12 in order to address integrity issues associated with the pipeline. This expenditure is justified, according to NT Gas, to rectify deteriorating pipelines, corrosion, metal loss and coating defects indentified through intelligent pigging.

In broad terms, the AER accepts the need for the replacement capex program, given the age of the pipeline and the evidence that it is expected to transport gas into the foreseeable future. However, the AER does not accept NT Gas's estimated costs for the replacement capex program in 2010–11. Instead, the AER has accepted significantly lower costs in 2010–11 that reflect the more up-to-date estimates of actual capex in 2010–11 provided by NT Gas.

For the access arrangement period, the AER largely accepts NT Gas's forecast capex. However, the AER does not accept forecast costs relating to project management fees and cost escalation, for which the AER considers better forecasts could be made. The AER accepts a forecast cost of $13.9 million ($2010–11) are justified under r. 79(2)(c) of the NGR to meet the needs of pipeline maintenance, integrity and safety of services. Figure 5 shows the forecasts accepted by the AER compared to those proposed by NT Gas in its access arrangement proposal.

Figure 5: NT Gas proposed forecast capex compared to AER draft decision



Source: NT Gas, *Access arrangement submission*, December 2010, p. 81, Email from NT Gas to AER, *AER.NTGAS.15*, 25 February 2011.

Other capital expenditure

The AER accepts the forecast non-systems and expansion capex proposed by NT Gas.

However, NT Gas included a [c-i-c][13] per cent project management fee for elements of its forecast capex. NT Gas has not provided any information to substantiate the inclusion of these costs. The AER does not accept the project management fee as it appears to be a double counting of overheads. Consequently, the AER has removed the project management fee from all forecast capital expenditure.

The AER also considers that the inflation rates used to roll forward the capital base was inconsistent with the tariff variation mechanism. After adjusting for these issues, the AER has calculated the capital base to be $99.5 million (nominal) on 1 July 2011. The AER identifies that NT Gas had not adjusted the nominal depreciation amount for the difference between actual and forecast inflation.

Operating expenditure

NT Gas has proposed a forecast opex of $71.1 million over the access arrangement period, representing an increase of 59 per cent over the earlier access arrangement period. According to NT Gas, the higher expenditure stems mostly from increases in overhead costs.

The AER does not consider NT Gas's forecast operating costs are prudent and efficient and the lowest sustainable cost of managing its network, as required by the NGR.

13 Refers to material that is commercial in confidence to NT Gas.

There is a large increase in proposed forecast overhead costs when compared with NT Gas's actual overhead costs incurred over the earlier access arrangement period. The AER considers that there is likely to be a substantial level of double counting between local and corporate overheads. This is because the AER considers that several corporate functions including accounting and engineering, which are normally undertaken by APA Group, are undertaken locally and are already included in overheads.

The AER has estimated real labour cost escalators that are lower than those forecast by NT Gas, based on its own analysis and advice from Deloitte Access Economics. The AER has also either amended or has not accepted a number of NT Gas's non base year costs on the basis that these are not consistent with the NGR.

Overall, the AER accepts $59 million ($2010–11) in opex over the access arrangement period, which represents a 20 per cent decrease on proposed expenditures. On average, the accepted increase is 27 per cent higher than average annual expenditure in the earlier access arrangement period.

Other issues

NT Gas proposed a general cost pass through event, subject to a materiality threshold equal to one per cent of smoothed forecast revenue. The AER accepts the proposed materiality threshold, but not NT Gas's approach to defining cost pass through events. The AER proposes an alternative it considers is more in line with the requirements of the NGR. In particular, the AER proposes specific cost pass through events to increase regulatory certainty for NT Gas and users of the pipeline.

The AER accepts NT Gas's demand forecasts and forecasts for capacity utilisation. The demand growth of 2.3 per cent per annum appears to be relatively strong and is therefore considered reasonable. The AER also considers NT Gas's demand forecast methodology and assumptions are reasonable.

Terms and conditions

NT Gas's proposed access arrangement sets out terms and conditions that are not directly related to the nature or level of tariffs paid by users. NT Gas has proposed revised terms and conditions which are significantly different to those set out in the earlier access arrangement. The AER has not accepted a number of the proposed terms and conditions because in aggregate they are weighted too much in favour of NT Gas. The AER considers that amended provisions for these terms and conditions better promote the national gas objective under s. 23 of the NGL, which the AER considers requires it to balance the interests of the service provider and users.

Final decision to approve the access arrangement proposal for the Amadeus Gas Pipeline

The AER is due to make a final decision to approve the access arrangement for the AGP before the earlier access arrangement expires on 30 June 2011.

Following receipt of the proposed access arrangement on 23 December 2010, the AER intended to receive submissions by 14 February 2011 and to make a final decision to approve the access arrangement before the earlier access arrangement expires on 30 June 2011. However, PWC sought an extension to make a submission one month after submissions were due. The extension was sought because PWC was in the final stages of negotiating a 25 year gas transportation agreement with respect to the AGP.

As a result, the AER's final decision may be delayed until shortly after 1 July 2011. NT Gas and PWC have been advised of this and have not expressed any significant concerns regarding the possible delay. The earlier access arrangement in place for the AGP[14] will continue to have effect until the AER makes its access arrangement under r. 64 of the NGR.

14 Further, reference tariffs set out in the earlier access arrangement are expected to continue as well.

1 Introduction

1.1 Background

The ownership of the Amadeus Gas Pipeline (AGP) is vested in a consortium of banks and the pipeline is leased to N.T. Gas Pty Limited (NT Gas) as trustee of the Amadeus Gas Trust.[15]

NT Gas was formed from a consortium of companies to finance, construct, commission and operate the pipeline which was previously known as Amadeus Basin to Darwin Pipeline (ABDP).[16] The pipeline was commissioned in December 1986 and gas was first delivered to Power and Water Corporation (PWC) in January 1987.[17]

1.2 NT Gas's network

The AGP is approximately 1658 km which includes the Mereenie spurline, Tennant Creek and Katherine laterals, and the Pine Creek outlet.[18] NT Gas supplies gas to PWC predominantly for generating electricity in Darwin.

The AGP consists of the mainline or system backbone and comprises four gas inlet stations (Palm Valley, Mereenie, Ban Ban Springs and Weddell), a compressor station (Warrego), one odorant station (Tylers Pass), eleven mainline valves, eleven scraper stations and thirteen offtakes.[19]

1.3 Regulatory requirements

The AER is responsible for the economic regulation of covered natural gas distribution and transmission pipelines in all states and territories (except Western Australia). The AER's functions and powers are set out in the National Gas Law (NGL) and the National Gas Rules (NGR). The access arrangement for the AGP for 1 July 2001 to 30 June 2011 inclusive (earlier access arrangement) is a transitional access arrangement in accordance with schedule 1 of the NGR. The transitional arrangements set out in clause 5 of schedule 1 of the NGR apply to the review of the AGP access arrangement proposal for the period 1 July 2011 to 30 June 2016 (access arrangement period).

1.3.1 National Gas Law

The NGL states that when performing or exercising an economic regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national gas objective. The national gas objective 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

15 NT Gas, *Amadeus gas pipeline access arrangement revision proposal submission*, 23 December 2010, p. 5. (NT Gas, *Access arrangement submission*, December 2010).

16 NT Gas, *Access arrangement submission*, December 2010, p. 5.

17 NT Gas, *Access arrangement submission*, December 2010, p. 5.

18 NT Gas, *Access arrangement submission*, December 2010, p. ix.

19 NT Gas, *Access arrangement submission*, December 2010, p. ix.

> with respect to price, quality, safety, reliability and security of supply of natural gas. [20]

The AER must take into account the revenue and pricing principles when exercising its discretion in approving or making those parts of an access arrangement relating to a reference tariff. The AER may also take the revenue and pricing principles into consideration in its performance or exercise of any other economic regulatory function or power where it considers this appropriate.[21]

1.3.2 National Gas Rules

The NGR sets out the provisions the AER must apply in exercising its regulatory functions and powers when making its draft decision on the access arrangement proposal for the AGP.

1.4 Structure of draft decision

The AER's consideration of the access arrangement proposal for the AGP and accompanying access arrangement information are set out as follows:

- introductory chapters outline the regulatory requirements and pipeline services
- part A outlines the key components of the total revenue building blocks including the capital base, depreciation, the rate of return, taxation, operating expenditure and provides a summary of total revenue
- part B outlines the demand forecasts, reference tariffs and tariff variation mechanisms
- part C outlines the non-tariff components of the access arrangement proposal.

1.5 Next steps

NT Gas may submit a revised access arrangement proposal and updated access arrangement information to the AER by 27 May 2011.

Submissions on the AER's draft decision and the revised access arrangement proposal for the AGP from interested parties are due by 24 June 2011.

The AER expects to make a final decision in July 2011.

20 NGL, s. 23.

21 NGL, s. 28. The revenue and pricing principles are set out in NGL, s. 24.

2 Pipeline services

NT Gas's access arrangement describes the type and nature of services to be provided. This includes those services likely to be sought by a significant part of the market (reference services) and non-reference services.

The AER is satisfied that NT Gas has identified the pipeline to which the access arrangement relates and described the proposed pipeline services in accordance with the requirements of the NGR. Further discussion of the specified reference services and tariffs proposed by NT Gas is provided in chapter 10 of the draft decision.

2.1 Introduction

This chapter considers the pipeline services set out in NT Gas's access arrangement proposal.

2.2 Regulatory requirements

Rule 48(1) of the NGR provides that a full access arrangement must specify certain information for pipeline services, including reference services. Pipeline services include haulage services, interconnection services and ancillary services.[22] Reference services are defined as pipeline services that are likely to be sought by a significant part of the market.[23] An access arrangement must:

- identify the pipeline to which the access arrangement relates and a website at which a description of the pipeline can be inspected[24]
- describe the pipeline services the service provider proposes to offer to provide by means of the pipeline[25]
- specify the reference services, and the reference tariff for each reference service.[26]

Rule 109(1) of the NGR provides that a pipeline service provider must not make it a condition of the provision of a service that the prospective user also accept another non-gratuitous service, unless the bundling of services is reasonably necessary.

2.3 Access arrangement proposal

NT Gas has proposed to offer a "firm service" as a reference service, and interruptible and negotiated services as non-reference services in the access arrangement period.[27] The pipeline services proposed by NT Gas are set out in table 2.1 below.

22 NGL, s. 2.

23 NGR, r. 101(2).

24 NGR, r. 48(1)(a).

25 NGR, r. 48(1)(b).

26 NGR, r. 48(1)(c) and r. 48(1)(d).

27 NT Gas, *Access arrangement submission*, December 2010, pp. 10, 11.

Table 2.1: NT Gas's proposed pipeline services

Type of service	Description
Firm service	Transport from any receipt points to any delivery points on the pipeline
Interruptible services	Transport from any receipt points to any delivery points on the pipeline, where NT Gas is entitled to cease receiving gas from, or delivering gas to, the user when pipeline capacity is constrained/curtailed, or to meet the capacity requirements of other users of the firm service.
Negotiated services	Service negotiated to meet the needs of a user which differ from those of the firm or interruptible service, including potential as available services.

Source: NT Gas, *Access arrangement submission*, December 2010, p. 9.

2.4 Submissions

The AER received submissions from three interested parties about the definitions of the reference service and non-reference services.[28] The issues raised in these submissions are considered in chapter 10 of this draft decision.

2.5 AER's consideration

The AER is satisfied that:

- NT Gas has identified the pipeline to which the access arrangement relates and has provided a reference to a website at which a description of the pipeline can be inspected[29] and therefore it meets the requirements of r. 48(1)(a) of the NGR

- NT Gas has described the services which it proposes to offer to provide by means of the pipeline in section two of its proposed access arrangement, and section ten of its access arrangement information[30] and therefore it meets the requirements of r. 48(1)(b) of the NGR

- the reference service is likely to be sought by the users and prospective users. The issue of the appropriate specification of the reference service and tariffs are further considered in chapter 10 of this draft decision

- there is no information before it to suggest that the proposed non-reference negotiated service is likely to be sought by a significant part of the market and therefore considers that NT Gas's access arrangement proposal is consistent with the requirements of r. 101(2) of the NGR

28 Northern Territory Major Energy Users, *Submission to the AER regarding Application by NT Gas for New gas access arrangement for Amadeus gas Pipeline*, February 2011(NTMEU, *Submission to the AER*, February 2011); Power and Water Corporation, *Submission to the AER; Application by NT Gas for New gas access arrangement for Amadeus Gas Pipeline*, 14 March 2011(PWC, *Submission to the AER*, 14 March 2011) and Santos Limited and Magellan Petroleum Australia Limited, *Revisions to the Access arrangement for the Amadeus Basin to Darwin Pipeline*, 14 February 2011, (Santos and Magellan, *Submission to the AER*, February 2011).

29 N.T. Gas Pty. Limited, *Access arrangement for the Amadeus Gas Pipeline–01 July 2011 to 30 June 2016*, December 2010, p. 3 (NT Gas *Access arrangement proposal*, December 2010).

30 NT Gas *Access arrangement proposal*, December 2010, p. 3,N.T. Gas Pty. Limited, *Amadeus Gas Pipeline–Access arrangement information—Effective 1 July 2011– 30 June 2016*, December 2010, p. 29 (NT Gas, *Access arrangement information*, December 2010).

- the AER therefore considers that NT Gas’s access arrangement proposal meets the requirements of r. 109(1) of the NGR.

2.6 Conclusion

Based on NT Gas’s access arrangement proposal and access arrangement information, the AER is satisfied that NT Gas has identified the pipeline to which the access arrangement relates and described the proposed pipeline services in accordance with the requirements of the NGR.

Part A – Total revenue (building block components)

3 Capital base

The AER does not accept the opening capital base proposed by NT Gas of $112.4 million ($2010–11) as at 1 July 2011. In particular, the AER requires NT Gas to amend its estimated capex in 2010–11, consistent with NT Gas's own recently revised estimates. The AER also requires NT Gas to revise the depreciation used to roll forward the capital base as at 1 July 2011. After making these adjustments, the AER has calculated an opening capital base on 1 July 2011 of $97.0 million ($2010–11), $15.4 million less than that proposed by NT Gas.

NT Gas has forecast $14.4 million ($2010–11) of capex over the access arrangement period for 1 July 2011 to 30 June 2016. The AER considers that most of the forecast capex complies with the NGR. However, the AER has rejected fees related to capex project management, because the costs have not been substantiated. In addition, the AER considers the real cost escalators applied to forecast capex are excessive.

Overall, the AER considers that NT Gas must amend its forecast capex over the access arrangement period to $13.9 million ($2010–11), a reduction of 3.5 per cent compared to that proposed by NT Gas.

The AER has calculated a closing capital base on 30 June 2016 of $100.9 million ($ nominal).

3.1 Introduction

This chapter sets out the AER's consideration and analysis of the capital base that NT Gas has proposed for the access arrangement period.

3.2 Regulatory requirements

In assessing NT Gas's opening capital base, the AER is required to consider the transitional provisions of the NGR (Clause 3(2) of schedule 1 of the NGR). This relates to actual or forecast capital expenditure (new facilities investment) under section 8.21 of the Code.

In relation to the value of the opening and closing capital base, the NGR requires NT Gas to demonstrate:

- capex (by asset class) over the earlier access arrangement period (r. 72(1)(a)(i))
- how the opening capital base is arrived at, including a demonstration of how it is increased or diminished over the earlier access arrangement period (r. 72(1)(b))
- the opening capital base is derived in accordance with r. 77(2). Rule 77(2) specifies the components that contribute to the derivation of the opening capital base, including conforming capex, depreciation and redundant and disposed of assets
- forecast conforming capex (r. 72(1)(c)(i)) and how depreciation over the access arrangement period is derived (r. 72(1)(c)(ii))

- the closing capital base, derived using the formula: opening capital base plus forecast conforming capex less forecast depreciation and disposed pipeline assets (r. 78 of the NGR)
- that forecast capex is such as would be incurred by a prudent service provider (r. 79(1)(a) of the NGR)
- that forecast capex is justifiable on a ground stated under r. 79(2). That is,
    - the overall economic value is positive
    - that either the expenditure is necessary to maintain and improve the safety of services
    - complies with a regulatory obligation, or
    - meets the level of demand for services existing at the time the capex is incurred.

Rule 90 requires that the access arrangement must contain provisions governing the calculation of depreciation for establishing the opening capital base for the next access arrangement period. The provisions must resolve whether depreciation of the capital base is to be based on forecast or actual capital expenditure.

Rule 85(1) allows an access arrangement to include a capital redundancy mechanism. The AER may also require such a mechanism in the access arrangement.

The NGR also requires NT Gas to show key expenditure performance indicators to be used by the service provider to support expenditure to be incurred over the access arrangement period (r. 72(1)(f)).

3.3 Access arrangement proposal

3.3.1 Opening capital base

NT Gas has proposed an opening capital base of $112.4 million ($2010–11) as at 1 July 2011. The calculation of the opening capital base is shown in table 3.1.

Table 3.1: NT Gas proposed opening capital base ($m, 2010–11)[a]

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12
Opening capital base	228.5	216.1	202.0	188.6	170.8	153.6	139.4	131.0	117.6	105.7	112.4
plus capex	0.2	0.4	2.9	0.4	0.5	0.3	0.7	0.6	0.7	20.6	
plus speculative capex											
plus reused redundant assets											
Less depreciation	(19.1)	(20.2)	(21.5)	(22.9)	(24.4)	(17.7)	(15.5)	(15.8)	(16.2)	(16.5)	
Plus indexation	6.5	5.8	5.0	4.7	6.8	3.2	6.3	1.9	3.6	2.6	
Less redundant assets											
Less disposals		(0.0)		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)		
Closing capital base	216.1	202.0	188.6	170.8	153.6	139.4	131.0	117.6	105.7	112.4	

Source: NT Gas, *Access arrangement information*, December 2010, p. 13.
a: The AER has converted 2009–10 real dollars to 2010–11 real dollars.

3.3.1.1 Capital expenditure in the earlier access arrangement period

NT Gas indicated it had incurred capex of $27.5 million ($2010–11) in the earlier access arrangement period and proposed this amount be included in the opening capital base for the access arrangement period. Table 3.2 sets out the actual capex incurred in the earlier access arrangement period, as well as an estimate for 2010–11.[31]

31 NT Gas, *Access arrangement submission*, December 2010, p. 81.

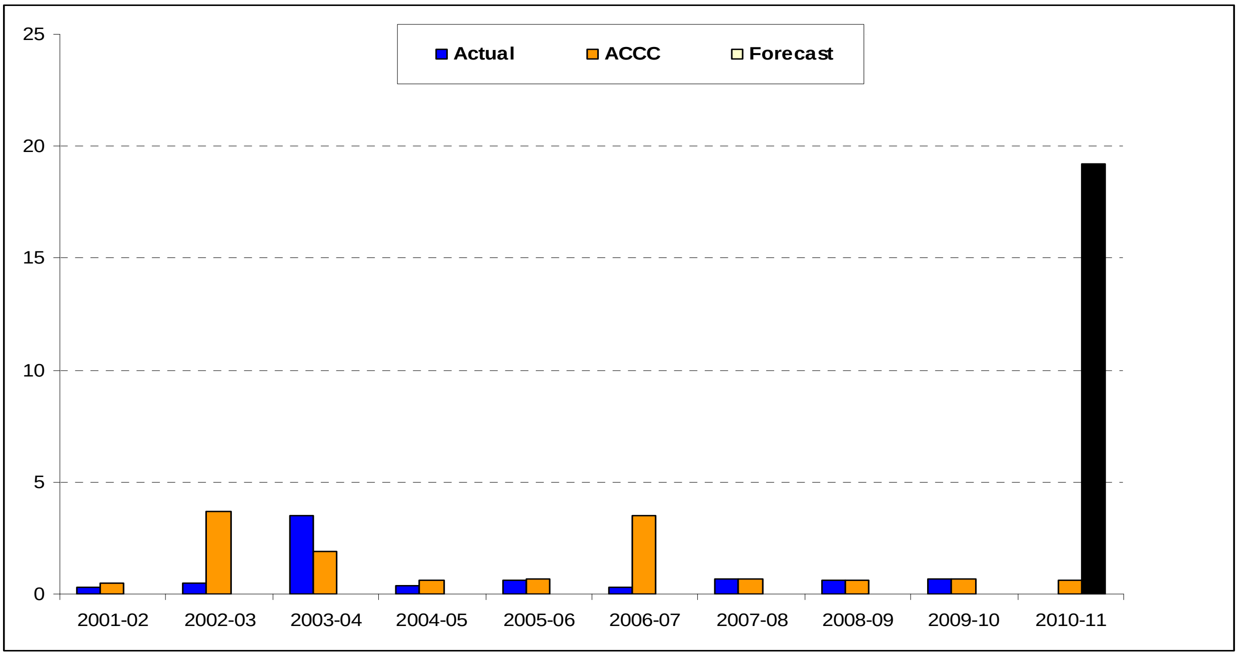
Table 3.2: Forecast and actual/estimated capital expenditure for 2006–11 ($m, 2010–11)[a]

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11[b]	Total
Forecast (ACCC approved)	0.5	3.7	2.0	0.6	0.7	3.6	0.7	0.6	0.7	0.6	13.7
Actual/ Estimated	0.3	0.5	3.6	0.5	0.6	0.4	0.8	0.6	0.7	19.7	27.5
Difference	0.2	3.3	(1.6)	0.2	0.1	3.2	(0.1)	(0)	(0)	(19.1)	(13.8)

Source: NT Gas, *Access arrangement submission*, December 2010, p. 81.
a: The AER has converted 2009–10 real dollars to 2010–11 real dollars.
b: estimate

NT Gas included $13.4 million ($2010–11) of capex in its calculation of the opening capital base, which is 100 per cent higher than the amount approved by the ACCC.[32] The overspend was significantly affected by the expenditure estimated to be incurred in 2010–11, as figure 3.1 shows.

Figure 3.1: Comparison of approved and actual/estimated capital expenditure for NT Gas for the earlier access arrangement period ($m, real, 2010–11)



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 81–82.

Table 3.3 shows NT Gas's approved and incurred capex for the major capex categories (expansion, replacement and non-system) in the earlier access arrangement

32 NT Gas, *Access arrangement submission*, December 2010, p. 81.

period. During this period, NT Gas overspent in all three capex categories. NT Gas's performance in each of these cost categories is briefly discussed below.

Table 3.3: NT Gas allowed and incurred capital expenditure for the earlier access arrangement period ($m, 2010–11)[a]

		2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	Total
Expansion	Allowed	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
	Incurred	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.41	7.2	7.6
	Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.41	7.2	7.6
Replacement	Allowed	0.0	3.2	0.1	0.0	0.1	2.7	0.1	0.0	0.1	0.0	6.2
	Incurred	0.1	0.3	3.3	0.4	0.1	0.2	0.2	0.4	0.2	12.4	17.7
	Variance	0.1	(2.9)	3.3	0.1	0.1	(2.5)	0.1	0.4	0.1	12.4	11.5
Non-system	Allowed	0.5	0.6	1.9	0.6	0.6	0.9	0.6	0.6	0.6	0.6	7.5
	Incurred	0.1	0.2	0.3	0.1	0.4	0.1	0.6	0.2	0.1	0.1	2.3
	Variance	(0.3)	(0.4)	(1.6)	(0.5)	(0.1)	(0.8)	(0.0)	(0.4)	(0.5)	(0.5)	(5.2)
Total	Allowed	0.5	3.8	2.0	0.6	0.7	3.6	0.7	0.6	0.7	0.6	13.7
	Incurred	0.3	0.5	3.6	0.4	0.6	0.3	0.7	0.6	0.7	19.7	27.5
	Variance	(0.2)	(3.3)	1.5	(0.2)	(0.1)	(3.3)	0.0	0.0	0.0	19.1	13.7

Source: NT Gas, *Access arrangement submission*, December 2010, p. 81.
a: The AER has converted 2009–10 real dollars to 2010–11 real dollars.

Expansion capital expenditure

NT Gas did not originally forecast any expansion capex over the earlier access arrangement period. However, NT Gas undertook (or expected to undertake) three expansion projects towards the end of the period.[33] These included:

- removal of check valves along the AGP, south of Ban Ban Springs in 2009–10 costing $0.37 million ($2010–11)[34]
- the Katherine Meter Station upgrade requested by PWC to support an increase in capacity in the Katherine generating facilities to be completed in 2010–11, costing an expected $7.7 million ($2010–11)[35]

33 NT Gas, *Access arrangement submission*, December 2010, p. 63.

34 NT Gas, *Access arrangement submission*, December 2010, p. 63.

35 NT Gas, *Access arrangement submission*, December 2010, p. 63.

- the Channel Island Meter Station upgrade scheduled to occur in 2010–11 at a cost of $0.6 million ($2009–10) [c-i-c] to support an increase the capacity of the Channel Island generating facilities[36]

Replacement capital expenditure

NT Gas overspent on replacement capex over the earlier access arrangement period by 187 per cent.[37] However, for most of the earlier access arrangement, replacement capex was below that forecast due to a delay in the supervisory control and data acquisition (SCADA) upgrade project. For example, the Mereenie looping project forecast to cost $2.6 million ($2010–11) was not undertaken in 2006–07.[38] The reported over spend in replacement capex was due to enhanced integrity projects that were expected to be completed in 2010–11, at a cost of $12.1 million ($2010–11).[39]

Non-systems capital expenditure

NT Gas submitted that it underspent on non-systems capex by $5.2 million ($2010–11), which represents 71 per cent of the amount that had been allowed in the earlier access arrangement period.[40]

3.3.1.2 Adjustment to the capital base for inflation in the earlier access arrangement period

NT Gas proposed an adjustment to the capital base using actual inflation based on the consumer price index (CPI).[41] For 2010–11, NT Gas estimated an inflation rate of 2.50 per cent.[42] NT Gas's proposed inflation rates for adjusting the capital base is set out in table 3.4.

Table 3.4: Inflation rates for adjusting the capital base (%)

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11[a]
Inflation rates	2.64	2.69	2.48	2.49	3.98	2.07	4.51	1.46	3.05	2.50

Source: NT Gas, *Access arrangement submission*, December 2010, p. 98.
a: The value for 2010–11 is a forecast.

36 NT Gas, *Access arrangement submission*, December 2010, attachment D (confidential).

37 NT Gas, *Access arrangement submission*, December 2010, p. 81.

38 NT Gas, *Access arrangement submission*, December 2010, pp. 65–66.

39 NT Gas, *Access arrangement submission*, December 2010, p. 68. These projects include Channel Island meter replacement, Channel Island piggability project, Replacement of Elliot heaters, Southbound piggability projects, Cathodic protection upgrade stage 2, Hazardous area assessment and equipment replacement, Palm Valley filtration and slam-shut, Heat shrink sleeve replacement and Below ground station pipework recoating.

40 NT Gas, *Access arrangement submission*, December 2010, p. 93.

41 NT Gas, *Access arrangement submission*, December 2010, p. 93.

42 NT Gas, *Access arrangement information*, December 2010, p. 93.

3.3.1.3 Depreciation in the earlier access arrangement period

The ACCC approved straight line accelerated method of depreciation for the earlier access arrangement period.[43] This was a combination of depreciation of the capital base (return of capital) and indexation.[44] NT Gas has submitted that to roll forward the capital base, it disaggregated the depreciation and indexation components from the depreciation schedule in the ACCC final decision.[45] Table 3.5 sets out NT Gas's proposed depreciation amounts for the earlier access arrangement period.

Table 3.5: NT Gas's proposed depreciation for the earlier access arrangement period ($m, nominal)[a]

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11[b]
Regulatory depreciation per ACCC	14.1	15.5	17.1	18.8	20.8	14.4	12.5	13.1	13.7	14.4
Indexation	6.5	5.8	5.0	4.7	6.8	3.2	6.3	1.9	3.6	2.6
Straight line depreciation	19.1	20.2	21.5	22.9	24.4	17.7	15.5	15.8	16.2	16.6

Source: NT Gas, *Access arrangement submission*, December 2010, p. 98, NT Gas, *Access arrangement submission*, December 2010, Attachment E–1 (confidential).
a: This table disaggregates the ACCC 2002 final decision forecast depreciation.
b: The value for 2010–11 is a forecast.

3.3.1.4 Capital redundancy mechanism

NT Gas proposed that no assets had become redundant in the earlier access arrangement period.[46]

3.3.2 Projected capital base

NT Gas proposed a projected closing capital base on 30 June 2016 of just over $110 million ($2010–11). The calculation of the projected capital base is shown in table 3.6.

43 ACCC, *Final decision, Access arrangement proposed by NT Gas Pty Limited for the Amadeus Basin to Darwin Pipeline*,4 December 2002, p. 61 (ACCC, *Final decision–NT Gas*, December 2002).

44 NT Gas, *Access arrangement submission*, December 2010, p. 92.

45 NT Gas, *Access arrangement submission*, December 2010, p. 92.

46 NT Gas, *Access arrangement submission*, December 2010, p. 91.

Table 3.6: NT Gas projected capital base ($m, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Opening capital base	112 433	117 192	115 032	112 678	109 688
Plus forecast capital expenditure	9317	1653	1737	1398	1674
Less forecast regulatory depreciation	4558	3814	4091	4388	968
less forecast disposals					
Less forecast redundant assets					
Closing capital base	117 192	115 032	112 678	109 688	110 394

Source: NT Gas, *Access arrangement information*, December 2010, p. 12.

3.3.2.1 Forecast capital expenditure for the access arrangement period

NT Gas proposed forecast capex of $14.4 million ($2010–11) for the access arrangement period. The proposed forecast capex is set out in table 3.7.

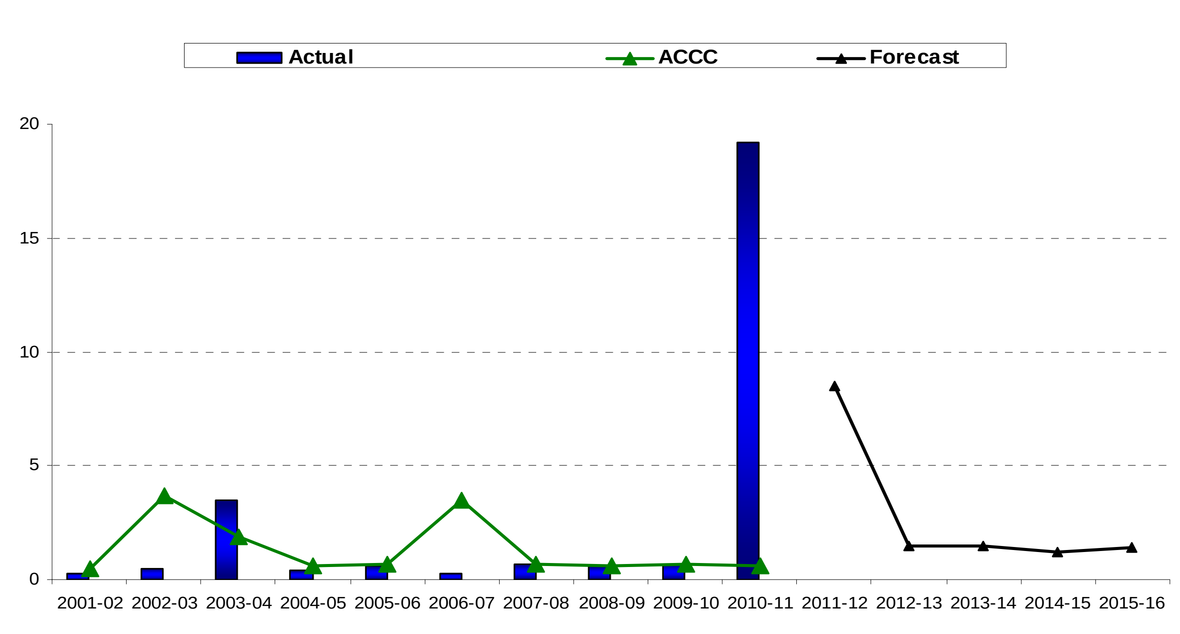
Table 3.7: Proposed forecast capital expenditure for the access arrangement period ($m, 2010–11)[a]

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Pipeline	7.9	0.9	0.9	0.8	0.9	11.5
Compression	0.0	0.0	0.0	0.0	0.0	0.0
Meter Stations	0.6	0.1	0.0	0.1	0.0	0.9
SCADA & Communications	0.1	0.3	0.5	0.1	0.4	1.4
Operation & Management facilities	0.1	0.1	0.1	0.1	0.1	0.6
Building	0.0	0.0	0.0	0.0	0.0	0.0
Total	8.7	1.5	1.5	1.2	1.4	14.4

Source: NT Gas, *Access arrangement information*, December 2010, p. 9.
a: The AER has converted 2009–10 dollars to 2010–11 real dollars.

Figure 3.2 below shows actual and estimated capex from the earlier access arrangement period and forecast capex for the access arrangement period. On average, there is a 0.1 per cent per annum[47] increase in total capex in the access arrangement period when compared to the earlier access arrangement period.[48]

Figure 3.2: NT Gas capital expenditure actual, approved and forecast($2010–11)



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 81–82, 89.
a: The value for 2010–11 is a forecast.

3.3.2.2 Adjustment of the capital base for inflation in the access arrangement period

To roll forward the capital base over the access arrangement period, NT Gas included a forecast rate of inflation of 2.5 per cent.[49]

3.3.2.3 Forecast depreciation allowance in the access arrangement period

NT Gas's proposed allowance for depreciation in the access arrangement period is discussed in chapter 4 of the draft decision.

3.4 Consultant review

The AER engaged Wilson Cook & Co Limited, engineering and management consultants, to review NT Gas's proposed capex (Wilson Cook).[50] This included a review of the capex in the earlier access arrangement period, as well as NT Gas's forecast capex for the access arrangement period.

For the earlier access arrangement period Wilson Cook considered the following[51]:

47 The earlier access arrangement period was a ten–year period, for comparison reasons the figure for the access arrangement period has been doubled.

48 NT Gas, *Access arrangement submission*, December 2010, pp. 81, 83.

49 NT Gas, *Access arrangement submission*, December 2010, p 93.

50 Wilson Cook, *Report–NT Gas*, January 2011, p. 5.

- an element of NT Gas's contract with its primary customer required NT Gas to inform and gain approval of the customer to go ahead with material capex. As such, there was a reasonable level of assurance that all material capex projects were prudent and efficient[52]

- the most significant of these projects is the Katherine meter station upgrade, at a cost (estimated) of $7.6 million. As well as increasing the metering capacity of this station, due to the age of the installation many aspects of it needed to be upgraded to comply with present day standards. Wilson Cook considered that a detailed cost breakdown is not provided, however, the estimated internal rate of return was in excess of the nominal pre-tax WACC[53]

- Wilson Cook noted that the proposed cost of the three expansion projects sum to a larger total than the total amount of proposed expansion capex ($8.89 million against $7.4 million), and this discrepancy had not been explained[54]

Wilson Cook noted the following points concerning forecast capex in the access arrangement period:

- the majority of the forecast capex lay in the 'enhanced integrity program', which continued from the earlier access arrangement

- aside from the 'enhanced integrity program', Wilson Cook considered that, despite a lack of detailed information the remaining general capex (e.g. SCADA upgrades, replacement of tools and minor equipment etc.) appeared justified

- the forecast for non-system capex was small, and despite little information being provided, appeared justified.

Wilson Cook recommended that the AER seek further information from NT Gas on some aspects of its expenditure. This included more detail on costs of certain projects and apparent discrepancies in descriptions of the projects in the access arrangement.

3.5 Submissions

Submissions on the capital base were received from Northern Territory Major Energy Users (NTMEU), Power and Water Corporation (PWC) and Northern Territory Treasury (NT Treasury).[55]

NTMEU submitted that over the earlier access arrangement period, the actual capex was lower than the ACCC approved capex of $13.4 million (nominal). Further, NTMEU submits that there is large increase in capex over 2010–11 and 2011–12.

NTMEU were concerned that the amount of forecast depreciation, as determined by the ACCC, has not been completely accounted for in the roll forward of the regulatory asset base.[56]

52 NTMEU, *Submission to the AER*, February 2011, p.13.

Further, NTMEU submitted that the proposed forecast capex for 2010–11 and 2011–12 and its timing should be closely examined.[57]

PWC submitted that it considers the opening capital base to be excessive and that the depreciation allowance is overstated for the following reasons:

- actual capex incurred by NT Gas during the earlier access arrangement period was financed by PWC
- all compression on the pipeline is redundant and thus should not form any part of the calculation of deprecation
- the historical capex on O&M facilities and SCADA were funded by PWC under existing contractual arrangements and as such should be fully depreciated[58]

PWC submitted that it was concerned with forecast capex in 2010–11 and 2011–12 and in particular[59]:

- whether or not NT Gas had the capacity to deliver the projects within the nominated time frame
- that a significant proportion of the projects were being fast tracked despite not being urgent
- projects were being accelerated and with some being added simply to suit NT Gas. For example, NT Gas proposed to begin southbound pigging in 2015–16. However, the South Bound Piggability project was forecast to be complete in 2011–12 as part of the enhanced integrity program
- that some proposed projects did not belong in forecast capex as they were completed in the earlier access arrangement period.[60]

PWC further submitted that the proposed scope of the enhanced integrity project forecast to be undertaken in 18 months was substantial.[61] Further, PWC indicated that many of the projects in the enhanced integrity program were remedial integrity activities, which would be carried out on a year-on-year basis. PWC has suggested that the forecast capex be scrutinised carefully against r. 79 of the NGR.[62]

56 NTMEU, *Submission to the AER*, February 2011, p. 13.

57 NTMEU, *Submission to the AER*, February, p. 13.

58 PWC, *Submission to the AER*, 14 March 2011,pp. 5–8.

59 PWC, *Submission to the AER*, 14 March 2011, pp. 5–8.

60 PWC, *Submission to the AER*, 14 March 2011, pp. 5–8. These projects include: Below Ground Station Pipework Recoating project which is traditionally an opex item; Heat Shrink Sleeve Replacement project; in the past it has been treated as non-routine opex and Cathodic Protection Upgrade project; should represent O&M savings in the future.

61 PWC, *Submission to the AER*, 14 March 2011, pp. 5–8.

62 PWC, *Submission to the AER*, 14 March, pp.5–8.

PWC also submitted that NT Gas did not provide sufficiently detailed information on forecast capex in the years from 2012–13 to 2015–16.[63] Overall, PWC has considered that there was an over-estimation in forecast capex.

The NT Treasury considered that forecast capex in 2010–11 and 2011–12 was excessive.[64] Further, it submitted that the forecast capex over the access arrangement period was high and more than double the levels in the earlier access arrangement period. [65]

3.6 AER's consideration

The AER is satisfied with the majority of the components of NT Gas's proposed opening capital base. However, the AER requires NT Gas to revise its opening capital base to account for capex that had been estimated to occur in 2010–11 but will not be undertaken. The AER also requires NT Gas to reconcile the calculation of the "residual amount"[66] used by NT Gas to roll forward its capital base at 1 July 2011.

With respect to forecast capex over the access arrangement period, the AER largely has accepted the amounts forecast by NT Gas. The need to maintain the safety and integrity of the pipeline over the access arrangement period and beyond provides sufficient justification for the proposed capex. The AER is also satisfied that, for the most part, the forecast costs are prudent and efficient. However, the AER considers amendments must be made to the capex forecast to remove project management fees and to revise the accepted rates of real cost escalation.

3.6.1 Opening capital base

Two steps are required to calculate the opening capital base at 1 July 2011:

- first, the value of the capital base at 1 July 2001 is obtained from the access arrangement review undertaken for the earlier access arrangement period and an adjustment is made to account for any difference between actual and estimated capex in 2000–01. This becomes the opening capital base for the earlier access arrangement period;
- second, the opening capital base at 1 July 2001 is rolled forward to 30 June 2011. This involves:
    - adding conforming actual capex over the earlier access arrangement period
    - removing regulatory depreciation
    - removing any redundant capital and disposals and

63 PWC, *Submission to the AER*, 14 March 2011, pp. 5–8.

64 Northern Territory Treasury, *Submission to the AER, proposes access arrangement for the Amadeus Gas Pipeline*, 21 March 2011, p. 2. (NT Treasury, *Submission to the AER*, 21 March 2011).

65 NT Treasury, *Submission to the AER*, 21 March 2011, p. 2.

66 NT Gas, *Access arrangement submission*, December 2010, p.92.

- indexing the capital base and other components of the roll forward for actual inflation.

While the AER is satisfied with the majority of NT Gas's calculation of the opening capital base, the AER does not accept NT Gas's estimated capex in 2010–11. As a result, the AER does not accept NT Gas's proposed opening capital base and requires NT Gas to amend its access arrangement information as set out in amendment 3.1.

3.6.1.1 Opening capital base for the earlier access arrangement period

The AER considers that NT Gas has correctly updated the opening value of the capital base in the earlier access arrangement period. That is, the value of the capital base on 1 July 2001.

3.6.1.2 Conforming capital expenditure in the earlier access arrangement period

The AER is required to consider whether the capex in the earlier access arrangement period is conforming.[67] The AER does not consider that the capex incurred and estimated by NT Gas over the earlier access arrangement period is consistent with r. 79(1)(a) of the NGR. As a result, the AER is proposing to remove $13.6 million ($2010–11) from NT Gas's proposed opening capital base at 1 July 2011.

In reaching this view, the AER has considered the following information:

- in its access arrangement proposal, NT Gas submitted that capex was estimated to increase sharply in 2010–11 to address pipeline integrity concerns through its 'enhanced integrity program'.[68] However, subsequently, NT Gas provided the AER with information outlining significant revisions to its estimates for 2010–11.[69] NT Gas submitted much of the estimated capex in 2010–11 would not proceed in that year.[70] Based on the updated information provided by NT Gas, the AER does not accept the estimated capex for 2010–11 as set out in the access arrangement proposal as it does not comply with r. 74(2). To reflect a more accurate estimate of conforming capex in 2010–11, NT Gas is required to amend its capex in accordance with amendment 3.2.

- aside from the revisions to the 'enhanced integrity program' and capex related to the Katherine Meter Station upgrade, the variances between the actual and allowed non-system expenditure were relatively minor.

The AER does not agree with the submission from PWC that suggested certain capex amounts incurred during the earlier access arrangement period should be regarded as non-conforming. PWC submitted that some operating facilities and data acquisition assets (SCADA) were specifically funded under its contract with NT Gas. As such,

67 NGR, r. 79(1)(a). The relevant test is whether the expenditure was justified and would have been incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services.

68 NT Gas, *Access arrangement submission*, December 2010, p. 81.

69 NT Gas, Email to AER, *AER.NTGAS.15-18 - Update and details on special projects*, 25 February 2011.

70 NT Gas, Email to AER, *AER.NTGAS.15-18 - Update and details on special projects*, 25 February 2011.

PWC considered these represent capital contributions and should not be included in the capital base.[71]

The AER considers the reference tariff in the earlier access arrangement period was based on an expected level of costs to be recovered. However, PWC and NT Gas have negotiated an alternative contractual approach for costs to be recovered. This contracted tariff was different to that specified in the access arrangement and, as a result, may have had different requirements for capital contributions to be made. The AER considers revenues recovered under this contract can not easily be matched to revenue recoveries allowed for in the approved access arrangement. PWC did not provide information on the amounts it claims to have contributed toward capex, nor did it identify the relevant assets.

NT Gas indicated in its access arrangement proposal that these recoveries from PWC were treated as revenue and the AER accepts this approach.[72] In rolling forward the asset base, the AER considers that the actual capex spent on the assets referred to by PWC should be included in the capital base. In addition, the AER also considers the forecast depreciation associated with these assets (adjusted for actual inflation) and as determined by the ACCC, should be subtracted from the capital base.

3.6.1.3 Depreciation used in the roll forward model

The AER accepts that forecast depreciation (adjusted for actual inflation) as approved by the ACCC in the earlier access arrangement period should be used to roll forward the capital base to 1 July 2011. However, when the AER reviewed NT Gas's roll forward model (RFM), the AER found that the method applied by NT Gas to adjust the depreciation amounts for the difference between actual and forecast inflation understated the amount of depreciation. In a response to the AER, NT Gas provided a demonstration of the depreciation calculation method submitted in its proposal.[73] The AER found that NT Gas had omitted inflation adjustments to the nominal depreciation component and that only the indexation component had been adjusted.[74]

The AER recalculated NT Gas's depreciation taking into account changes to inflation on the nominal and indexed depreciation amounts. The AER's calculations result in a reduction of NT Gas's opening capital base by $0.8 million ($2010–11).

Table 3.8 sets out the AER approved and NT Gas's proposed depreciation amounts for the earlier access arrangement period.

71 PWC, *Submission to the AER*, 14 March 2011, p. 5.

72 NT Gas, *Access arrangement submission*, December 2010, p. 91.

73 NT Gas, Email to AER, *Response to information request*, January 2011.

74 NT Gas, Email to AER, *AER.NTGAS.15–18–Update and details on special projects*, 25 February 2011, attachments (confidential).

Table 3.8: Approved depreciation and NT Gas's proposed for the earlier access arrangement period ($m, nominal)

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11[b]
AER approved straight line depreciation	19.3	20.5	21.5	22.9	24.6	17.7	15.8	15.8	16.2	16.5
NT Gas proposed depreciation	19.1	20.2	21.5	22.9	24.4	17.7	15.5	15.8	16.2	16.6

Source: NT Gas, *Access arrangement submission*, December 2010, p. 99, AER Analysis.

3.6.1.4 Adjustment to the capital base for inflation

The AER considers that the inflation rate used to index the capital base should be consistent with the inflation rate used for the annual tariff variation mechanism. NT Gas's proposed RFM uses the change in June to June CPI figures to adjust the capital base for inflation.[75] This is not consistent with the annual tariff variation mechanism, which uses the change in March to March CPI figures.[76] Consequently, the AER considers that NT Gas must adjust its proposed RFM so that it uses the change in March to March CPI to calculate the inflation adjustment of the capital base. The effect of this change is to increase the opening capital base as at 1 July 2011 in nominal terms by more than $0.3 million. The inflation rate for 2010–11 will be updated for the final decision when the CPI for the March quarter 2011 is available.

3.6.1.5 Redundant capital

PWC submitted that the Warrego Compressor Station is redundant, and should not be included in the calculation of depreciation amounts.[77] The capital redundancy mechanism in NT Gas's earlier access arrangement provides for the removal of redundant assets from the asset base.[78] NT Gas has also proposed a capital redundancy mechanism for the access arrangement period.[79]

Assets are considered redundant under the NGR, and previously under the Code, when they cease to contribute in any way to the provision of pipeline services.[80] The Warrego Compressor Station was installed to pressurise gas being transported north from the Amadeus Basin. The AER accepts that since its installation, the direction of gas flow has changed as gas is now delivered from the Blacktip gas field which is connected at the northern end of the pipeline. Therefore, the compressor station is currently not used by NT Gas in the provision of pipeline services.

75 NT Gas, *Access arrangement submission*, December 2010, attachment E-1, (confidential).

76 NT Gas, *Access arrangement submission*, December 2010, p. 148.

77 PWC, *Submission to the AER*, 14 March 2010, pp. 3–4.

78 NT Gas, *Access arrangement for the Amadeus Basin to Darwin Pipeline*, February 2003, p. 15.

79 NT Gas, *Access arrangement proposal*, December 2010, p.15.

80 NGR r. 85(1), and Code, s. 8.27.

In response to the AER, NT Gas submitted that the compressor is kept in operational condition in case it is needed, and could potentially be converted for use in alternative gas flows scenarios.[81]

The AER accepts that, at this stage, the compressor continues to provide an operational capability (despite not being in current use) and is, therefore not a redundant asset. The compressor consequently meets the requirements of r. 79 of the NGR. However, the AER will reassess whether the compressor has been required to provide pipeline services during the access arrangement period at the next access arrangement review.

3.6.1.6 Summary on the opening capital base

The AER has considered the components of NT Gas's proposed opening capital base. The AER requires an amendment to the opening capital base to account for an adjustment to capex, depreciation and inflation in the earlier access arrangement period. The AER has calculated the opening capital base as at 1 July 2011 to be $99.5 million ($2010–11) compared to $112.4 million (nominal) proposed by NT Gas. As a result, the AER does not consider that NT Gas's proposed opening capital base is consistent with r. 77(2) of the NGR. NT Gas is required to amend its access arrangement information as outlined in amendment 3.1.

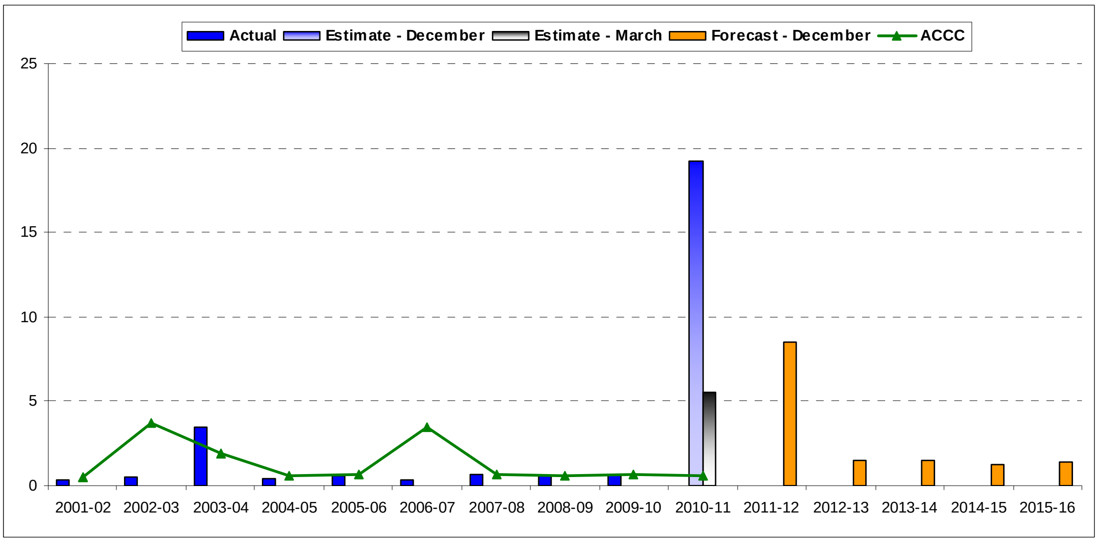
3.6.2 Projected capital base

The closing capital base is calculated by taking the opening value on 1 July 2011 and adding to it forecast conforming capex, removing forecast depreciation and then adjusting for inflation and expected capital contributions.

3.6.2.1 Forecast capital expenditure

In its proposal, NT Gas forecast capex of $14.4 million ($2010–11) in the access arrangement period. NT Gas's actual and forecast capex, including its revised estimate for 2010–11, are shown in figure 3.3.

Figure 3.3: Allowed, actual and proposed capex ($2010–11, $ m)

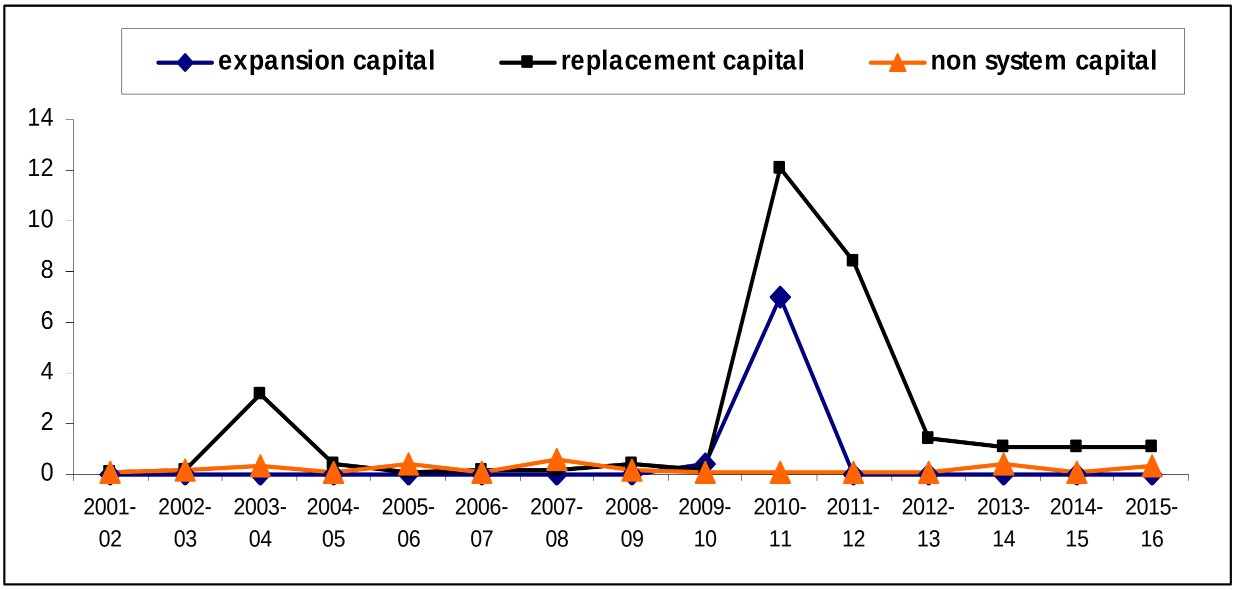


81 NT Gas, Email to AER, *Response to AER.NTGas.39*, 23 March 2011.

Source: NT Gas, *Access arrangement submission*, December 2010, pp. 81–81, 89, NT Gas, Email to AER, *NT Gas submission on AA revision proposal– revised capex*, 18 March 2011, attachments (confidential).

Figure 3.4 shows proposed capex by purpose: expansion, replacement and non-system capex. There are significant increases in two of the three categories, with the most notable being the replacement program. Figure 3.4 also shows how the ‘enhanced integrity program’ (which is part of the replacement capex) was to be spread across 2010–11 and 2011–12. NT Gas forecast $8.4 million ($2010–11) would be spent in 2011–12.[82]

Figure 3.4: NT Gas’s forecast capital expenditure by purpose – 2001–11 to 2011–16



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 81, 83.

The AER considers that NT Gas’s forecast capex program requires amendment. The AER accepts capex of $13.9 million ($2010–11) compared to NT Gas’s proposal of $14.4 million ($2010–11), a decrease of 3.9 per cent.

The AER’s consideration of the replacement capex and non-system capex elements of NT Gas’s capex program are set out below, followed by a consideration of other factors affecting the capex forecasts.

3.6.2.2 Replacement capital expenditure

In its assessment of replacement capex, the AER assessed NT Gas’s proposed ‘enhanced integrity program’ in accordance with the new capex criteria under r. 79 of the NGR. However, for ease of reading, the AER’s assessment applies the new capex criteria to each of the following aspects:

- whether the program is necessary;
- whether the costs have been estimated appropriately; and

82 NT Gas, *Access arrangement submission*, December 2010, p. 83.

- whether it is necessary to undertake the replacement in the timeline proposed by NT Gas.

These matters are considered in the following sections.

Necessity of the program

The AER considers that NT Gas has established a requirement to maintain the integrity and improve safety of services offered by the pipeline and to comply with regulatory obligations in accordance with the NGR.[83] The AER accepts that as a pipeline ages, maintenance and replacement of degraded assets will be required.[84] The AER is also aware that capex during the earlier access arrangement period assumed the pipeline may have limited further use beyond the access arrangement period. Given the anticipated continuing use of the pipeline, due to new gas sources, the AER accepts there may be a need for some catch up of replacement capex in the access arrangement period. On this basis, the AER considers the proposed enhanced integrity program is designed to address these issues. Table 3.9 outlines each of the projects that comprise the enhanced integrity program and the justification of these projects on the basis of safety and integrity.

Table 3.9: Justification for the projects that make up the enhanced integrity program.

Project	Justifications
Channel Island meter replacement	metering accuracy requirements for integrity of services
Channel Island piggability project	ensure ongoing safety and integrity of the pipeline
Replacement of Elliot heaters	ensure ongoing compliance with NT Gas's obligations to meet its contract specified quality specification
Southbound piggability project	periodic integrity surveys are a requirement of AS2885
Cathodic protection upgrade–Stage 2	ensure the integrity and safety of the pipeline through ongoing compliance with AS2885, AS/NZS2832.1 and AS/NZS 2832.1
Hazardous area assessment and equipment replacement	ensure the safety of sites along the AGP and compliance with AS2430, AS3000 and AS2381
Palm Valley filtration and slam-shut	ensure the integrity of the pipeline and maintain and improve the safety of services provided by means of the pipeline
Heat Shrink sleeve replacement	ensure the ongoing structural integrity and safety of the pipeline and to comply section 3.3 of AS2885:3
Below ground station pipework recoating	ensure the ongoing integrity and safety of the pipeline and to comply with existing section 5.5 of AS2885:3

Source: NT Gas, *Access arrangement submission*, December 2010, pp. 64–77.

The NTMEU, in its submission noted that many of the projects have been required for a number of years (e.g. the Channel Island meter station). However, it submitted that

83 NGR, r. 79(2)(c)(i) to r. 79(2)(c)(iv).

other projects (such as the cathodic protection and coating replacement projects, and 'Hazop' assessments and replacements) are ongoing work that should be continuously addressed and therefore would be in the regular annual capex works.[85]

The AER accepts that aspects of the program should proceed in order for the pipeline to be maintained for future use. This view is supported by Wilson Cook, which considered NT Gas's approach to setting the priorities of its work program was sound.[86] Wilson Cook also noted the age of the pipeline contributed to the need for the refurbishment.[87] On this basis, the AER accepts the need for the enhanced integrity program proposed by NT Gas as it complies with r. 79(2)(c)(i) to r. 79(2)(c)(iv) of the NGR.

Costs of the enhanced integrity program

The AER has found that most of the capex proposed by NT Gas is justified under r. 79(1)(a) of the NGR. The AER accepts that the operating environment for the AGP poses many challenges. For example, climatic extremes of wet and dry seasons along the length of the AGP, which is arid in the south and tropical in the north. In addition, the remoteness of the AGP imposes to travel that reduces effective working hours of staff and would lead to location specific costs, such as travel, accommodation, flights and related allowances.

Having considered the information on the 'enhanced integrity program' provided by NT Gas, Wilson Cook advised the costs of the program was reasonable and justified.[88] Wilson Cook reached its view having undertaken a review of the scope and cost of each project part of that makes up 'enhanced integrity program'.[89] It also considered that as the pipeline is no longer new, the proposed expenditure was to be expected in terms of its nature and scope.[90]

In total, the AER accepts forecast replacement capex of $13.9 million ($2010–11), a decrease of $0.5 million ($2010–11) compared to that proposed by NT Gas. This forecast includes the removal of project management fees and revised real cost escalators (see section 3.6.2.4). Overall, the accepted forecast represents a decrease of 3.9 per cent on the total amount proposed by NT Gas over the access arrangement period. A comparison of the proposed costs and those accepted by the AER are shown in figure 3.5 below.

85 NGR, r. 79(2)(c)(i) to r. 79(2)(c)(iv).

85 NTMEU, *Submission to the AER*, 28 February 2011, pp. 17–18.

86 Wilson Cook, *Report – NT Gas*, January 2011, p. 4.

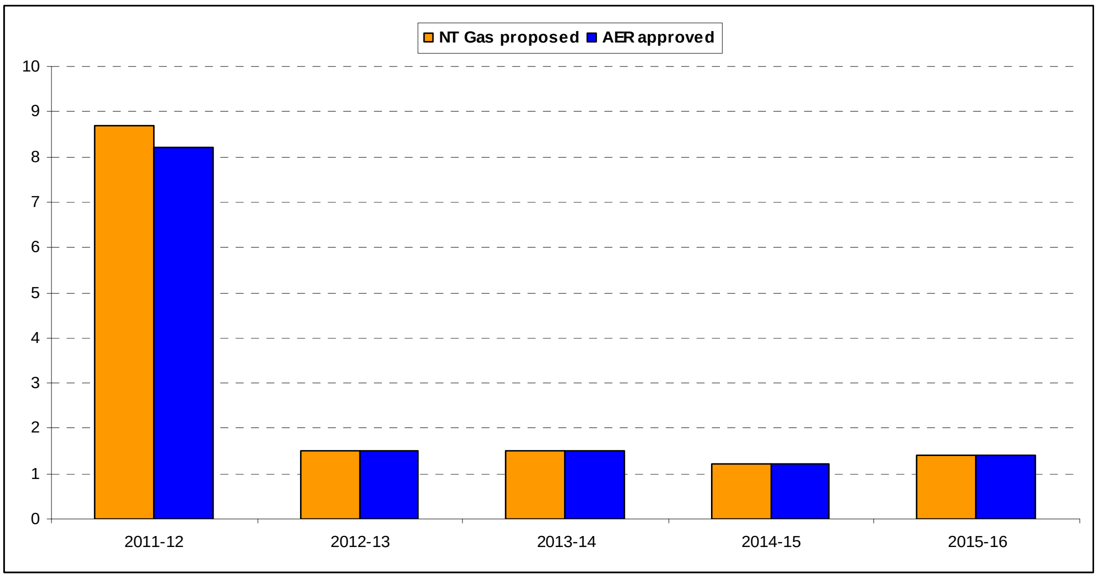
87 Wilson Cook, *Report – NT Gas*, January 2011, p. 3.

88 Wilson Cook, *Report – NT Gas*, January 2011, p. 5.

89 Wilson Cook, *Report – NT Gas*, January 2011, pp. 4–5.

90 Wilson Coon, *Report – NT Gas*, January 2011, pp. 4–5.

Figure 3.5: NT Gas proposed forecast capex compared to AER draft decision.



Source: NT Gas, *Access arrangement submission*, December 2010, p. 83, AER analysis.

Timing of the enhanced integrity program

NT Gas submitted that the enhanced integrity program was essential for technical regulatory obligations including a licence requirement and to ensure the ongoing integrity of the pipeline.[91] There is no specific obligation on NT Gas to undertake these works at the rate it has proposed. However, as noted earlier, NT Gas is required to maintain the pipeline to meet certain engineering and safety standards.

The AER has examined whether it is necessary to undertake the full program in the time proposed by NT Gas. The AER accepts the view expressed by NT Gas in its proposal that if mining activity returns to the historically high levels before the global financial crisis, there is some risk costs may rise if high levels of activity in mining sector cause labour costs to rise at rates higher than anticipated.

Therefore, the AER is satisfied these costs would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice and are justifiable.[92]

Revised timing of the 'enhanced integrity program'

On 31 January 2011, the AER requested NT Gas to confirm whether the significant increases in capex estimated for 2010–11 remained accurate.[93] A preliminary response was received from NT Gas on 25 February 2011[94] and more detailed information was

91 NT Gas, *Access arrangement submission*, December 2010, p. 66.

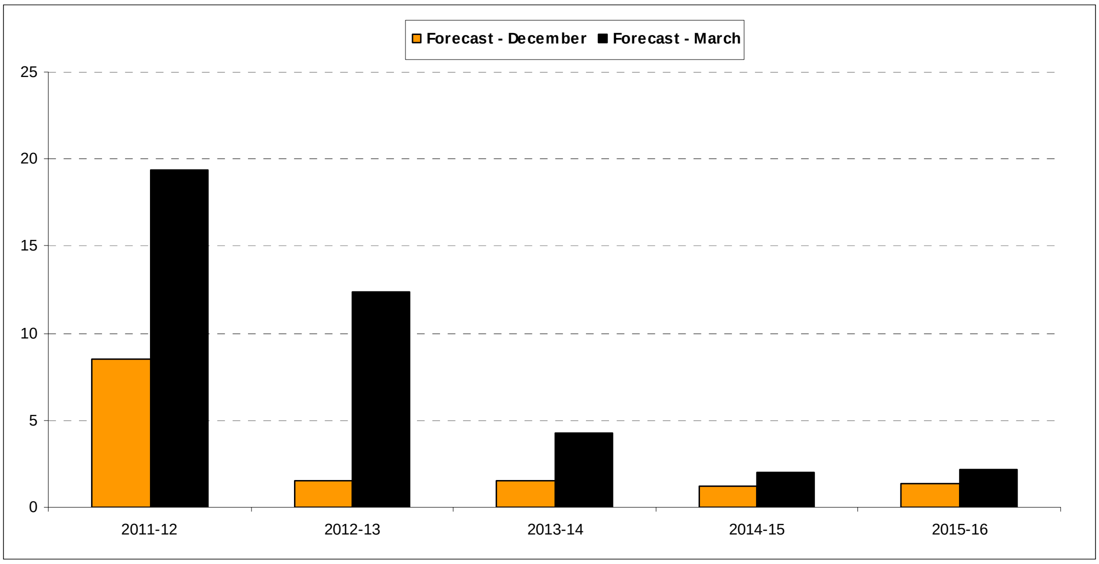
92 NGR, r. 79(1).

93 AER, Email to NT Gas, *Arrangements for AGP information session*, 28 January 2011.

94 NT Gas, Email to AER, *AER.NTGAS.15-18–Update and details on special projects*, 25 February 2011, attachments (confidential).

provided on 18 March 2011.[95] The revised figures included an update of the capex estimated in 2010–11 as well as revised forecast of capex (see figure 3.6 below) in the access arrangement period. The information provided in March included an update of capex (and opex) forecasts, depreciation schedules, revised post-tax revenue model (PTRM) and tariffs, amongst other things.

Figure 3.6: NT Gas's forecast December capex vs. March capex



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 81–81, 89, NT Gas, Email to AER, *NT Gas submission on AA revision proposal– revised capex*, 18 March 2011, attachments (confidential).

The AER has not taken into account the significant revisions to the forecasts provided by NT Gas in March 2011 in preparing the draft decision. The AER has assessed NT Gas's forecast expenditure on replacement capex as included in its proposed access arrangement submitted in December 2010.

The revisions include both the deferral of NT Gas's 'enhanced integrity program' and increases to the forecast cost of the program. In particular, capex for the program in 2010–11 had been estimated to be $12.1 million in December 2010 but in March 2011 was estimated to be $5.1 million.[96] Overall, the forecast cost of the 'enhanced integrity program', which was to be undertaken in 2010–11 and 2011–12 at a cost of $18.7 ($2010–11) million, was increased to $38.7 million ($2010–11) commencing in 2011–12. The AER considers that revisions of such significance in such a short period of time places some doubt on the ability of NT Gas to prepare reliable forecasts. As such, the AER considers that there is a high likelihood that the revised estimates provided by NT Gas will be inaccurate. In these circumstances it is more appropriate for NT Gas to bear the risks associated with inaccurate forecasting rather than users. The capex forecast for the access arrangement period accepted by the AER already represents a significant increase on the capex undertaken in the earlier access

95 NT Gas, Email to AER, *NT Gas submission on AA revision proposal– revised capex*, 18 March 2011, attachments (confidential).

96 NT Gas, Access arrangement submission, December, p. 83, NT Gas, Email to AER, NT Gas submission on AA revision proposal– revised capex, 18 March 2011, attachments (confidential).

arrangement period. An even higher forecast has not been justified by NT Gas at this time.

For the purpose of the draft decision the AER has assessed the forecast capex program as it was proposed by NT Gas in December 2010. The AER considers it would be inappropriate to prepare its draft decision with respect to the revised forecasts for a number of reasons. First, the NGR requires service providers to provide an access arrangement proposal and access arrangement information at the same time. Second, the revised forecasts are not publicly available and interested parties have had no opportunity to comment on the revisions. Third, the AER and its consultants have had little opportunity to review the revised costs in any level of detail.

3.6.2.3 Non-systems capital expenditure

Non-system capex is largely made up of annual routine and non-annual elements such as office equipment and computers and is forecast to be on average $0.2 million per annum ($2010–11) over the access arrangement period. This compares with a similar average expenditure of $0.2 million per annum in the earlier access arrangement period. Given the level of expenditure is expected to remain at around the same level, the AER accepts the proposed forecast complies with r. 79(2)(c) of the NGR.

The AER accepts that non-systems capex is necessary to ensure continued operation of the pipeline to maintain and improved the safety of services,[97] maintain integrity of services,[98] and to comply with ongoing regulatory obligations.[99]

Supporting the proposed forecasts, Wilson Cook considered the proposed non-system capex was made up of routine expenditure based on the earlier access arrangement period plus expected upgrades of data and voice communications in 2013–14 and 2015–16.[100] As a consequence, the AER is satisfied that capex for non-systems proposed by NT Gas is prudent and complies with the NGR. [101]

3.6.2.4 Other adjustments made to the projected capital base

Project management fees

The AER does not accept the project management fees submitted by NT Gas. NT Gas has proposed a general project management fee rate of [c-i-c] per cent that has been added to all capex items with the exception of expenditure on the Katherine Meter Station project.[102] Table 3.10 outlines the amount of project management fees that have been applied to each project.

97 NGR, r. 79(2)(c) (i).

98 NGR, r. 79(2)(c)(ii).

99 NGR, r. 79(2)(c)(iii).

100 Wilson Cook, *Report–NT Gas*, January 2011, p. 5.

101 NGR, r. 79(2)(b).

102 NT Gas, Email to AER, *AER.NTGAS.15-18–Update and details on special projects*, 25 February 2011, attachments (confidential), NT Gas, Email to AER, *NT Gas submission on AA revision proposal– revised capex*, 18 March 2011, attachments (confidential).

Table 3.10: Project management fees ($'000, real 2010–11)

Project	Costs	
	Project cost	*Project management fees*
Channel Island meter replacement	218	[c-i-c]
Channel Island Piggability Project	6608	[c-i-c]
Southbound piggability project/ bi-directional pigging project	437	[c-i-c]
Cathodic protection upgrade stage 2	3713	[c-i-c]
Hazardous area assessment and equipment replacement	983	[c-i-c]
Palm Valley filtration and slam shut	273	[c-i-c]
Heat Shrink sleeve replacement	51	[c-i-c]
Below ground station pipeline recoating	4914	[c-i-c]

Source: NT Gas, *Access arrangement submission*, December 2010, attachment C, (confidential), AER analysis.

The AER considers that NT Gas has provided insufficient information to support its proposal for project management fees. The AER considers that in its access arrangement submission in December 2010, NT Gas identified several capex projects that included a project management fee.[103] However, it provided no details or explanation of this fee. In response to the AER's questions on the breakdown of capex costs, NT Gas provided a breakdown of costs for each capex project. Although the breakdown costs included project management fees which the AER has calculated to be [c-i-c] per cent of total costs; it did not provide any further explanation regarding these costs. [104] Therefore due to a lack of substantiation, the AER proposes not to accept NT Gas's proposed project management fees portion of the proposed capex. The AER considers that project management fees related to the proposed forecast capex have not been made on a reasonable basis and do not represent the best forecast or estimate possible under r. 74 of the NGR and that this expenditure does not meet the capex criteria under r. 79 of the NGR.

Cost escalators

The AER's consideration of NT Gas's proposed cost escalators is discussed in chapter 7 of the draft decision. For the reasons outlined in chapter 7, the AER is not satisfied that the proposed cost escalators applied to NT Gas's forecast capex comply with the requirements of r. 79 and r. 74(2) of the NGR. As a result the AER proposes that NT Gas amend its forecast capex by applying the real cost escalators set out in table 7.6 in chapter 7.

103 NT Gas, *Access arrangement submission*, December 2010, attachment C, (confidential).

104 NT Gas, Email to AER, *AER.NTGAS.15-18 - Update and details on special projects*, 25 February 2011, attachments (confidential); NT Gas, Email to AER, *NT Gas submission on AA revision proposal - revised capex*, 18 March 2011, attachments (confidential).

3.6.2.5 Conclusion on capital expenditure

The AER does not consider that NT Gas's forecast capex complies with the requirements under r. 79 of the NGR. That is, it does not represent capex that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice and to achieve the lowest sustainable cost of providing services.

Further, the AER considers that NT Gas's proposed capex is inconsistent with the national gas objective as it does not represent 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 price, quality, safety, reliability and security of supply of natural gas.[105]

The AER also considers that NT Gas's proposed forecast capex does not represent the best forecasts possible in the circumstances.[106]

Table 3.11 shows the capital expenditure proposed by NT Gas compared with the capex which the AER considers satisfy the new capex criteria of the NGR.[107]

Table 3.11: NT Gas's proposed and approved capital expenditure for 2011–2016 ($m, 2010–11, real)

	2010–11	2011–12	2013–14	2014–15	2015–16	Total
Expansion						
NT Gas proposed	0.0	0.0	0.0	0.0	0.0	0.0
AER approved	0.0	0.0	0.0	0.0	0.0	0.0
Replacement						
NT Gas proposed	8.6	1.4	1.1	1.1	1.1	13.3
AER approved	8.1	1.4	1.1	1.1	1.1	12.8
Non-systems						
NT Gas proposed	0.1	0.1	0.4	0.1	0.3	1.1
AER approved	0.1	0.1	0.4	0.1	0.	1.1
Total capital expenditure						
NT Gas proposed	8.7	1.5	1.5	1.2	1.4	14.4
AER approved	8.2	1.5	1.5	1.2	1.4	13.9

Source: NT Gas, *Access arrangement submission*, December 2010, p. 83; AER analysis.

105 NGL, s. 23.

106 NGR, r. 74(2).

107 NGR, r. 79.

Therefore, the AER is proposing that NT Gas is required to amend its access arrangement proposal as outlined in amendment 3.3.

3.6.2.6 Capital contributions

NT Gas has not proposed any non-conforming capital contributions for the access arrangement period.[108] NT Gas anticipates that all capex will be conforming capex. However, NT Gas has noted that where capital contributions are made, they are treated as revenue in the year in which they are made.[109]

The AER considers that this is consistent with r. 82(3) of the NGR. Therefore the AER is not proposing that NT Gas amend its access arrangement proposal for capital contributions.

3.6.2.7 Depreciation

The AER's assessment of NT Gas's forecast depreciation allowance is set out in chapter 4 of the draft decision. Table 3.12 reproduces the conclusions from that chapter.

Table 3.12: AER approved depreciation for the access arrangement period ($'000, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Straight line depreciation	6.0	5.5	5.7	5.9	3.5
Inflationary gain	2.5	2.6	2.6	2.6	2.5
Regulatory depreciation	3.5	2.9	3.1	3.3	0.9

Source: AER analysis

The AER is proposing NT Gas amend its forecast depreciation as outlined in amendment 4.3.

108 NT Gas, *Access arrangement submission*, December 2010, p. 93.

109 NT Gas, *Access arrangement*, December 2010, p. 10.

3.6.2.8 Forecast disposals

NT Gas has submitted that it does not propose any disposals in the access arrangement period.[110] The AER accepts NT Gas's proposal that no disposals are forecast in the projected capital base for the access arrangement period. In doing so the AER acknowledges the opening capital base for access arrangement period commencing 1 July 2016 would be net of the value of any assets disposed of during the access arrangement period.

3.6.2.9 Adjustment to the capital base for inflation

NT Gas used a forecast inflation rate of 2.5 per cent in its modelling. The AER's consideration of NT Gas's approach to estimating expected inflation is discussed in chapter 5 of the draft decision. For reasons discussed in chapter 5, the AER uses a geometric average comprised of the RBA's most up to date short-term inflation forecasts and the target range mid-point of 2.5 per cent to estimate an inflation rate of 2.57 per cent over a 10 year period for the access arrangement period. The AER therefore accepts the proposed forecast inflation rate used by NT Gas. However, the AER notes that the forecast inflation amount will be updated for the final decision based on most up to date information.

3.6.2.10 Summary for projected capital base

The AER has considered the components of NT Gas's proposed projected capital base. Given the amendments required to NT Gas's proposed capex, forecast depreciation and the adjustment of the capital base for inflation, the AER considers that NT Gas's projected capital base does not comply with r. 74(2) and r. 78 of the NGR. The AER proposes that NT Gas amend its access arrangement proposal as outlined in amendment 3.4.

3.6.3 Calculation of the opening capital base at the next access arrangement period

With regard to r. 90 of the NGR, NT Gas has proposed that a forecast depreciation approach to be used to roll forward the capital base at the next access arrangement review.[111]

A forecast depreciation method has been used historically under the previous Code and the AER has approved such an approach in its decisions for Jemena Gas Networks, Country Energy Gas Networks and the ActewAGL Gas Networks.[112] This approach is also consistent with the approach outlined in the AER's Access Arrangement Guideline (AAG).[113]

110 NT Gas, *Access arrangement submission*, December 2010, p. 95.

111 NT Gas, *Access arrangement*, December 2010, p. 11

112 AER, *Final decision: Jemena Gas Networks access arrangement proposal for the NSW gas networks*, June 2010 (AER, *Final decision–JGN*, June 2010.), AER, *Final decision: Country Energy Gas Pty Ltd access arrangement proposal for the Wagga Wagga natural gas distribution network*, March 2010 (AER, *Final decision–Country Energy*, March 2010.) and AER, *Final Decision: ActewAGL Distribution access arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network*, March 2010.

The AER accepts NT Gas's proposed forecast depreciation method and considers that a forecast depreciation method should be used to establish NT Gas's opening capital base for the access arrangement period commencing 1 July 2016.

3.6.4 Other access arrangement proposal provisions relevant to the capital base

3.6.4.1 Capital redundancy policy

Section 3.6.1.4 discusses NT Gas's proposal and the AER's considerations regarding a capital redundancy policy.

3.7 Conclusion

Opening capital base

The AER does not propose to approve the opening capital base proposed by NT Gas for the access arrangement period as it does not comply with r.77(2)(b) of the NGR and requires NT Gas to make amendments 3.1 to 3.2 set out below.

Projected capital base

The AER does not propose to approve the projected capital base proposed by NT Gas as it does not comply with r. 78 of the NGR and proposes that NT Gas make amendments 3.3 to 3.4 as set out below.

Opening capital base for the access arrangement period

The AER approves the proposed estimation of depreciation on the basis of forecast capex for establishing the opening capital base for the next access arrangement period as this complies with r. 90 of the NGR.

Other provisions of the access arrangement proposal

The AER considers that the proposed treatment of non-conforming capex is consistent with rr. 81–84 of the NGR.

3.8 Required amendments

Before the proposed access arrangement and access arrangement information can be accepted, NT Gas must make the following amendments:

Amendment 3.1: amend the access arrangement information to:

- delete Table 3.8 and replace it with the following, and make all other necessary changes so as to be consistent with the following:

Table 3.13: Opening capital base for the earlier access arrangement period ($'000, nominal

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11
Opening capital base	228479.1	216156.2	203509.9	189126.7	171092.0	152128.3	138472.9	129320.0	117284.5	105136.9
plus net capex	224.8	393.6	3040.3	396.0	516.9	330.0	740.0	597.4	692.9	5668.9
plus reused redundant assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
less depreciation	19262.6	20477.2	21456.2	22893.1	24584.4	17691.0	15766.5	15822.1	16227.7	16512.9
plus indexation	6714.9	7437.3	4032.8	4462.4	5103.8	3705.6	5873.5	3189.1	3387.3	2702.0
Closing capital base	216156.2	203509.9	189126.7	171092.0	152128.3	138472.9	129320.0	117284.5	105136.9	96994.9

Amendment 3.2: amend the access arrangement information to:

- delete Table 2.1 and replace it with the following, and make all other necessary changes so as to be consistent with the following:

Table 3.14; Capital expenditure by asset class over the earlier access arrangement period ($'000, 2010–11)

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	Total
Pipeline	22	32	0	0	0	150	0	261	370	2814	3648
Compression	0	0	0	0	0	0	0	0	0	0	0
Meter stations	0	164	507	122	0	0	0	4	116	2190	3103
SCADA & Communications	2	2	2924	89	266	59	4	105	13	0	3465
Operation & Management Facilities	251	274	124	244	302	147	750	246	188	417	2943
Building	0	0	0	0	0	0	0	0	0	0	0
Total	275	471	3555	455	567	356	753	616	687	5422	13158

Amendment 3.3: amend the access arrangement information to:

- delete Table 3.1 and replace it with the following, and make all other necessary changes so as to be consistent with the following:

Table 3.15: Forecast capital expenditure by asset class over the access arrangement period ($m, 2010–11)

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Pipeline	7.4	0.9	0.9	0.8	0.9	11.0
Compression	0.0	0.0	0.0	0.0	0.0	0.0
Meter Stations	0.6	0.1	0.0	0.1	0.0	0.8
SCADA & Communications	0.1	0.3	0.5	0.1	0.4	1.4
Operation & Management facilities	0.1	0.1	0.1	0.1	0.1	0.6
Building	0.0	0.0	0.0	0.0	0.0	0.0
Total	8.2	1.5	1.5	1.2	1.4	13.9

Amendment 3.4: amend the access arrangement information to:

- delete Table 3.7 and replace it with the following, and make all other necessary changes so as to be consistent with the following:

Table 3.16: Projected capital base for the access arrangement period ($m, real 2010–11)

	2011–12	2012–13	2013–14	2014–15	2015–16
Opening capital base	99.5	104.9	103.6	102.2	100.2
plus forecast capex	8.7	1.6	1.7	1.4	1.6
less regulatory depreciation	3.5	2.9	3.1	3.3	0.9
less forecast disposals	0.0	0.0	0.0	0.0	0.0
less forecast redundant assets	0.0	0.0	0.0	0.0	0.0
Closing capital base	104.7	103.7	102.3	100.3	100.9

4 Depreciation

Depreciation over the earlier access arrangement period is one of the determinants of the opening capital base. Depreciation over an access arrangement period is reflected in total revenue in two ways. First it is a component of the projected capital base, and second, it is a separate depreciation building block.

NT Gas's depreciation schedule requires amendments to the remaining lives and opening asset values for operations & management facilities and buildings. The AER accepts NT Gas's proposed standard lives for the access arrangement period. The AER considers the proposed standard lives to be consistent with the expected economic life of the assets.

The AER accepts NT Gas's proposal to split buildings from operating & management (O&M) facilities as appropriate given the different economic lives of these assets. However, the AER does not accept that this split should only be applied going forward. The AER requires that $3.94 million from the O&M facilities asset class be included in the buildings asset class as at 1 July 2011 to reflect the best estimate of the value of buildings at this date.

The AER does not consider the method used by NT Gas to calculate the remaining lives for pipeline, compression, meter station and SCADA assets, allows for the depreciation over their economic life. The method applied does not account for depreciation of capital expenditure (capex) during the earlier access arrangement period. That is the calculation of weighted average remaining lives does not apply the appropriate weight, based on the residual value of the initial capital base (ICB) and capex. Therefore, the AER is not satisfied that the depreciation schedule is consistent with the depreciation criteria under r. 89(1)(b) of the NGR, and has recalculated the remaining asset lives.

Further, the AER does not accept NT Gas's proposed forecast depreciation allowance. The AER calculates a total of $13.7 million in straight line depreciation for the access arrangement period. This total reflects the various adjustments to the capital base made by the AER over the access arrangement period.

4.1 Introduction

This chapter sets out the AER's consideration of NT Gas's proposed depreciation schedule and asset lives for the access arrangement period against the requirements of the NGR.

4.2 Regulatory requirements

NT Gas is required to provide a depreciation schedule that sets out the basis on which the assets constituting the capital base are to be depreciated for determining reference tariffs (r. 88(1) of the NGR). The schedule may consist of a number of separate schedules, each relating to an asset or particular asset classes (r. 88(2) of the NGR).

Rule 89(1) of the NGR provides that the depreciation schedule should be designed:

> (a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

> (b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and
>
> (c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or particular group of assets; and
>
> (d) so that (subject to rules about capital redundancy), an asset is depreciated only once (i.e. the amount by which an asset is depreciated over its economic life does not exceed the value of the asset as at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and
>
> (e) so as to allow the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

Rule 89(2) states that compliance with r. 89(1) may involve the deferral of a substantial amount of depreciation. Rule 89 is a limited discretion provision.[114]

Rule 90 of the NGR requires that the access arrangement must contain provisions governing the calculation of depreciation for establishing the opening capital base for the next access arrangement period. The provisions must resolve whether depreciation of the capital base is to be based on forecast or actual capex.

Clause 5(1)(d) of schedule 1 of the NGR, requires the AER, in deciding whether to approve an access arrangement revision proposal from a transitional access arrangement, to take into account the depreciation schedule for the transitional access arrangement under section 8.32 of the Code.[115]

4.3 Access arrangement proposal

NT Gas proposed to use a straight line method of depreciation to estimate depreciation over the access arrangement period.[116] Further, NT Gas proposed that depreciation will be calculated by applying the remaining life of the assets over the opening capital base.[117] Table 4.1 sets out NT Gas's forecast depreciation for the access arrangement period.

114 NGR, r. 40(2). Rule 40(2)) of the NGR provides the AER with discretion to withhold approval to an element of NT Gas's access arrangement proposal governed by r. 89 of the NGR if the AER is satisfied that the proposal does not comply or is not consistent with the applicable requirements or criteria prescribed by this provision.

115 This clause is also relevant if the AER makes its own proposal for revision of a transitional access arrangement under r. 64 of the NGR.

116 NT Gas, *Access arrangement submission*, December 2010, p. xi.

117 NT Gas, *Access arrangement submission*, December 2010, p. 94.

Table 4.1: NT Gas's proposed depreciation for the access arrangement period ($ million, nominal)

	2010–11	2012–13	2013–14	2014–15	2015–16
Regulatory depreciation[a]	7.4	6.7	7.0	7.2	3.7

Source: NT Gas, Acc*ess arrangement information*, December 2010, p. 11.
a: Regulatory depreciation is straight line depreciation less the inflationary gain (negative depreciation) on the capital base.

The forecast depreciation amounts for the access arrangement period are based on the proposed opening capital base value, capex during the access arrangement, and the remaining asset lives and standard asset lives set out in table 4.2. NT Gas proposed that the remaining lives reflect the weighted average remaining life of the assets in each class.[118] The weighted average remaining life method is consistent with approaches applied in recent gas distribution decisions.[119] Table 4.2 only sets out the significant depreciable asset categories in NT Gas's proposed Post-Tax Revenue Model (PTRM).

Table 4.2: NT Gas's proposed standard and remaining asset lives as at 1 July 2011 (years)

Asset Class	Proposed standard lives	Remaining lives
Transmission pipeline	80	58.7
Compressor stations: Rotating equipment Station facilities	30	20.0
Regulation and metering stations Odorising stations	50	31.0
SCADA	15	6.4
Operations & management facilities	10	4.0
Buildings	40	36.0

Source: NT Gas, *Access arrangement information*, December 2010, p. 11.

The method approved in the earlier access arrangement period to calculate depreciation proposed was to depreciate the leased assets based on the expected residual value of those assets as at 30 June 2011.[120] This resulted in a kinked depreciation profile as accelerated depreciation was opted over straight line depreciation and the residual value to be depreciated using the straight line method

118 NT Gas, *Access arrangement information*, December 2010, p. 11.

119 AER, *Draft decision: APT Allgas Energy Limited access arrangement proposal for the QLD gas network*, February 2011, p. 39 (AER, *Draft decision–APT Allgas*, February 2011).

120 Assets that were depreciated in this manner included pipeline and compression assets, which are leased assets under the current access arrangement.

from 1 July 2011.[121] NT Gas has proposed to calculate forecast depreciation over the access arrangement period using the standard straight line method of depreciation.[122]

NT Gas proposed to change the standard asset lives of O&M facilities and buildings approved by the ACCC in the earlier access arrangement. The proposed change to standard lives entails separating out a ‘buildings’ asset class from the O&M facilities asset class. The O&M facilities asset class had a standard life of 65 years under the earlier access arrangement.[123] The proposed change to O&M facilities will better reflect the shorter economic lives of assets such as IT equipment and building fit out expenditure.[124]

NT Gas’s proposed forecast depreciation allowance includes a significant reduction in depreciation in 2015–16. The reduction is caused by the change in remaining life of the O&M facilities asset class to 4 years, which results in the opening value being fully depreciated by the end 2014–15.

NT Gas proposed that the depreciation schedule for establishing the opening capital base as at 1 July 2016 would be based on forecast capex.[125]

4.4 Submissions

The Northern Territory Major Energy Users (NTMEU) submitted that the depreciation rate should be adjusted to reflect the extension of the need for services of the AGP.[126]

4.5 AER’s consideration

NT Gas’s proposed method to calculating the depreciation allowance requires amendments to the depreciation schedule. The amendments required include changes to the opening value of O&M facilities and buildings asset classes as at 1 July 2011, and the method of calculating the remaining lives. The AER accepts the standard lives of assets proposed by NT Gas. In assessing the depreciation schedule proposed by NT Gas, the AER has considered the following:

- depreciation approach
- asset lives, used to determine the depreciation rate
- the opening value of buildings as at 1 July 2011
- forecast depreciation allowance.

121 ACCC, *Final decision–NT Gas*, December 2002, p.60–67.

122 NT Gas, *Access arrangement submission*, December 2010, p. xi.

123 NT Gas, *Access arrangement submission*, December 2010, p. 94.

124 NT Gas, *Access arrangement submission*, December 2010, p. 80.

125 NT Gas, *Access arrangement proposal*, December 2010, p. 11.

126 NTMEU, *Submission to the AER*, February 2011, pp.14–15.

4.5.1 Depreciation approach

The AER considers that NT Gas's use of the straight line depreciation method is consistent with r. 89(1)(a) of the NGR. The ACCC approved accelerated depreciation over the earlier access arrangement period to address uncertainty about the pipeline's expected economic life and the risk of asset stranding.[127] However, with the connection of new gas sources to the pipeline this risk has reduced. NT Gas proposed the straight line method, which leads to relatively smooth price changes over time. The AER considers the straight line method promotes efficient growth in the market for reference services.

The AER accepts the proposed method of using forecast depreciation to establish the opening capital base at the start of the next access arrangement period under r.90 of the NGR. This approach is consistent with all other AER gas decisions to date.[128]

4.5.2 Asset lives

The depreciation schedule reflects the asset lives of the various assets used to provide the reference services. There are two types of asset lives:

- the standard asset lives to be applied to new assets; and
- the remaining asset lives of existing assets.

4.5.2.1 Standard asset lives

The AER considers that consistency in the economic asset lives across access arrangement periods will ensure that reference tariffs vary over time in a way that promotes efficient growth in the market for reference services.[129] However, the AER is mindful that r. 89(1)(c) of the NGR allows (as far as reasonably practical) for adjustment to the depreciation schedule so as to reflect changes to expected economic lives.

Table 4.3 shows the standard asset lives in the earlier access arrangement period and the access arrangement period. NT Gas proposed a new asset class of 'buildings' with a standard life of 40 years, and to change the 'O&M facilities' standard life to 10 years.[130]

Table 4.3: NT Gas's assessment of standard asset lives (years)

Asset Class	Earlier access arrangement	NT Gas proposed
Pipeline	80	80

127 ACCC, *Final decision–NT Gas*, December 2002, p. 67.

128 AER, *Final decision–JGN*, June 2010, p.72; AER, *Draft decision: Envestra Ltd access arrangement proposal for the Qld gas network*, February 2011, p 43 (AER, *Draft decision–Envestra's Qld network*, February 2011); AER, *Draft decision: Envestra Ltd access arrangement proposal for the SA gas network*, February 2011, p. 49 (AER, *Draft decision–Envestra's SA network*, February 2011); AER, Draft decision–APT Allgas, February 2011, p. 32;

129 NGR, r. 89(1)(a).

130 NTMEU, *Submission to the AER*, February 2011, pp.94–95.

Compression	30	30
Meter stations	50	50
SCADA and communications	15	15
Operation and management facilities	65	10
Buildings	NA	40

Source: NT Gas, *Access arrangement submission*, December 2010, p. 171, attachment E–1 (confidential), NT Gas, *Access arrangement submission*, December 2010, p. 171, attachment E–3 (confidential).

The AER accepts NT Gas's proposal to separate buildings from O&M facilities as the economic lives of the assets are significantly different. The AER also accepts the proposed standard lives for O&M facilities and buildings. The new standard life of 10 years for O&M facilities reflects the composition of assets that form this asset class as these types of assets generally have shorter economic lives than buildings. The standard lives of buildings and O&M facilities as proposed by NT Gas are consistent with the standard lives approved by the AER in previous decisions.[131] Accordingly, the AER has accepted the standard lives for these assets as proposed by NT Gas.

The standard asset lives as proposed for other asset classes are consistent with the standard lives used in the earlier access arrangement period. The AER considers that these lives remain appropriate and are consistent with r. 89(1)(b) of the NGR that requires assets to be depreciated over their economic life. Therefore, the AER also accepts the standard lives for these assets as proposed by NT Gas.

4.5.2.2 Remaining asset lives

The AER considers that NT Gas's method to calculate the remaining lives of certain asset classes means they are not depreciated over their economic lives as required by r. 89(1)(b) of the NGR.

NT Gas adopted a weighted average method to calculate the remaining asset lives as at 1 July 2011 for pipelines, compression, meter stations and SCADA.[132] However, the actual calculation applied does not account for depreciation of capex during the earlier access arrangement period. Therefore, the calculation of the weighted average remaining lives does not apply the appropriate weight based on the residual value of the initial capital base and capex. The AER considers that the method used resulted in incorrect estimates of remaining asset lives. Besides this methodological error, the AER identifies two other matters that also impact on the remaining assets' lives proposed by NT Gas, namely:

- As discussed in chapter 3 of the draft decision, the AER has reduced the forecast capex for 2010–11 for pipelines and meter stations. This reduces the weighting of 2010–11 in the remaining life calculation

131 AER's previous decisions with comparable standard lives include Jemena Gas Networks, APT Allgas and Envestra, for O&M facilities of 10 years, and Ergon, Energex and ETSA Utilities for buildings of 40 years.

132 NT Gas, *Access arrangement submission*, December 2010, p. 171, Attachment E-1 (confidential)

- NT Gas had incorrectly calculated the remaining life of meter stations capex. NT Gas used a standard life of 35 years instead of the approved standard life of the 50 years.

While the AER does not accept the approach used to calculate the remaining asset lives, the AER found that the remaining asset lives for compression and SCADA do not change to one decimal point if the appropriate approach is adopted. Accordingly, these remaining asset lives do not require adjustment. However, the AER considers the remaining asset lives proposed by NT Gas for pipelines and meter stations should be amended. The AER considers the remaining asset lives proposed by NT Gas for pipelines and meter stations to be inconsistent with r. 89(1)(b) of the NGR and requires NT Gas to make amendment 4.2.

NT Gas used a separate approach to estimate the remaining lives of the O&M facilities and buildings asset classes resulting from the proposal to separate buildings from the O&M facilities asset class.[133] The data available limits the ability of the service provider and the AER to provide an accurate value of the buildings asset class from the valuation date of the initial capital base. Based on the available data, the AER considers the methodology employed by NT Gas to construct the buildings asset class provides a reasonable estimate of the remaining asset lives of each of these assets and is therefore consistent with r. 89(1)(b) of the NGR.

A comparison of opening asset values and remaining lives as at 1 July 2011 proposed by NT Gas and the AER's calculations are set out in table 4.4.

Table 4.4 Comparison of NT Gas opening asset values and remaining lives ($ million nominal)

Asset class	NT Gas asset value	NT Gas remaining life (years)	AER asset value	AER remaining life (years)
Pipeline	68.9	58.7	62.0	54.8
Compression	7.3	20.0	7.2	20.0
Meter stations	16.1	31.0	7.9	33.4
SCADA and communications	6.0	6.4	6.0	6.4
Operation and management facilities	13.1	4.0	9.2	4.0
Building	0	36.0	3.9	36.0

Source: NT Gas, *Access arrangement submission*, December 2010, p. 94; NT Gas, *Access arrangement submission*, December 2010, p. 171; NT Gas, *Access arrangement submission*, December 2010, attachment E–3, (confidential); AER analysis.

133 NT Gas, *Access arrangement submission*, December 2010, p.80.

The ACCC decision to accelerate depreciation was partially based on the expectation that the economic life of the pipeline was considered to approximate that of the probable reserves in the Amadeus Basin.[134] NTMEU submitted that the expected economic life of NT Gas assets is now longer given the discovery and development of a new source of gas.[135] The effect of the longer expected economic life of the pipeline and accelerated depreciation is that the value of pipeline assets are relatively low compared to its remaining life. This results in a lower return of capital and lower return on capital to investors.[136]

The NTMEU submission raised concerns over the rate of depreciation of assets comprising the opening asset base. The AER's analysis of the proposed depreciation schedule resulted in amendments to the calculation of remaining lives. The change in methodology to calculate the remaining lives ensures that each class of assets are depreciated over their economic life is consistent with r. 89(1) of the NGR. Therefore, the AER requires NT Gas to makes the changes to address amendment 4.2.

4.5.3 Value of buildings as at 1 July 2011

The AER accepts NT Gas's proposal to separate O&M facilities and buildings into individual asset classes going forward. However, the AER has concerns as to the allocation of existing assets across these two classes. In particular, the AER observes that NT Gas had proposed a remaining asset life for buildings of 36 years compared to the standard life of 40 years, but did not attribute any opening value to buildings asset class.[137]

In response to enquiries from the AER, NT Gas submitted that it proposes to apply the asset classification of buildings going forward, with only new assets added to this asset class.[138] Nonetheless, NT Gas also submitted that, if the value of buildings were to be separated from O&M facilities as at 1 July 2011, it would estimate that about 30 per cent of the value of O& M facilities ($13.16 million) would be related to buildings. This would mean buildings would have an opening asset value of $3.94 million as at 1 July 2011.[139]

The AER does not consider the inclusion of the residual value of buildings in the O&M facilities asset class to be appropriate. The remaining life of O&M facilities of four years is not considered reflective of the remaining life of buildings in this asset class. The AER does not consider that including buildings with O&M facilities that have a remaining asset life of 4 years satisfies the criteria prescribed under r. 89(1) of the NGR.[140] Thus, while the AER accepts the remaining lives proposed by NT Gas as reasonable, it requires that the value of buildings as at 1 July 2011 to be separated from O&M facilities.[141] Based on information provided by NT Gas, the opening value

134 ACCC, *Final decision–NT Gas*, December 2002, p. 65.

135 NTMEU, *Submission to the AER*, February 2011, p. 8.

136 NTMEU, *Submission to the AER*, February 2011, p. 8.

137 NT Gas, *Access arrangement submission*, December 2010, attachment E–3 (confidential).

138 NT Gas, Email to AER, *Re. AER.NTGAS.31*, 23 February 2011, pp. 6–8

139 The ratio was derived from an estimate of the amount of buildings that comprised the initial capital base as at 1 July 2001 and the level of capex between 'buildings' and 'Other O&M facilities' over the earlier access arrangement period.

140 NGR, r. 89(1)(b).

141 NGR, r. 40(2).

of buildings should be $3.94 million, while O&M facilities should be amended to $9.2 million. As a consequence, the AER requires NT Gas to make amendment 4.1.

4.5.4 Forecast depreciation

Due to the changes in the opening values of buildings and O&M facilities noted above and changes to the capital base noted in chapter 3 of the draft decision, the AER does not consider the depreciation schedule proposed by NT Gas satisfies the criteria prescribed under r. 89(1) of the NGR. Accordingly the AER has recalculated the forecast depreciation for the access arrangement period. This amended forecast is shown in table 4.5.

Table 4.5: AER's draft decision of forecast depreciation for the access arrangement period ($'000, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Straight line depreciation	6.0	5.5	5.7	5.9	3.5
Inflationary gain	2.5	2.6	2.6	2.6	2.5
Regulatory depreciation	3.5	2.9	3.1	3.3	0.9

Source: AER analysis.

Regulatory depreciation is straight line depreciation net of the inflationary increase in the capital base for each year. As discussed in chapter 5 of the draft decision, the forecast inflation has been set at 2.57 per cent per annum for each year of the access arrangement period. This inflation forecast will be updated for the final decision. The AER requires NT Gas to makes all changes necessary to comply with amendment 4.3.

NT Gas's depreciation schedule is consistent with r. 89(d) of the NGR that requires each asset is depreciated only once. No deferral of depreciation under r. 89(2) of the NGR is required in the present circumstances.

4.6 Conclusion

The AER accepts the depreciation method and standard asset lives proposed by NT Gas. The AER also accepts the proposed method for rolling forward the capital base for the next access arrangement period under r. 90 of the NGR. However, the AER requires amendments to the opening values of buildings and O&M facilities, and the remaining asset lives. The AER considers that the remaining lives calculated by NT Gas and the AER are similar, however the method applied by NT Gas to derive the remaining asset lives does not meet the depreciation criteria under r 89(1) of the NGR. Rule 40(2) of the NGR requires the AER to exercise its discretion to correct an inconsistency between the proposed depreciation schedule and the depreciation criteria. In addition, due to changes in the capital base discussed in chapter 3 of the draft decision, the forecast depreciation allowance for the access arrangement period has been revised. Given these required changes, the AER does not approve the depreciation schedule proposed by NT Gas for the access arrangement period as it does not comply with r. 89(1) of the NGR.

4.7 Required amendments

Before its access arrangement proposal can be accepted, NT Gas must make the following amendments:

Amendment 4.1: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of the revised opening asset values for building and O&M facilities as discussed in section 4.5.3 of this draft decision and shown in table 4.4.

Amendment 4.2: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of the revised to the remaining lives and asset values for the asset classes of pipelines and meter stations as discussed in section 4.5.2.2 and shown in table 4.4.

Amendment 4.3: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of revised forecast depreciation allowance in table 4.5 of this draft decision.

5 Rate of return

The AER has rejected NT Gas's proposed rate of return of 11.42 per cent, as it is not commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services. The AER is of the view that the rate of return of 9.72 per cent is appropriate for the benchmark service provider. The AER considers that NT Gas's proposed rate of return is derived using parameter estimates that are inappropriate. The AER has undertaken a number of reasonableness checks to confirm the rate of return it has determined.

Incorporated in this decision are the AER's considerations that values of the equity beta and MRP below those proposed by NT Gas are reflective of the risks involved in providing reference services under prevailing market conditions. Similarly, the AER has also rejected NT Gas's proposed method of setting the debt risk premium, instead finding a combination of estimates derived from Bloomberg and the APA Group's BBB rated bond provide a debt risk premium which is sufficient to cover at least the efficient cost of debt.

The AER has calculated a rate of return of 9.72 per cent. This reflects market based parameters (risk free rate and debt margin) estimated over the averaging period of 20 business days ending 1 April 2011.

5.1 Introduction

This chapter sets out the AER's estimate of an efficient benchmark rate of return on capital for NT Gas over the access arrangement period. The key issues considered include the determination of the equity beta to be applied in the context of the capital asset pricing model (CAPM) as well as the debt risk premium.

The AER's consideration of the corporate taxation allowance, including the value of imputation credits (gamma), is set out in chapter 6.

5.2 Regulatory requirements

Rule 72(1)(g) of the NGR requires that the access arrangement information for a full access arrangement proposal must include the proposed rate of return, the assumptions on which the rate of return is calculated and a demonstration of how it is calculated.

Rule 74 of the NGR requires that any forecast or estimate included in the access arrangement information be supported by a statement of the basis of that forecast or estimate, be arrived at on a reasonable basis, and represent the best forecast possible in the circumstances.

Rule 87(1) of the NGR requires that the rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.

Rule 87(2) of the NGR requires that in determining a rate of return on capital, it will be assumed that the service provider meets benchmark levels of efficiency, uses a financing structure that meets benchmark standards—as to gearing and other financial parameters—for a going concern, and reflects in other respects best practice. Further, a well accepted approach that incorporates the cost of equity and debt is to be used; and a well accepted financial model is to be used. The WACC is given as an example of a well accepted approach, and the CAPM is given as an example of a well accepted financial model.

5.3 Access arrangement proposal

NT Gas proposed a nominal vanilla WACC approach to determine the rate of return on its projected capital base.[142] NT Gas proposed the use of the (standard) Sharpe-Lintner CAPM to determine the cost of equity.[143]

NT Gas included debt raising costs in the cost of debt used to calculate the nominal vanilla WACC. Table 5.1 presents NT Gas's proposed WACC with and without debt raising costs.

142 NT Gas, *Access arrangement submission,* December 2010, p. xi, NT Gas, *Access arrangement information,* December 2010, p. 24. The AER notes that NT Gas labels its WACC approach a 'post-tax nominal WACC' in its access arrangement submission. The label 'nominal vanilla WACC' is used by NT Gas in its access arrangement information, and the formula set out in this document is the nominal vanilla WACC formula.

143 NT Gas, *Access arrangement information,* December 2010, p. 23.

Table 5.1: WACC parameters proposed by NT Gas

WACC Parameter	NT Gas proposal
Nominal risk–free rate (%)	5.48
Inflation (%)	2.50
Equity beta	1.00
Market risk premium (%)	6.50
Debt risk premium (%)	5.46
Debt raising costs[a] (%)	0.108
Gearing (%)	60.00
Gamma[b]	0.20
Cost of equity (%)	11.98
Cost of debt including debt raising costs (%)	11.05
Cost of debt (%)	10.94
Nominal vanilla WACC including debt raising costs (%)	11.42
Nominal vanilla WACC (%)	**11.36**

Source: NT Gas, *Access arrangement submission,* December 2010, p. 115; NT Gas, *Access arrangement Information*, December 2010, p. 24; AER analysis.

a: Debt raising costs are reported as a WACC component in NT Gas's proposal. The AER separately considers an operating allowance for debt raising costs in appendix B of this decision.

b: The AER's consideration of the value of gamma is set out in chapter 3 of the draft decision.

In support of its proposal, NT Gas submitted a report by Synergies Economic Consulting (Synergies).[144] In summary, NT Gas's and Synergies' approaches with respect to individual parameters were as follows:

- Inflation forecast — the 2.5 per cent value proposed was the mid point of the RBA's target band of between 2 and 3 per cent.
- Averaging period and risk free rate — a confidential period was proposed. An indicative risk free rate of 5.48 per cent was calculated using the annualised yield on 10 year Commonwealth Government bonds over a period of 20 business days ending 30 November 2010.
- Gearing ratio — a proportion of 60 per cent was proposed.

144 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline,* December 2010.

- Debt risk premium (DRP) — NT Gas proposed relying on Bloomberg fair value estimates, extrapolated to calculate a premium of 5.46 per cent with respect to a 10 year, BBB+ credit rating benchmark. NT Gas and Synergies stated that it is inappropriate for the AER to give any weight to the recently issued 10 year BBB rated bond of the APA Group in setting the DRP.

- Market risk premium (MRP) — 6.5 per cent is argued to be a conservative estimate given uncertainty about the risk of a further downturn in the global economy, comparisons between the cost of debt and equity, and outcomes of implied volatility analysis.

- Equity beta — a value of 1.0 was proposed given Synergies' view that there is insufficient data available to justify any revision to the value of 1.0 previously adopted for NT Gas by the ACCC. NT Gas highlighted the risk of asset stranding due to depletion of gas reserves.

To support its claims with respect to the overall rate of return and equity beta in particular, Synergies presented analysis which compares the historical difference between the cost of debt and equity, which is greater than that resulting from the AER's recent determinations.

With respect to the MRP, Synergies stated that global market conditions remain unstable and this is likely to affect the level of risk in the Australian market. Synergies stated Officer and Bishop have estimated a forward looking MRP estimate of 7–8 per cent and based on this an MRP of 6.5 per cent is currently likely to be a lower bound.[145]

5.4 Submissions

The Northern Territory Major Energy Users noted the DRP proposed by NT Gas is significantly higher than the margins allowed by the AER recently, which have been decreasing since the global financial crisis (GFC). With respect to the appropriateness of using the APT bond as a benchmark, NTMEU stated that there is an expectation that the higher gearing and lower credit rating of the APA Group with respect to the benchmark would suggest the benchmark cost of debt is lower than that associated with the APT bond.[146]

The NTMEU did not support NT Gas receiving compensation for stranding risk, as the pipeline has already been subjected to significant amounts of accelerated depreciation. Furthermore, the NTMEU considered there would still be a need to use the pipeline to transport gas from Ban Ban Springs to Alice Springs in the event the reserves of the Amadeus Basin are depleted.[147]

Santos Limited and Magellan Petroleum Australia Limited (Santos and Magellan) submitted that the rate of return proposed by NT Gas was inconsistent with regulatory

145 Synergies, *Estimating a WACC for the NT gas transmission pipeline*, December 2010, pp. 69–73. Synergies has not provided the October 2009 report it has referred to. However, there is a more recent update of Officer and Bishop's work dated July 2010. In the first instance, the AER has referred to the July 2010 paper.

146 NTMEU, *Submission to the AER*, February 2011, pp. 53-4.

147 NTMEU, *Submission to the AER*, February 2011, p. 55.

precedent and recent regulatory determinations of the AER. Its recommended values were 10.28 and 9.84 per cent for the cost of equity and debt, respectively and a10.01 per cent post-tax nominal WACC.[148]

Power and Water Corporation (PWC) submitted that the service provider had substantially overstated the appropriate WACC.[149] It provided an expert opinion from Allen Consulting Group (ACG) that recommended 8.83 per cent for the cost of equity and 8.83 per cent for the cost of debt. ACG's recommended WACC estimate is 8.83 per cent.[150]

The Northern Territory Treasury (NT Treasury) submitted that NT Gas's proposed rate of return was higher than warranted. It noted that the sunk costs of the pipeline had largely been recouped under past access arrangements. Further, the NT Treasury submitted that the AGP was uniquely riskless asset compared to other gas pipelines, due to PWC's historical and expected dominant use of the pipeline.[151]

5.5 AER's consideration

The AER has not accepted NT Gas's proposed rate of return. In doing so, and in determining a rate of return it considers best meets the requirements of the NGR, the AER recognises that there is no precise answer that can be determined through the mechanistic application of a mathematical formula or parameter estimates developed in isolation. Parameter values that are unrepresentative of the best estimate commensurate with the market and the risk of providing the reference service would result in an inappropriate rate of return. In determining an appropriate rate of return the AER has reviewed a variety of evidence and arguments, and ultimately exercise its judgment to arrive at an outcome it determines best meets the revenue and pricing principles and the national gas objective. To arrive at this outcome, the AER has compared the rate of return against high level indicators for reasonableness. These indicators suggest that the rate of return chosen by the AER is at least sufficient to meet the objectives and requirements of the NGL and NGR.

The AER's considerations are summarised in the following main sections:

- an evaluation of why the rate of return set by the AER is appropriate
- the market risk premium
- equity beta
- the debt risk premium
- the method of inflation forecast
- the averaging period and risk free rate

148 Santos and Magellan, *Submission to the AER*, February 2011, p.11.

149 PWC, *Submission to the AER*, 14, March 2011, pp. 9–10.

150 The Allen Consulting Group, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation in support of its submission to the AER's access review*, 11 February 2011.

151 NT Treasury, *Submission to the AER*, March 2011, p. 5.

- the gearing (debt to equity) ratio.

Further details on particular matters, including the overall rate of return, equity beta, MRP and DRP are contained in appendix A.

5.5.1 Evaluation of the overall rate of return

This section considers the reasonableness of the overall rate of return resulting from parameters assessed and determined by the AER elsewhere in this chapter. Such a consideration is relevant in considering the adequacy of the rate of return in accordance with s. 24(2) of the NGL which states that a service provider should be provided an opportunity to recover at least its efficient costs. Similarly, such comparisons can be applied to assess the reasonableness of the rate of return proposed by NT Gas.

Recent regulated asset sales and trading ratios suggest that benchmark returns for regulated entities have been at least sufficient (and probably higher than needed) to meet the cost of capital faced by regulated entities. The analysis presented by NT Gas regarding the relationship between the return on equity and debt does not suggest any inadequacy of the overall rate of return set by the AER. These considerations are summarised briefly here, with further details in appendix A.

5.5.1.1 Recent regulated asset sales

Over the past few years, regulated assets have generally been sold at a premium to the regulatory asset base (RAB). The recent purchase of Country Energy's NSW gas network by Envestra is one such example. Envestra purchased the Wagga Wagga gas network at a 25 per cent premium to the 2010 RAB and 19 per cent premium to the 2011 RAB.[152] Other recent sales have been at premiums of between 20 and 119 per cent to the regulated asset base (see table A.1). Similarly, listed regulated assets have been valued by the market at premiums of 15 to 73 per cent over the 2010 RAB (see table A.2).

As supported by Grant Samuel, listed infrastructure entities should theoretically trade at, and be acquired at, 1.0 times the RAB.[153] However, all recent asset sales have been transacted at RAB multiples of greater than one.

A RAB multiple of greater than one is not necessarily conclusive of whether the AER's weighted average cost of capital provides the service provider with an efficient return. For instance, a RAB multiple of higher than one may be justified if the buyer can:

- expect to achieve efficiency gains, reducing operational and capital expenditures below the amounts allowed by the regulator
- increase the service provider's revenues by encouraging demand for regulated services

152 AER, *Final decision–Country Energy*, March 2010; ASX, *Envestra company announcement*, 26 October 2010, viewed 27 January 2011, < http://www.asx.net.au/asxpdf/20101026/pdf/31tcv1nblp4xqc.pdf>

153 Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock & Brown Infrastructure*, 9 October 2009, p. 77.

- benefit from a more efficient tax structure, higher gearing levels, and growth options
- expect to achieve higher returns if regulation is relaxed or
- misjudge the true value of the business.

However, the trading and acquisition premiums have been substantial. Premiums of this magnitude are unlikely to be explained by the factors noted above alone. This suggests that the regulated cost of capital has been at least as high as the actual cost of capital faced by the businesses, and most likely that it has been in excess of the actual cost of capital. Market transactions do not support the view that regulated rates of return result in under compensation with respect to actual required rates of return.

Further, as part of the AER's review of Envestra's access arrangement proposal, the AER has reviewed a number of the broker reports quoted by Envestra's consultant SFG. Through this review the AER is aware that brokers have been discounting regulated utilities cash flows at rates significantly lower than the AER's weighted average cost of capital. The AER considers this is further evidence that the AER's return on capital does not under compensate the service provider.[154]

5.5.1.2 Relationship between return on equity and debt

NT Gas presented analysis which it suggested demonstrated a predictable relationship between the cost of equity and the cost of debt. In particular, it stated that the cost of equity must be at least 4.5 per cent higher than the cost of debt.[155]

The AER does not consider there to be an a priori reason to expect a constant difference between the cost of debt and equity over time. The difference could be the result of the cost of debt recently allowed by the AER being too high. Further, the 4.5 per cent required difference between cost of equity and debt as proposed by NT Gas is over estimated as it is derived using parameters that are not reflective of a regulated utility. In particular:

- the return on equity is based on the All Ordinaries Accumulation index, which has a beta of one, rather than the beta of 0.8 set by the AER
- the return on debt is based on the UBS Australian Composite Index, which is likely to be of a higher credit grade than BBB+ which the AER has determined reflects the rating of a benchmark service provider.

5.5.2 Market risk premium

The MRP is the expected return over the risk-free rate that investors require in order to invest in a well diversified portfolio of riskier assets. The MRP represents the risk premium investors who invest in such a portfolio can expect to earn for bearing only non-diversifiable (systematic) risk. The MRP is common to all assets in the economy and is not specific to an individual asset or business.

154 AER, *Draft decision–Envestra's Qld network*, February 2011, appendix C.1.2.

155 NT Gas, *Access arrangement submission*, December 2010, p. 116, Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 67–68.

The AER accepts NT Gas's proposed use of the CAPM as a well accepted model to estimate its cost of equity. Within the CAPM framework, the MRP is scaled up or down by the equity beta (of a particular asset or business) to reflect the risk premium—over and above the risk-free rate—equity holders would require to hold that particular risky asset or business as part of the investor's diversified portfolio. The MRP is an expected or forward looking parameter within the CAPM. It is the expected return on the market portfolio minus the risk free rate. NT Gas has proposed the use of the yield on 10 year Commonwealth Government Securities (CGS) as the proxy for the risk free rate,[156] which the AER has accepted. To maintain consistency within the CAPM, the MRP must be estimated for a 10 year investment horizon.[157]

The MRP is not observable because it is a forward looking measure. There is a range of evidence that can inform the best estimate of the forward looking 10 year MRP. In previous regulatory decisions the AER has used historical estimates, survey based estimates, and qualitative data on expected market conditions to inform the best estimate. Historical data on realised excess market returns may provide a starting point. Surveys provide information on the expectations and practice of market practitioners. Short term estimates of volatility can provide some information on the expected MRP, but are highly variable. In addition to this, short term estimates are unlikely to reflect a 10 year horizon.

The evidence used to estimate the MRP is imprecise and subject to varied interpretation, a point that is well recognised in academic literature[158] and in reports put forward by regulated entities.[159] As a result, the AER and previous regulators have had regard to a range of indicators, informed by an understanding of the strengths and weaknesses of each method. The available evidence is imprecise and potentially conflicting, which means a degree of judgment is required to determine the MRP that is the best estimate in the circumstances and commensurate with prevailing conditions in the market for funds.[160]

For the purposes of determining the best estimate of the MRP for NT Gas, the AER has considered the national gas objective set out in the NGL. The objective 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 price, quality, safety, reliability and security of supply of natural gas. The AER has also had regard to the revenue and pricing principles in the NGL, which state a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services.[161] The value of the MRP is a highly contentious issue amongst academics and market practitioners

156 NT Gas, *Access arrangement submission*, December 2010, p. 103.

157 The Australian Competition Tribunal also noted the importance of consistency between the term of the risk free rate and the MRP. See Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6.

158 Mehra R. and Prescott E.C., *The equity premium, A puzzle, Journal of Monetary Economics*, 15, 1985, pp. 145–161; Damodoran A., *Equity Risk Premiums (ERP), Determinants, Estimation and Implications*, September 2008, p. 1; Doran J.S., Ronn E.I. and Goldberg R.S., *A simple model for time-varying expected returns on the S&P 500 Index*, August 2005, pp. 2–3.

159 Officer and Bishop, *Market risk premium, a review paper*, August 2008, pp. 3–4; SFG, *The relationship between theta and MRP, Report for Envestra*, 27 September 2010, p. 5.

160 NGR, r. 87(1).

161 NGL, s. 24(2)(a).

and there is no definitive answer as to the value of the unobservable MRP. The AER has used its judgement to balance academic evidence and evidence from a range of other sources to achieve an outcome which balances the objectives set out in the NGL.

5.5.2.1 Previous regulatory practice

In regulatory decisions prior to the AER's WACC review final decision in 2009,[162] the ACCC, the AER and state regulators maintained 6 per cent as the best long term estimate of the MRP in the Australian market. In examining those earlier decisions for the purposes of the WACC review (in particular, considering the MRP previously adopted by various regulators) the AER noted the precedent set in 1998 by the ACCC and the Victorian Office of the Regulator General (ORG).

The ACCC's decision in 1998 was to reject the MRP value of 6.5 per cent proposed by Transmission Pipelines Australia (TPA) for its gas access arrangements and instead use a value of 6 per cent, taking into account the following evidence and considerations:

- TPA's consultant, CSFB, proposed 6.5 per cent given the conventionally accepted value was 6–7 per cent under the classical tax system
- the relatively stable inflationary environment prevailing at the time suggested that the MRP was less than that observed over recent years
- dividend growth model estimates produced by Professor Davis suggested a MRP within the range of 4.5–7 per cent
- the probable range for the MRP is 4.5–7.5 per cent and 6 per cent is a mid-point within that range.[163]

In making its 1998 decision for the Victorian gas distribution businesses, the ORG determined that a value of 6.5 per cent as proposed by the businesses was towards the upper end of the feasible range. However, it considered that 6 per cent was a more reasonable estimate taking into account the following:

- research undertaken by Professor Officer suggested that the mean of historical excess returns was in the range of 6.5 per cent to 7 per cent over the period 1947 to 1991, depending on the specific period over which excess returns were measured
- a direct quote from Officer that he had consistently used an MRP of 6 per cent in his own work, simply on the basis that he believed 6 per cent was consistent with historical evidence
- dividend growth model estimates produced by Davis (however, the ORG cautioned against placing too much weight on these given the sensitivity to assumptions employed)[164]

162 AER, *WACC review final decision*, 1 May 2009.

163 ACCC, *Final decision*, *Access arrangement for Transmission Pipelines Australia and Victorian Energy Networks Corporation*, October 1998, p. 53.

- comments by Davis that historical excess returns calculated over a 30 year period, once adjusted for imputation credits, were in the order of 5.5 to 6 per cent

- comments by Associate Professor Stephen Gray that the generally accepted MRP in the Australian market was in the range of 6 to 7 per cent.[165]

Further studies were commissioned after the ACCC and ORG's gas network decisions which factored into regulators' considerations of the MRP. For example, in 2005, Associate Professor Neville Hathaway produced a report recommending an MRP of 4.5 per cent. Associate Professor Hathaway's estimate was based on a 6 per cent geometric average of historical excess returns for 1875–2005 that was adjusted by 145 basis points to take account of the increase in the price to earnings ratio after 1960.[166] In 2005, Jim Hancock of the South Australian Centre for Economic Studies estimated the historical equity risk premium to be 4.5–5.0 per cent.[167] Hancock's estimate was based on an arithmetic average of 5.5–6.0 per cent for the period 1974–2003 adjusted downwards by 1 per cent to take account of declining discount rates and the large unanticipated initial market response to the introduction of dividend imputation between July and September 1987.[168] Other studies suggesting a MRP greater than 6 per cent should be adopted have also been considered.[169]

Rather than simply adopting the latest estimates presented at the time, regulators carefully considered the various arguments and limitations surrounding the forms of evidence presented to them and used judgment when forming a view of the most appropriate forward looking MRP. Decisions by the ACCC and state regulators regarding point estimates of the MRP consistently chose a value of 6 per cent.

In the WACC review final decision, the AER also considered the best estimate for the forward looking 10 year MRP prior to the onset of the GFC was 6 per cent. This estimate was based on a range of information including historical estimates, survey estimates, cash-flow based measures and past regulatory practice. However, the AER acknowledged the uncertainty in the market at the time of the WACC review final decision. The AER considered one of two scenarios could have explained market conditions at that time:

- The prevailing medium term MRP was above the long term MRP, but would return to the long term MRP over time; or

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164 ORG, *Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd, Draft decision*, May 1998, pp. 211, 212.

165 ORG, *Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd, Final decision*, October 1998, p. 199.

166 Hathaway, *Australian market risk premium*, January 2005, p. 28.

167 Hancock. *The market risk premium for Australian regulatory decisions*, April 2005, p. 13.

168 Hancock, *The market risk premium for Australian regulatory decisions*, April 2005, pp. 11–13.

169 See for example the studies referred to in ESCV, *Electricity Distribution Price Review 2006-10 October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 Final Decision Volume 1 Statement of Purpose and Reasons*, February 2006, pp. 359–361 and ESCV, *Review of Gas Access Arrangements Final Decision*, October 2002, p. 324.

- There had been a structural break in the MRP and the forward looking long term MRP (and consequently also the prevailing) MRP is above the long term MRP that previously prevailed.

Due to the uncertainty about the effects of the GFC on future market conditions the AER departed from the previously adopted forward looking MRP estimate of 6 per cent and increased it to 6.5 per cent.[170] Based largely on the findings of the WACC review, the AER applied an MRP of 6.5 per cent in a number of recent regulatory decisions for gas networks.[171] This was noted by Synergies in its report prepared for NT Gas and by ACG in its report prepared for the Power and Water Corporation.[172] Synergies submitted that current market conditions, and analysis by Officer and Bishop, suggest that 6.5 per cent is likely to be a lower bound estimate of the forward looking MRP. ACG appears to adopt an MRP of 6.5 per cent consistent with the AER's final decision for the Jemena Gas Networks (JGN) access arrangement.[173]

Market conditions since the time of the WACC review have significantly improved and now reflect a lessening of concerns about the potential ongoing impact of the GFC and a much more robust economic and financial markets outlook for Australia. This suggests the uncertainty which justified the AER's departure from the long run MRP value of 6 per cent is no longer a characteristic of prevailing market conditions. In this context the AER has re-examined the various forms of evidence considered at the time of the WACC review to inform its current view of the forward looking 10 year MRP. The AER's analysis is set out below.

5.5.2.2 Historical estimates of the MRP

Historical excess returns represent the additional return that investors could have earned in the past by investing in a diversified portfolio of shares. Although not forward looking, historical excess return estimates have been reviewed under the assumption that investors' expectations of the forward looking MRP are informed by past experience.

Associate Professor John Handley has provided estimates of historical excess returns for three time periods up to 2010, which are outlined in table 5.2. These estimates are arithmetic means and with data available to the end of 2010 provide a range of 6.1–6.6 per cent.[174]

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170 AER, *WACC review final decision*, 1 May 2009, p. 238.

171 AER, *Final decision–JGN*, June 2010, p. 173.

172 Synergies, *Estimating a WACC for the NT gas transmission pipeline*, December 2010, p. 69; ACG, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation*, 11 February 2011, p. 1, 4, 19 (confidential).

173 ACG, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation*, 11 February 2011, p. 1, 4, 19 (confidential).It is not clear whether ACG has considered the value of the MRP since the AER published the Jemena Gas Networks access arrangement final decision because it has not included any analysis of the issue in its report.

174 The reasons for choosing these time periods are outlined in appendix A of the draft decision.

Table 5.2: Historical excess return estimates (assuming an imputation credit utilisation rate of 0.65) (%)

	Historical excess returns	95% confidence interval
1883–2010	6.3	3.4 – 9.2
1937–2010	6.1	1.5 – 10.7
1958–2010	6.6	0.4 – 12.9

Source: Handley, *An estimate of the historical equity risk premium for the period 1883 to 2010*, January 2011, p. 8.

Estimates of average historical excess returns are accompanied by very wide confidence intervals and can also fluctuate considerably with the addition of new observations for each year. This is illustrated in table 5.3.

Table 5.3: Historical excess return estimates (assuming an imputation credit utilisation rate of 0.65) (%)

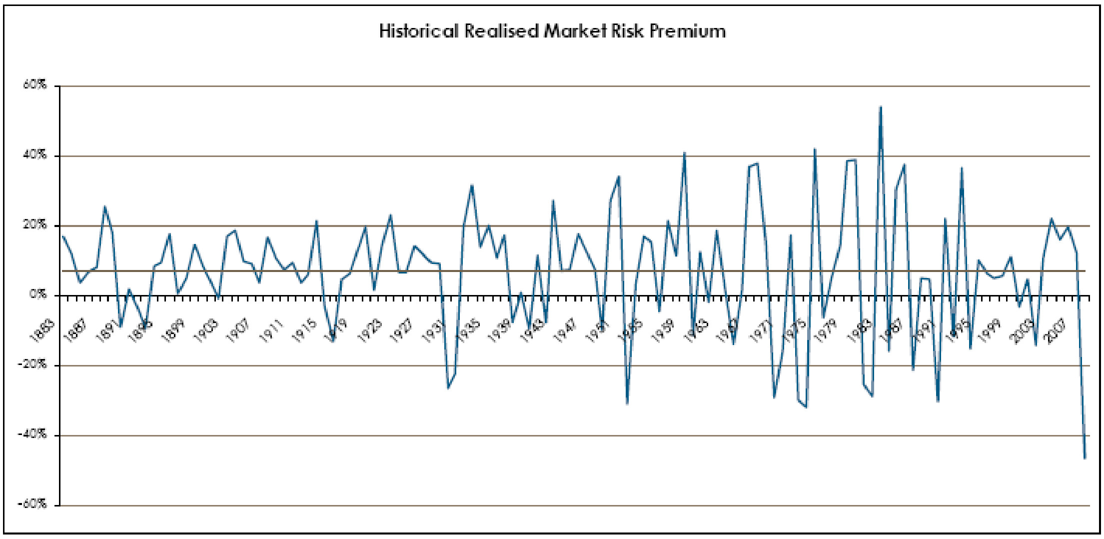
	2005	2007	2008	2009	2010
1883–	6.4	6.6	6.1	6.4	6.3
		(1.4)	(1.5)	(1.5)	(1.5)
1937–	6.1	6.4	5.7	6.1	6.1
		(2.3)	(2.3)	(2.3)	(2.3)
1958–	6.8	7.2	6.2	6.7	6.6
		(3.1)	(3.2)	(3.2)	(3.1)

Source: AER, *WACC review final decision*, 1 May 2009, p. 215; Handley, *Memorandum: Supplement to historical equity risk premium*, 27 November 2008; Handley, *An estimate of the historical equity risk premium for the period 1883 to 2010*, January 2011, p. 8; Brailsford, Handley and Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and finance, vol. 48, pp. 90–93; AER analysis.

Note: The standard errors of the estimates are contained in the parentheses. Figures for 2005 are from Brailsford et al. (2008) and have been adjusted to reflect an assumed imputation credit utilisation rate of 0.65. Estimates have not previously been calculated for 2006, and the AER has not retrospectively calculated figures for 2006.

The reason for the sensitivity of these results to additional years of data is the variability in market returns in any given year. This is illustrated in figure 5.1, which graphs realised historical market returns minus the proxy for the risk free rate.

Figure 5.1: Historical realised excess market returns 1883–2008



Source: Officer and Bishop, *Market risk premium, further comments*, January 2009, p. 4.

The historical estimates summarised in table 5.4 would suggest a forward looking MRP of 6.1–6.6 per cent for the period ending 2010. These values are, however, not inconsistent with the estimates prior to the GFC. Consistent with past regulatory practice the AER does not consider historical estimates of excess market returns should be applied mechanistically to give a point estimate of the MRP or a restrictive range for point estimates of the MRP because:

- the estimates are subject to wide confidence intervals and as a result there is low statistical precision in the estimates[175]
- it could result in potentially significant changes to the MRP on the basis of what may be statistical noise, leading to investment uncertainty
- while this information would be taken into account by investors, their expectations of the long run forward looking MRP are unlikely to change annually in response to the latest historical estimates of the type calculated by Handley.

The historical excess return estimates outlined above are arithmetic means. Arithmetic means are more appropriate when the excess return in each year is an independent observation in a statistical sense. In contrast, geometric means are more appropriate when yearly returns are related to each other over time (for example, if the return is compounded and accumulates over a certain holding period). As long as returns vary over time, a geometric mean will be less than an arithmetic mean. The greater the volatility in returns, the greater the difference between arithmetic and geometric means.

175 The AER notes that expectations about market risk are likely to differ at any point in time based on different economic and financial market circumstances. This in itself makes estimates of the actual MRP through time very difficult to estimate with accuracy.

In the WACC review, the AER noted that Blume, as well as Dimson, Marsh and Staunton have proposed methods that could be used to calculate an expected MRP using a weighted average of arithmetic and geometric means.[176] If historical excess returns are estimated as geometric means, Associate Professor Handley's latest estimates of the MRP range from 4.1–4.9 per cent. Table 5.4 illustrates the difference between the historical excess returns estimated as geometric means or arithmetic means. The significant difference between these two estimates further demonstrates the variability of excess returns over time.

Table 5.4: Historical excess returns estimated using geometric means and arithmetic means (assuming an imputation credit utilisation rate of 0.65) (%)

	Historical excess returns (geometric means)	Historical excess returns (arithmetic means)
1883–2010	4.9	6.3
1937–2010	4.1	6.1
1958–2010	4.1	6.6

Source: Handley, *An estimate of the historical equity risk premium for the period 1883 to 2010*, January 2011, p. 8.

There is already a low degree of precision in historical estimates of excess returns and using a weighted average of geometric and arithmetic means adds a further degree of complexity that may not add any greater degree of precision. Therefore, rather than using a complex weighted average approach, the AER considers that arithmetic averages should be interpreted with the understanding that they may overstate the expected forward looking 10 year MRP.[177]

5.5.2.3 Historical estimates and the assumed value of imputation credits

Officer and Bishop use a 7 per cent long term MRP estimate in their 'glide path' analysis (which is examined further below). Officer and Bishop's 7 per cent long term MRP estimate is based on historical excess returns data up to 2008.[178] Officer and Bishop have previously stated the main reason for adopting an MRP of 7 per cent over an MRP of 6 per cent was due to the value of imputation credits, which they stated had not been considered by Australian regulators in the past.[179] This issue was considered in detail during the WACC review, where the AER noted:

- previous regulators had taken into account the value of imputation credits in the process of determining 6 per cent as the best estimate of the MRP.[180]
- within the Officer WACC framework, it is conceptually valid to take into account the value of distributed imputation credits when estimating historical excess

176 AER, *WACC review final decision*, 1 May 2010, pp. 198–199.

177 The difference between geometric and arithmetic means is discussed further in appendix A.

178 Officer and Bishop, *Market Risk Premium, Estimate for January 2010–June 2014, Prepared for WestNet Energy*, December 2009, pp. 9–10

179 Officer and Bishop, *Market risk premium, a review paper*, August 2008, p. 1.

180 AER, *WACC review final decision*, 1 May 2009, pp. 182–184.

returns by grossing up excess returns after 1987 for the assumed utilisation rate (theta) of imputation credits.[181]

The AER explicitly incorporated the value of imputation credits in its estimates of historical excess returns, which at the time of the explanatory statement for the WACC review produced a range of 5.9–6.5 per cent.[182] At the time of the WACC review final decision, the range for historical estimates was 5.7–6.2 per cent.[183] Both of these ranges were 'grossed-up' using a utilisation rate for imputation credits of 0.65. Neither of these ranges supports a MRP estimate of 7 per cent.[184]

The AER has considered historical excess returns explicitly 'grossed-up' for a utilisation rate of 0.65, consistent with the utilisation rate estimate adopted by the AER for estimating gamma. The excess return estimates have first been estimated by Associate Professor Handley and then adjusted for an assumed value of imputation credits. Therefore, the historical excess return estimates considered by the AER should be 'grossed-up' for the utilisation rate for imputation credits used by the AER for estimating gamma.[185] The latest historical excess return estimates 'grossed-up' for a utilisation rate for imputation credits of 0.2 provide a range of 5.8–6.3 per cent.[186] While the AER has maintained that 0.65 is an appropriate value for the utilisation rate, it highlights that changes in this value may affect the interpretation of historical excess returns when setting the MRP.

5.5.2.4 Implied volatility and Officer and Bishop's glide path approach

Synergies submitted that Officer and Bishop have estimated the forward looking MRP to be between 7 and 8 per cent.[187] Officer and Bishop submitted that an MRP of 8 per cent is appropriate over a five year period to 2016 based on a 'glide path' approach:

- Officer and Bishop estimated the volatility implied from the Black-Scholes option-pricing formula for 12-month ASX200 index call options to be 11.9 per cent. This estimate assumed a market risk per unit of option implied volatility of 0.5. It is a 1-year estimate of the MRP.

- Officer and Bishop then estimated the geometric average MRP over five years assuming the MRP would revert from 11.9 per cent in 2011 to a long run estimate of 7 per cent within a five year period. [188]

181 AER, *WACC review final decision*, 1 May 2009, p. 209.

182 AER, *Explanatory statement, WACC review*, August 2008, p. 170.

183 AER, *WACC review final decision*, 1 May 2009, p. 209.

184 Officer and Bishop also use arithmetic means and therefore may also overstate the expected forward looking 10 year MRP to some extent. Officer and Bishop's estimate uses the same data as Associate Professor Handley for the period 1883–1958.

185 In this regard, the AER notes the utilisation rate for imputation credits estimated by the AER is under consideration by the Australian Competition Tribunal.

186 Handley, *An estimate of the historical equity risk premium for the period 1883–2010*, January 2011, p. 6.

187 Synergies, *Synergies, Estimating a WACC for the NT gas transmission pipeline*, December 2010, pp. 71–72.

188 Officer and Bishop, *Comments on the AER draft distribution determination for Victorian electricity distribution network service providers*, July 2010, p. 19.

The AER does not consider Officer and Bishop's use of implied volatility and their 'glide path' approach is a reliable method of estimating a forward looking 10 year MRP. The AER's concerns are outlined in appendix A.

5.5.2.5 Survey evidence

Surveys of market practitioners and academics reflect the forward looking MRP applied in practice. Survey results are subjective, because market practitioners may look at a range of different time horizons and they are likely to have differing views on market risk. However, survey based estimates of the MRP are both forward looking and reflect actual market practice. Furthermore, the fact that different surveys and methodological designs tend to invoke similar responses indicates that there is no reason to suspect bias in this type of evidence. Therefore, the AER is of the view that survey based estimates should be considered when estimating the MRP for the purposes of this access arrangement review.

In the WACC review final decision, the AER noted that survey based estimates of the MRP prior to the onset of the GFC supported a forward looking estimate of 6 per cent:

- Truong, Partington and Peat (2008) found that the MRP adopted by Australian firms in capital budgeting ranged from 3–8 per cent, with an average of 5.94 per cent. The most commonly adopted MRP was 6 per cent.

- Capital Research (2006) found that the average MRP adopted across a number of broker dailies was 5.09 per cent.

- KPMG (2005) found that the MRP adopted in independent expert valuation reports ranged from 6–8 per cent. KPMG's results showed that 76 per cent of survey respondents adopted an MRP of 6 per cent. [189]

During the WACC review the AER had regard to these surveys in concluding the best estimate of the MRP prior to the onset of the GFC was 6 per cent. However, the surveys were conducted before the onset of the GFC, which was expected to affect market practitioners' views of the future.

The most recent survey based estimates of the MRP from Fernandez and Del Campo in May 2009 and May 2010 suggest that market views of the MRP did not significantly differ from those expressed prior to the onset of the GFC:

- Fernandez and Del Campo (2009) found that the MRP used by Australian academics in 2008 ranged from 2–7.5 per cent with an average of 5.9 per cent.[190]

- Fernandez and Del Campo (2010) found that the MRP used by Australian analysts in 2010 ranged from 4.1–6 per cent with an average of 5.4 per cent.[191]

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189 AER, *WACC review final decision*, 1 May 2010, pp. 221–225.

190 Fernandez and Del Campo, *Market Risk Premium used by Professors in 2008: A Survey with 1400 Answers, IESE Business School Working Paper*, WP-796, May 2009, p. 7.

191 Fernandez and Del Campo, *Market Risk Premium Used in 2010 by Analysts and Companies: A Survey with 2400 Answers, IESE Business School*, May 21 2010, p. 4.

Independent valuation reports that were completed following the GFC have also adopted an MRP of 6 per cent.[192] For example, Grant Samuel noted in 2009 it has consistently adopted an MRP of 6 per cent and that in view of general uncertainty, this continues to be a reasonable estimate.[193] The AER considers this provides some indication that expectations of the forward looking 10 year MRP have not been affected by the GFC, and that a structural break of the type considered at the time of the WACC review has not occurred.[194] Moreover, this evidence supports the view that 6 per cent is the best estimate of the forward looking MRP in the current circumstances.

5.5.2.6 Economic outlook and current market conditions

Synergies submitted that global market conditions remain uncertain following the GFC and this is reflected in statements by the Reserve Bank of Australia (RBA), the World Bank, the Economist and the Organisation for Economic Co-operation and Development (OECD).[195] The relevant market for the purposes of determining the MRP is the Australian market. All of the views quoted by Synergies relate to the global economy. Global market conditions may affect the Australian market. However, recent comments from the International Monetary Fund (IMF), the OECD and the RBA indicate that the market outlook for Australia in particular has improved considerably since the GFC.

In a May 2010 paper titled the *Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis*, the IMF noted:

> For Australia, investment barely fell in 2009, and average investment growth is expected to be slightly stronger over the medium term … growth in the capital stock is expected to be almost twice the level of New Zealand.[196]
>
> The global downturn had a fairly small impact on the Australian economy, as real investment barely contracted in 2009 and the unemployment rate went up by less than 2 percentage points. Not surprisingly, Australia's potential growth is estimated to have declined by just ⅓ percent to 3.1 percent in 2009. In comparison, New Zealand's decline in potential growth was only slightly smaller than that of Canada and the U.S. in 2009.[197]

In its November 2010 economic outlook summary for Australia, the OECD forecast robust economic growth in Australia. The OECD stated:

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192 Grant Samuel and Associates, *Financial services guide and independent expert's report in relation to the recapitalisation and restructure of Babcock and Brown Infrastructure*, 9 October 2009, Appendix 1, p. 7; Deloitte, *Arrow Energy Limited Independent expert's report and financial services guide*, 2 June 2010, p. 82. Grant Samuel and Associates, *Financial services guide and independent expert's report in relation to the ConocoPhillips proposa*l, 15 September 2008, appendix 4, p. 6. Grant Samuel and Associates, *Financial services guide and independent expert's report in relation to the proposed acquisition of the Alinta assets from Singapore Power International Pty Limited*, 5 November 2007, Appendix 1, p. 6.

193 Grant Samuel and Associates, *Financial services guide and independent expert's report in relation to the recapitalisation and restructure of Babcock and Brown Infrastructure*, 9 October 2009, Appendix 1, p. 7.

194 AER, Final decision, *Review of weighted average cost of capital parameters*, 1 May 2009, pp. 237–238.

195 Synergies, *Estimating a WACC for the NT gas transmission pipeline*, December 2010, pp. 69–71.

196 Yan Sun, *Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis*, IMF Working Paper, WP/10/27, May 2010, pp. 9–10.

197 Yan Sun, *Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis*, IMF Working Paper, WP/10/27, May 2010, p. 19.

> The Australian economy, fuelled by the mining boom, should grow robustly in 2011 and 2012 at a rate of between 3½ and 4%. Strong growth, driven by terms of trade gains and dynamic investment, will reduce unemployment.[198]

In its November 2010 statement on monetary policy, the RBA forecast robust economic growth in the Australian economy. The RBA stated:

> GDP is expected to expand by 3.5 per cent over 2010 and then by 3.75–4 per cent over both 2011 and 2012. This forecast continues to be driven by the effects of the income boost flowing from the very high level of the terms of trade and the expected substantial increase in business investment, particularly in the resource sector.[199]

More recently, in its February 2011 statement on monetary policy, the RBA continued to forecast robust economic growth. The RBA stated:

> Over the four quarters to December 2011, GDP is expected to increase by 4¼ per cent. This is higher than was expected at the time of the November Statement, but this revision reflects the lower starting point as a result of the flooding in December 2010. Beyond 2011, GDP is forecast to grow by 3¾–4 per cent.[200]

The OECD's financial conditions index gives an indication of likely future GDP growth. The OECD has noted that its financial conditions index for the United States, Japan and the Euro area has stabilised since the onset of the GFC.[201] This indicates a positive global market outlook and is illustrated in figure 5.2.

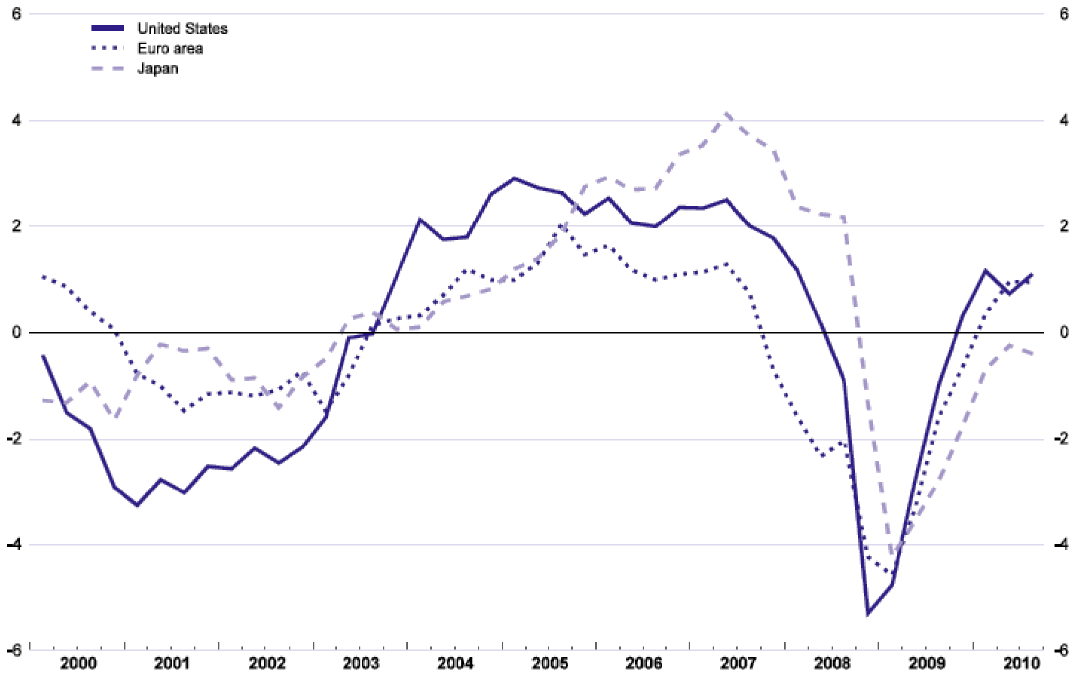
198 OECD, *Australia economic outlook 88—country summary*, November 2010, http://www.oecd.org/document/15/0,3746,en_2649_34573_45268687_1_1_1_1,00.html, viewed 23 December 2010.

199 RBA, *Statement on monetary policy*, November 2010, p. 3.

200 RBA, *Statement on monetary policy*, February 2011, p. 3.

201 OECD, *Economic outlook no. 88: Press conference Paris*, 18 November 2010, p. 17.

Figure 5.2: OECD financial conditions index



Source: OECD, Economic outlook no. 88: Press conference Paris, 18 November 2010, p. 17.

The robust economic outlook in Australia, as noted by statements from the IMF, the OECD and the RBA suggest that market conditions appear to have stabilised to the extent that investors are no longer factoring the substantial volatility experienced at the height of the GFC into their expectations of the future. This is supported by survey evidence and independent valuations presented above. Therefore the conditions that underlined the AER's reasons for increasing the MRP to 6.5 per cent during the WACC review appear to no longer be present.

5.5.2.7 Conclusion – market risk premium

The MRP is an unobservable forward looking estimate. The AER considers that the MRP value chosen should be informed by a range of evidence, noting the particular advantages and limitations of each source of information.

In the WACC review, the AER considered the best estimate of the forward looking 10 year MRP was 6 per cent based on historical estimates, survey based estimates and past regulatory practice. However, given prevailing uncertainty about the potential impact on investor expectations of the GFC, the AER exercised its judgment to increase the MRP to 6.5 per cent. The latest evidence now indicates the AER's caution in raising the MRP to 6.5 per cent is no longer warranted. The significant uncertainty that characterised markets at the time the AER made the WACC review final decision has so substantially diminished that it is not reflected in prevailing conditions in the market for funds, nor is it expected to form part of forward looking expectations of returns over the next 10 years.

The latest long term historical estimates of excess returns using arithmetic means produce a range of 6.1–6.6 per cent (assuming an imputation credit utilisation rate of

0.65). However, consistent with previous regulatory practice, the AER has not mechanistically relied on these figures. This is because such measures may overstate the forward looking MRP, are highly sensitive to additional years of observations and are also inherently imprecise. The AER does not consider the latest historical excess return estimates are inconsistent with the long term MRP value of 6 per cent previously estimated by the AER and other regulators.

Survey based estimates of the MRP indicate that the forward looking MRP expected to prevail in the future has not changed as a result of the GFC. Survey based estimates of the MRP both before and following the GFC suggests a value of 6 per cent is consistent with the views of market practitioners, academics and independent valuation reports.

Comments from the OECD, the IMF and the RBA indicate a robust outlook for the Australian economy, which further suggests that investor expectations of market returns would now reflect those seen prior to the onset of the GFC.

Overall the available evidence on the MRP is imprecise and as a result the MRP is subject to a wide margin of variation. The AER has used its judgement to interpret the evidence currently before it and considers the available evidence both prior to, and following, the GFC supports 6 per cent as the best estimate of the forward looking 10 year MRP in the current market circumstances. The AER considers that an MRP of 6.5 per cent proposed by NT Gas is not the best estimate possible in the circumstances (rule 74(2) of the NGR) and is not consistent with the requirement that the rate of return is to be commensurate with prevailing conditions in the market for funds (rule 87(1) of the NGR).

The AER considers the MRP of 6 per cent meets the requirements under the NGR. It is also consistent with the revenue and pricing principle set out in section 24(2)(a) of the NGL, which states that the service provider should be provided with a reasonable opportunity to recover at least the efficient costs. The AER considers the MRP of 6 per cent best meets 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 price, quality, safety, reliability and security of supply of natural gas.

5.5.3 Debt risk premium

The DRP is the margin above the nominal risk-free rate that a debt holder would require in order for it to invest in a benchmark efficient firm. When combined with the nominal risk-free rate, the DRP represents the return on debt and is an input for calculating the WACC.

The cost of debt varies depending on the firms' default risk. The risk of default is generally taken into account by a firm's credit rating and reflects both the operational and financial risks of the debt issuance. Typically, a lower credit rating is associated with a higher yield to maturity demanded by investors.[202] The cost of debt will also vary depending on the term of the debt. Higher yields are often associated with longer

202 That is, investors would typically require a higher yield for a BBB bond, as distinct from the yield required on an otherwise equivalent AAA rated bond.

terms of debt, reflecting the increased risk of a bond provider defaulting at some point over the life of a longer term bond.

Prior to the onset of the GFC, when market conditions were relatively robust and liquidity was high, the AER placed heavy reliance on the fair value estimates produced by Bloomberg and CBASpectrum. However, deciding on the appropriateness of these estimates with respect to the ten year BBB+ benchmark has become increasingly difficult, and is the subject of several applications for review to the Australian Competition Tribunal.

The decision by CBASpectrum to cease publishing its estimates makes this task even more difficult, particularly as it reflects on the reliability of Bloomberg's estimates given they are based on the same type of market information. To this end, the AER notes that Bloomberg ceased publishing its ten and eight year BBB rated estimates in late 2007 and August 2009 respectively, and then again in June 2010 stopped publishing ten year AAA rated estimates. For the BBB rated fair values Bloomberg currently publishes, the AER has commented previously that these tend to reflect yield observations for bonds traded below a seven year maturity. However this assessment was in the absence of any alternative benchmark developed independently of the regulatory process. Furthermore, observed yield data on which this assessment was made did not display any systematic relationship with respect to maturity or credit rating, rather yields were randomly distributed around the Bloomberg curve.[203]

In this context, and as further detailed in appendix B, the AER has not placed sole reliance on Bloomberg. The key considerations in reaching this decision are that:

- There is evidence to suggest that the behaviour of the Bloomberg curve since the onset of the GFC is somewhat counterintuitive, including the extrapolated ten year DRP derived from Bloomberg currently nearing all time highs. The spread between Bloomberg's seven and ten year, AAA rated fair value estimates—which is used by the AER to extrapolate Bloomberg's seven year, BBB rated fair value estimates—also remains at near historical highs. This implies that prevailing conditions in debt markets are more risky now than during the GFC. This is counterintuitive, and other evidence (such as that assessed throughout the remainder of this section) indicates financial market conditions have substantially improved since this time.

- The characteristics of the APT bond closely match those of the benchmark corporate bond set by the AER, namely its BBB rating and approximate ten year maturity. As this bond has a lower credit rating than the BBB+ benchmark, its use would be expected to result in a DRP that overstates the benchmark cost of debt.

- The APA Group is an owner of various regulated and unregulated energy network assets. The nature of the underlying risk and markets in which the APA Group operates resembles those of the benchmark gas pipeline service provider. To the extent that credit ratings are an imperfect indicator of default risk, the APT bond is suitable for deriving a DRP that reflects the risks involved in providing reference services.

203 AER, *Final decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, October 2010, p. 502.

- A recently issued A- rated, ten year bond by SP AusNet displays yields that are considerably below the APT bond. Similarly, the A- rated, ten year bond issued by Stockland has a yield comparable to the APT bond. Accordingly, both yields are significantly below the extrapolated ten year, BBB rated Bloomberg estimates.[204] This gives further support for relying on the APT bond instead of only the Bloomberg estimates.

- A recently issued BBB rated, eight year bond by Brisbane Airport displays yields that are approximately 25 basis points below the APT bond and over 190 basis points below Bloomberg's fair value estimates. This also provides support for relying on the APT bond instead of only the Bloomberg estimates.

- The BBB rated, Sydney Airport floating rate bonds maturing in 2021 and 2022 respectively, are currently trading at yields between 86 and 99 basis points below Bloomberg's ten year, BBB rated fair value estimates.

- The ten year, BBB+ rated Dalrymple Bay Coal Terminal (DBCT) bond—which has yields that are higher than Bloomberg's BBB fair values—has been discounted by the AER for the purposes of comparison given that ongoing market perceptions of the bonds credit rating may have shifted. Further concerns with respect to its owner and credit wrapper also limit the reliability of the DBCT bond for the purpose of assessing the benchmark cost of debt.

- Other regulators—specifically the ERA and IPART—have recently published discussion papers with indicative debt margins over 200 basis points below NT Gas's proposal.[205]

While the evidence available to assess the benchmark cost of debt is limited, the AER considers that placing sole reliance on Bloomberg estimates would not result in a rate of return that is commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services. This view is supported by the ACG, who submitted that the proposed debt margin is "manifestly excessive".[206]

In these circumstances the AER considers it prudent to adopt an approach which does not place complete reliance on either Bloomberg or the APT bond. Accordingly the AER has set the DRP as an average of the spreads of the extrapolated Bloomberg ten year, BBB fair value estimate and of the APT bond maturing in 2020.[207] Based on the indicative averaging period for this draft decision, these two information sources produce margins over the risk free rate of 4.60 per cent and 2.98 per cent, which the

204 Bloomberg does not publish separate fair value estimates for BBB-, BBB and BBB+ rated debt. Instead, all BBB bonds are included in a single sample. References within this chapter to Bloomberg's BBB fair value estimates encompass all bonds with a credit rating of either BBB-, BBB or BBB+.

205 IPART, Developing the approach to estimating the debt margin, Other industries – draft decision, February 2011; Economic Regulation Authority, *Measuring the debt risk premium: a bond-yield approach, Discussion paper*, December 2010.

206 The Allen Consulting Group, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation in support of its submission to the AER's access review*, February 2011, p. 6.

207 The margin on the APT bond (2.98 per cent) reflects a simple average of both Bloomberg and UBS yields over the 20 day averaging period ending 1 April 2011.

AER has averaged to produce a DRP of 3.79 per cent. The AER considers this is the best DRP estimate possible in the circumstances of NT Gas.[208]

Additionally, as part of its assessment of the recent QLD gas distribution access arrangement proposal from APT Allgas, the AER requested and received actual costs of debt data from the APA Group.[209] This information supported that the AER's estimate of the DRP for APT Allgas provided a reasonable opportunity for APT Allgas to recover at least its efficient costs. Given NT Gas is owned by the APA Group, as per APT Allgas, the AER considers that its DRP allowance for NT Gas, based on the same actual costs information, also provides a reasonable opportunity for NT Gas to recover at least its efficient costs.[210]

Placing equal reliance on Bloomberg and the APT bond, though consistent with the recent QLD and SA gas draft access arrangement decisions, contrasts from the most recent final decision of the AER. This decision (for the Victorian electricity distribution businesses) determined the DRP based on a 75 per cent weighting to estimates from Bloomberg and a 25 per cent weighting to estimates from the APT bond. The increased reliance on the APT bond in this decision is primarily the result of Bloomberg's more recent estimates being unusually high, the recent availability of yields for two Sydney Airport bonds, and the recent issuance of the SP AusNet, Brisbane Airport and Stockland bonds. The AER also notes that the Victorian final decision is currently the subject of a merits review before the Australian Competition Tribunal. The AER will consider the outcome of the merits review and the implications, if any, for DRP as appropriate in its final decision.

5.5.4 Equity beta

The equity beta measures the standardised correlation between the returns on an individual risky asset or business with that of the overall market. It represents the 'riskiness' of the business' returns compared with that of the market. A beta estimate of greater (less) than one implies that the business is exposed to more (less) non diversifiable risk than the overall market. Risk results from the possibility that returns will differ from expected returns—the greater the uncertainty around the returns of a business, the greater its level of risk.

Consistent with the WACC review, the AER considers an equity beta estimate of 0.8 is appropriate and will result in a rate of return commensurate with the risk involved in providing reference services. The AER considers that regulated utilities face lower systematic risk than the general market, which is primarily driven by the stable cash flows of regulated utilities. The lower equity beta value of 0.8 is partly due to the regulatory regime that provides protection to regulated businesses that is not available to businesses in the competitive environment, particularly as:

- the tariff variation mechanism allows for the annual adjustment for inflation, lowering exposure to inflation risk

208 NGR, r. 74(2)(b).

209 The debt information provided reflected debt held by the APA Group that was not specific to any of its constituent businesses. Hence, while such debt is not specifically allocated to NT Gas, it is still reflective of its cost of debt in so far as it is part of the APA Group.

210 NGL, s. 24(2).

- the roll forward of the capital asset base occurs in a manner that lowers exposure to cost overruns for capital expenditure

- the cost pass through mechanism allows for certain costs to be passed on to consumers during the access arrangement period, lowering exposure to costs not forecast at the commencement of the access arrangement period

- the access arrangement provides for acceleration of the review submission date on occurrence of a trigger event

- a service provider may submit an access arrangement variation proposal for the AER's approval.

Consistent with the ACCC's decision in 2002, [211] the AER does not consider that asset stranding risk on the AGP is a systematic risk driver for the purposes of its beta analysis. Further, the AER considers the risk of asset stranding that was accepted by the ACCC in its earlier access arrangement review for the AGP, and compensated for through an accelerated depreciation allowance, has largely been eliminated.[212] The AER's considerations of stranding risk on the pipeline are detailed in appendix A, but can be summarised as follows:

- NT Gas has proposed a single zone reference tariff, under which all sections of the pipeline will be equally price competitive. [213]

- the majority of pipeline capacity is expected to be contracted to a single user during and beyond the access arrangement period[214]

- new gas fields are supplying natural gas to the pipeline, alleviating concerns of depleted supply reserves.

In this context, the AER rejects NT Gas's proposed equity beta estimate of 1.0 as it would result in a cost of capital which is excessive with respect to the risks involved in providing reference services. Appendix A contains further detail on particular issues raised by NT Gas in relation to beta.

Taking account of the estimated equity betas provided in the Competition Economist Group report for Envestra and the equity beta estimates from the WACC review, the AER considers that a beta estimate from empirical evidence in the range of 0.4 and 0.7 is still appropriate for this draft decision.[215] Table 5.5 reproduces the most up to date beta estimates from the Competition Economist Group report. As is evident in

211 ACCC, *Final decision–NT Gas*, December 2002, pp. 19–20.

212 ACCC, *Final decision–NT Gas*, December 2002, p. 68.

213 NT Gas, *Access arrangement information*, December 2010, p. 29.

214 NT Gas, *Access arrangement submission*, December 2010, p. 10.

215 Competition Economist Group, *Estimating the cost of capital under the NGR A report for Envestra*, September 2010, p. 49–50. This was received as a part of Envestra's recent access arrangement proposal for its Queensland and South Australian businesses. It can be found on the AER website: http://www.aer.gov.au/

table 5.5, the most recent beta estimate from Australian comparable firms (with the exception of Hasting[216]) is within the bound of 0.1 to 0.6.

Table 5.5: Comparison of Competition Economist Group beta analysis with the AER's WACC review

Company	Competition Economist Group equity beta at 60% gearing	WACC review
Envestra	0.51	0.10–0.42
Hastings	1.64	0.49–1.01
Australian Pipeline	0.54	0.60–0.92
DUET	0.34	0.19–0.41
Spark Infrastructure	0.53	0.79–1.11
SP AusNet	0.14	na

Source: AER analysis; Competition Economist Group, *Estimating the cost of capital under the NGR A report for Envestra,* September 2010, p. 49 and Olan T. Henry, *Estimating beta,* 23 April 2009, pp. 10–18.

Based on this information, the AER considers that an equity beta of 0.8 is sufficient to ensure that the service provider has the opportunity to recover at least its efficient costs incurred in providing reference services and meeting regulatory requirements.[217] The AER considers that a reduction in NT Gas's beta from 1.0 to within a range of 0.4 to 0.7 as suggested by market data is significant. However, the AER has given consideration to other factors, such as the need to achieve an outcome that is consistent with the national gas objective (in particular, the need for efficient investment in natural gas services for the long term interests of consumers of natural gas). The AER has also taken into account the revenue and pricing principles, the importance of regulatory stability and is also mindful it has recently considered a beta value of 0.8 to be appropriate, if not overstated, for other gas businesses.

On the basis of the information presented here, the AER concludes that a beta value of 0.8 is appropriate. The AER considers that a value of 1.0 does not provide the best estimate of the equity beta given prevailing market conditions,[218] and requires NT Gas to amend its access arrangement information as outlined in amendment 5.1.

5.5.5 Inflation forecast

The expected inflation rate is not an explicit parameter within the WACC calculation. However, it is used in the revenue model to forecast nominal allowed revenues and to index the capital base. It is an implicit component of the nominal risk-free rate, with

216 Given the take over bid, refinancing pressure and sharp falls in the share price of HDF in 2009, the AER considers caution should be used when interpreting the Hasting beta estimate.

217 NGL, s. 24(2).

218 NGR, r. 74 (2)(b) and r. 87 (1).

implications for the return on both equity and debt. The inflation forecast must be consistent with the ten year investment horizon of the risk free rate.

NT Gas proposed to use the mid point of the RBA's inflation target band (that is, 2.5 per cent) as the 10 year inflation estimate. The AER agrees that the most appropriate estimate of inflation, beyond the two year short-term forecast provided by RBA in its statement on monetary policy, should be the mid point of the RBA's inflation target band. This is because the monetary policy is set with the aim to achieve the target inflation of between 2 to 3 per cent over the medium-term. However, the inflation target is defined as a medium-term average rather than as a rate (or band of rates) that must be held at all times. This formulation allows for the lags in the effects of monetary policy on the economy.[219] As a result, it is possible for the short-term inflation to deviate from the target band set by the RBA. For this reason, the AER considers that the short-term inflation forecast provided by RBA in its statement on monetary policy should also be included as part of the calculation to obtain the best estimate of inflation over 10 years as required under r. 74 of the NGR.

The AER considers that an inflation estimate of 2.5 per cent should be adopted for the purpose of this draft decision. This is calculated by taking the geometric average of RBA's short-term inflation forecasts extending out for two years, and the mid-point of the RBA's target inflation band for the remaining eight years as set out in table 5.6.

Table 5.6: AER inflation rate forecast (%)

	Jun–12	Jun–13	Jun–14	Jun–15	Jun–16	Jun–17	Jun–18	Jun–19	Jun–20	Jun–21	Geometric average
AER inflation forecast	2.75	3.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.57

Source: RBA, *Statement on monetary policy*, February 2011, p. 60.

The AER considers that the estimate of expected inflation should be updated to incorporate the latest available data closer to the time of the final decision. Inflation forecasts can change in line with market sensitive data and regulatory practice in Australia has been to update these forecast values at the time of making a decision. The AER will update its estimate of inflation based on the latest RBA forecasts as close as is practical to the date of the final decision.

5.5.6 Averaging period and risk free rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth Government Securities (CGS) is often used as a proxy for the risk-free rate because

219 See RBA, About monetary policy, access from http://www.rba.gov.au/monetary- policy/inflation-target.html

the risk of government default on interest and debt repayments is considered to be low.[220]

In the CAPM framework, all information used for deriving the rate of return should be as current as possible in order to achieve an unbiased forward looking rate and a rate of return that is commensurate with prevailing conditions in the market for funds. While it may be theoretically correct to use the on the day rate as it represents the latest available information, this can expose the service provider and customers to daily volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.[221]

NT Gas proposed an averaging period of 20 business days ending 1 April 2011.[222] The AER accepts the nominated averaging period as it satisfies the requirement of r. 87 of the NGR, and has been proposed in advance of the commencement of the period. For this draft decision, the AER has used the nominated averaging period to calculate a risk free rate of 5.53 per cent. This averaging period will also be used for the final decision.

5.5.7 Gearing ratio

The gearing ratio is defined as the ratio of the value of debt to total capital (that is, debt and equity), and is used to weight the costs of debt and equity when formulating the WACC.

The AER accepts NT Gas's proposed gearing ratio of 60 per cent. This value is consistent with the benchmark ratio determined by the AER during the WACC review, which was based on a variety of information sources and analysis of a wide variety of firms across the gas and electricity sectors.

5.6 Conclusion

The AER does not propose to approve the rate of return on capital proposed by NT Gas as it does not comply with r. 87 of the NGR and requires NT Gas to make the amendments set out below.

5.7 Required amendments

Before its access arrangement proposal can be accepted, NT Gas is required to make the following amendment:

Amendment 5.1: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of the rate of return calculated in accordance with the following table.

220 AER, *Final decision: Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters*, 1 May 2009, pp. 128–174 (AER, *Final decision: WACC Review*, 1 May 2009).

221 AER, *Final decision: WACC review*, 1 May 2009, pp. 128–174.

222 NT Gas, *Access arrangement submission*, December 2010, attachment G (confidential), NT Gas, E-mail to AER, *RE: Averaging period*, 28 March 2011

Table 5.7: WACC parameters for the access arrangement period (units as stated)

Parameter	
Nominal risk–free rate (%)	5.53
Inflation (%)	2.57
Real risk–free rate (%)	2.89
Equity beta	0.8
Market risk premium (%)	6.0
Debt risk premium (%)	3.79
Gearing (%)	60
Cost of debt (%)	9.32
Cost of equity (%)	10.33
Nominal vanilla WACC (%)	**9.72**

6 Tax

The AER has accepted the post-tax approach proposed by NT Gas for the access arrangement as it is consistent with revenue and pricing principles under s. 24(2) of the NGL. This allows the service provider reasonable opportunity to recover the efficient costs incurred in providing reference services. The AER has also accepted the way that taxation is to be calculated (including the use of a 30 per cent corporate tax rate), and the tax asset lives proposed by NT Gas. These matters were investigated by the AER and found to have been appropriately calculated by NT Gas.

The AER does not consider the roll forward of the tax asset base proposed by NT Gas as it does not reflect historic and current tax law. Therefore, the AER does not accept the opening tax asset base and tax remaining lives as proposed by NT Gas to estimate the cost of corporate income tax.

The AER does not accept NT Gas's proposal that it does not have a tax loss carried forward because it is not a tax paying entity. There were tax losses offset against tax obligations during the earlier access arrangement period. The AER considers that there remains a residual amount of tax losses carried forward as at 1 July 2011, which the AER has estimated to be $7.8 million.

NT Gas's estimate of the use of imputation credits by investors (gamma) of 0.2 has been rejected by the AER. Based on the currently available evidence, the AER considers the best estimate for the value of gamma to be 0.45.

The AER has calculated a total $4.0 million in forecast tax for the access arrangement period. This forecast reflects the revised revenue and cost figures presented in the various chapters of the draft decision.

6.1 Introduction

This chapter provides the AER's assessment of NT Gas's proposed method to establish an allowance for taxation for the access arrangement period.

6.2 Regulatory requirements

Rule 72(1)(h) of the NGR provides that the access arrangement information for an access arrangement proposal must include the proposed method for dealing with taxation, and a demonstration of how the allowance for taxation is calculated.

Rule 76(c) of the NGR provides for the estimated cost of corporate taxation as a building block for total revenue insofar as this is applicable.

6.3 Access arrangement proposal

NT Gas proposed a post-tax method to estimate total revenue over the access arrangement period.[223] In the earlier access arrangement review, the ACCC approved a post-tax method.[224]

223 NT Gas, *Access arrangement information*, December 2010, p. 26.

224 ACCC, *Final decision*, December 2002, p. 78.

NT Gas proposed to adopt the AER's Post-Tax Revenue Model (PTRM) to calculate its tax allowance.[225] Further, NT Gas has proposed a corporate tax rate of 30 per cent, which it has considered consistent with regulatory precedent.[226]

NT Gas submitted that the reasonable range for gamma is between zero and 0.57, and proposed a point estimate of 0.2.[227]

NT Gas adopted the opening tax asset base (TAB) as at 1 July 2001 which was estimated by the ACCC for the earlier access arrangement. NT Gas has proposed to roll forward the TAB taking into account actual capital expenditure (capex), disposals and tax depreciation.[228] On this basis, NT Gas proposed a closing TAB as at 30 June 2011 of $24 million (nominal) as shown in table 6.1.

Table 6.1: NT Gas proposed tax asset base as at 30 June 2011 (nominal $'000)

	2001–02	**2002–03**	**2003–04**	**2004–05**	**2005–06**
Opening TAB	22263	18004	14751	14542	12186
Additions	215	377	2916	383	496
Disposals		2		4	2
Tax depreciation	4473	3629	3124	2735	2286
Closing TAB	**18004**	**14751**	**14542**	**12186**	**10394**
	2006–07	**2007–08**	**2008–09**	**2009–10**	**2010–11**
Opening TAB	10394	8791	7841	6959	6353
Additions	318	702	583	670	19723
Disposals	2		11	8	
Tax deprecation	1918	1652	1454	1267	2085
Closing TAB	**8791**	**7841**	**6959**	**6353**	**23991**

Source: NT Gas, *Access arrangement information*, December 2010, p.26.

Table 6.2 shows NT Gas's proposed opening TAB as at 1 July 2011. The standard and remaining tax asset lives proposed by NT Gas are also presented in this table.

225 NT Gas, *Access arrangement submission*, December 2010, attachment E-3, (confidential).

226 NT Gas, *Access arrangement submission*, December 2010, attachment E-3, (confidential).

227 NT Gas, *Access arrangement submission*, December 2010, p. 113.

228 NT Gas, A*ccess arrangement submission*, December 2010, attachment E-3, (confidential).

Table 6.2: NT Gas's proposed tax asset base as at 1 July 2011

Asset Category	Tax value ($m, nominal)	Tax Standard Lives (yrs)	Tax Remaining Lives (yrs)
Pipeline	10.8	20	7.7
Compression	0.3	20	0.0
Meter station	10.0	20	8.8
SCADA and communications	1.6	15	1.7
O&M facilities	1.2	10	6.7
Buildings	0.0	40	36.0

Source: NT Gas, *Access arrangement submission*, December 2010, p. 188, attachment B (confidential).

NT Gas did not provide an analysis of whether it had any tax loss carried forward.

NT Gas proposed an estimate of the use of imputation credits (gamma) of 0.2.[229] NT Gas derived its estimate of gamma through separately estimating its subcomponents, specifically the payout ratio (the proportion of imputation credits generated that are distributed to shareholders) and the rate of imputation credit utilisation (or theta). NT Gas submitted that evidence does not support a payout ratio value above 70 per cent, and that an appropriate range for theta is between zero and 0.57.[230] When these values of the payout ratio and theta are multiplied this produces a range of gamma of between zero and 0.4, from within which NT Gas submits its proposed value of gamma is conservative.[231] NT Gas noted that a number of merits review applications have been submitted on this matter and the outcome of these appeals will be the key driver of future decisions in relation to gamma.[232]

NT Gas submitted a Synergies report to support its gamma estimate. Synergies noted that it has already presented analysis on gamma to the AER as part of the review of the APT Allgas access arrangement submitted in September 2010. Synergies stated that its assessment has not changed and provided the following key arguments:

- given the absence of evidence to the contrary and the asymmetric consequences of regulatory error, any retained credits should be given zero value when estimating the payout ratio

- the AER should not place full weight on the Beggs and Skeels (2006) dividend drop off study and should instead consider the evidence from a range of studies, including the 2010 SFG report, particularly in light of recent comments made by the Australian Competition Tribunal

229 NT Gas, *Access arrangement submission*, December 2010, p. 113.

230 NT Gas, *Access arrangement submission*, December 2010, pp. 112-3.

231 NT Gas, *Access arrangement submission*, December 2010, p. 113.

232 NT Gas, *Access arrangement submission*, December 2010, p. 112.

- the AER's reliance on post-2000 data only is based on the evidence provided in the Beggs and Skeels study which is not sufficiently reliable to enable one to conclude there has been a structural break from this time

- the AER should not rely on the Handley and Maheswaran (2008) tax statistics analysis as it does not reflect a market value of theta.[233]

Table 6.3 sets out NT Gas's proposed tax allowance for the access arrangement period. These forecasts reflect the revenues/expenses that NT Gas has proposed to earn/incur over the access arrangement period.

Table 6.3 NT Gas's proposed tax allowance (Nominal $ '000)

	2011–12	2012–13	2013–14	2014–15	2015–16
Tax	1874	1755	1996	2023	874

Source: NT Gas, *Access arrangement information*, December 2010, p. 26.

6.4 Submissions

The Northern Territory Major Energy Users (NTMEU) submitted that there was a prima facie assumption that the notional Australian regulated energy network provider could be owned by Australians who receive benefits from the imputation tax arrangement, hence expected a gamma of value of 1; and that the AER's value of 0.65 (adopted in the WACC review) was extremely conservative.[234]

The Allen Consulting Group (ACG) was engaged by the Power and Water Corporation (PWC) to make a submission on NT Gas's proposed WACC parameters. As part of this review, ACG identified that Australian regulators historically set gamma values at 0.5 or above, and that the available evidence supported application of a gamma value 'closer to one than zero'.[235]

Santos Limited and Magellan Petroleum Australia Limited (Santos and Magellan) jointly submitted that NT Gas had understated the value of gamma, and recommended the AER apply a value of 0.5 to be consistent with regulatory precedent.[236]

6.5 AER's consideration

The AER accepts NT Gas's proposed post-tax approach for the access arrangement period.[237] This approach has been adopted in all previous AER gas and electricity decisions. The alternative pre-tax approach has not been used by the AER to date. The post-tax approach is considered by the AER to be a superior to the pre-tax approach in that it facilitates a more accurate tax allowance in the setting of regulatory revenues.[238] The post-tax approach enables adjustment to changing tax legislation and

233 Synergies, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 76-85.

234 NTMEU, *Submission to the AER*, February 2011 p. 56

235 ACG, *Amadeus Gas Pipeline— Estimation of WACC*, February 2011, p. 8.

236 Santos and Magellan, *Submission to the AER*, February 2011, p. 11.

237 NGR, r. 72(1)(h).

238 AER, *Electricity Distribution Network Service Providers: transition of energy businesses from pre-tax to post-tax regulation*, June 2007, p.1.

provides a realistic assessment of cost faced by an actual firm based on regulated revenues. This approach is consistent with the provision of a reasonable and best estimate under rule 74(2) of the NGR.

The AER is aware that NT Gas is the trustee of the Amadeus Gas Trust and may not be a tax paying entity under tax law. However, consistent with NT Gas's proposal to recover an estimated cost of corporate income tax, the AER considers that NT Gas be allowed to recover such a cost based on a best estimate.[239] This approach is also consistent with the earlier access arrangement decision of the ACCC which applied a post-tax methodology to setting revenues.[240]

The AER reviewed the proposed taxation calculation and the components that form part of that calculation, including:

- the opening tax asset base, used to determine tax depreciation
- the tax asset lives, used to determine the rate of tax depreciation
- whether there is any tax loss carried forward from the earlier access arrangement period that needs to be offset against future tax claims
- the use of imputation credits (gamma).

These issues are considered in turn below. Besides these considerations, any other component that affects revenues/costs will affect the forecast tax allowance. Accordingly, a change to any of the proposed revenue/cost components in the draft decision will require the forecast tax allowance to be amended.

6.5.1 Opening tax asset base

The AER accepts NT Gas's opening TAB as at 1 July 2001. In its 2002 final decision, the ACCC considered that the adoption of a post-tax regulatory framework necessitated the carry over historic financial accounts that impact on future post-tax returns.[241] The opening TAB as at 1 July 2001 was estimated by the ACCC based on the residual asset value transferred to the post-tax framework. The AER accepts the proposed opening TAB as at 1 July 2001 as being consistent with this residual asset value.

In rolling forward the opening TAB to 1 July 2011, NT Gas has applied a depreciation rate of 20 per cent (on a diminishing value basis) to the assets that comprise its opening TAB as at 1 July 2001. The result of NT Gas's approach is that the opening TAB as at 1 July 2001 is now nearly fully depreciated. The approach used and the depreciation rate applied are consistent with the usual tax approach. Once an asset begins to be depreciated at a given life for tax purposes, it generally continues to be depreciated at that life until fully depreciated under the tax law. This is the preferred approach as discussed in the AER issue paper on transitioning from pre-tax to post-

239 NGL, s.24(2)(a) and (b).

240 ACCC, *Draft Decision – Amadeus Basin to Darwin Gas pipeline access arrangement,* 2 May 2001, p. 63.

241 ACCC, *Draft Decision – Amadeus Basin to Darwin Gas pipeline access arrangement*, 2 May 2001, p. 63.

taxation frameworks.[242] The AER is satisfied with this approach and as a consequence accepts the depreciation rates used by NT Gas as being consistent with various tax rulings over the earlier access arrangement period.[243]

However, the AER does not consider NT Gas's application of the same tax depreciation rate to new assets acquired over the earlier access arrangement period as being appropriate. This is because there have been changes made to the tax law during this period that should be reflected in the depreciation rates applied to capex, as follows:

- in 2001, the Tax Commissioner undertook a review of effective lives which resulted in the determination of new effective lives for gas distribution and transmission assets[244]
- a gas industry addendum to TR 2000/18 came into effect on 1 July 2002, which provided new effective life calculation for gas distribution and transmission assets[245]
- the introduction of a statutory cap of 20 years applied to assets where the Commissioner's determination provided for an effective life greater than 20 years.[246]

Table 6.3 provides a summary of the depreciation rates (based on the diminishing value method) that the AER considers consistent with the tax law and the Tax Commissioners determinations at the time the assets were commissioned. The AER considers that these rates should be applied to the capex incurred over the earlier access arrangement period.

242 AER, *Electricity Distribution Network Service Providers: Transition of energy businesses from pre-tax to post-tax regulation*, June 2007, p. 12.

243 Ernst & Young, *Application of tax depreciation rates to regulated entities for the period 26 February 1992 to 1 November 2006*, January 2007, p. 6.

244 Ernst & Young, *Application of tax depreciation rates to regulated entities for the period 26 February 1992 to 1 November 2006*, January 2007, p. 6.

245 ATO, *Tax Ruling TR 2000/18*, www.ato.gov,.au, viewed on 14 March 2011.

246 Ernst & Young, *Application of tax depreciation rates to regulated entities for the period 26 February 1992 to 1 November 2006*, January 2007, p. 11.

Table 6.3 Asset class tax depreciation rates and tax rulings (%)[ab]

Asset class	1 July 2001	1 July 2002	5 July 2006
Pipeline	20.0	7.5	10.0
Compression	20.0	7.5	10.0
Meter stations	20.0	7.5	10.0
SCADA	20.0	15.0	20.0
O&M facilities	20.0	7.5	10.0
Buildings	10.0	7.5	10.0

Source: ATO, *Taxation ruling – Income tax: depreciation*, www.ato.gov.au, viewed on 14 March 2011, NT Gas, *Access arrangement submission*, December 2010, attachment E–2 (confidential).

a: Date refers to issue date of tax rulings. The tax rulings used refer to IT 2685, TR 2000/18 and TR 2006/05

b: Depreciation rates calculated based on tax rulings using diminishing value method

Given the changes to the depreciation rates discussed above, the opening TAB as at 1 July 2011 rates proposed by NT Gas will require amending. As discussed in chapter 3 of the draft decision, the AER amended the forecast capex for 2010–11. This has also affected the opening TAB as at 1 July 2011, reducing it compared to that proposed by NT Gas. Therefore, the AER does not accept that the opening TAB as at 1 July 2011 proposed by NT Gas represents the best estimate of cost of corporate tax as required by r. 74(2) of the NGR The AER calculates the opening TAB as at 1 July 2011 to be $10.9 million as set out in amendment 6.2.

6.5.2 Asset lives

Tax depreciation reflects the asset lives of the various tax assets. There are two types of tax asset lives:

1. the standard tax asset lives to be applied to new assets
2. the remaining tax asset lives of existing assets.

6.5.2.1 Standard tax asset lives

The AER accepts NT Gas's proposed standard tax asset lives as these are consistent with the requirements of the *Income Tax Assessment Act 1997*.[247] From 1 July 2002, the effective lives of gas transmission assets became subject to a statutory cap of 20 years. A taxpayer choosing to use the Commissioner's determination of effective life must use the shorter of the statutory cap or the Commissioner's determined

247 Australian Taxation Office, *Taxation Ruling TR 2010/2 – 'Income tax: effective life of depreciating assets'*, 2010, p. 10.

effective life.[248] Therefore, the AER accepts the standard tax asset lives proposed by NT Gas.

6.5.2.2 Remaining tax asset lives

The remaining tax asset lives are a function of the tax effective life, the method of depreciation, the tax depreciation rate and the written down value of the asset. The AER considers that the remaining tax asset lives proposed by NT Gas are not consistent with changes the tax law and Tax Commissioner's ruling from 1 July 2001 to 30 June2011.

The remaining lives as contained in the TAB roll forward model proposed by NT Gas indicates a tax effective life of 10 years (the life ascribed in of the earlier access arrangement) for all asset classes. The effect is to depreciate assets at a higher rate which results in a lower opening tax asset base.

In response to email inquiries made by the AER, NT Gas confirmed that the tax effective lives and the method used to depreciate assets is the diminishing value method.[249] The AER accepts the method proposed by NT Gas to depreciate assets for tax purposes. However, it does not consider NT Gas's inputs to the TAB roll forward model are consistent with changes to the tax law and the Tax Commissioners rulings.[250] Therefore, the AER does not accept the value of NT Gas's proposed opening tax asset base and remaining lives used to estimate the cost of corporate tax as it is not consistent with r. 74(2)(b) of the NGR and requires NT Gas to make amendment 6.2. Table 6.3 compares the remaining tax asset lives and closing asset class values derived by NT Gas and the AER.

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248 Australian Taxation Office, Capital allowances: legislative caps on effective life of oil and gas related assets, http://www.ato.gov.au/businesses/content.asp?doc=/content/30407.htm, viewed on 7 February 2011.

249 NT Gas, Email to AER, *Response to AER information request*, 10 March 2011, pp.1-3.

250 Ernst & Young, *Application of tax depreciation rates to regulated entities for the period 26 February 1992 to 1 November 2006*, January 2007, pp. 20-25.

Table 6.3: AER's determination of NT Gas's opening tax asset base and remaining lives

Asset Category	NT Gas Tax value ($m, nominal)	NT Gas Tax Remaining Lives (yrs)	AER Tax value ($m, nominal)[b]	AER Tax Remaining Lives (yrs)
Pipeline	10.8	7.7	4.8	16.0
Compression	0.3	0.0	0.3	0.0
Meter station	10.0	8.8	2.5	17.9
SCADA and communications	1.6	1.7	1.5	8.5
O&M facilities	1.2	6.7	1.8	16.0
Buildings [a]	0.0	36.0	0.0	36.0
Total	24.0	-	10.9	-

Source: NT Gas, *Access arrangement submission*, December 2010, p. 171, attachment E–2, (confidential).

a For tax purposes, buildings did not have any capex during the earlier access arrangement period.

b The AER's calculation of tax depreciation is based on the diminishing value method of depreciation applied over the earlier access arrangement period.

6.5.3 Tax loss carried forward

NT Gas did not provide any demonstration or analysis to support the existence of a tax loss carried forward.[251] The ACCC final decision of 2002 carried over aspects of the historical financial accounts that were likely to impact on future post-tax returns.[252] This resulted in the transfer of the residual asset values and tax depreciation concessions available to offset future taxes, and to ensure that these factors were accounted for in regulated revenues. The ACCC considered that the impact of tax depreciation claimed since 1986 had not been completely exhausted in the reduction of tax payable would still be available to reduce future tax liabilities.[253] The ACCC calculated the tax loss carried forward to be $214.4 million as at 1 July 2002, based on the difference between depreciation for tax purposes and depreciation for accounting purposes since 1986.[254] Due to the size of the tax loss carried forward, NT Gas received no tax allowance during the earlier access arrangement period.

In response to inquiries from the AER, NT Gas stated that because it is a trustee of the Amadeus Gas Trust, it is not a tax paying entity and therefore, does not have a tax loss carried forward.[255] The ACCC identified the benefit that NT Gas would receive in the

251 NT Gas has nonetheless proposed a tax allowance over the access arrangement period.

252 ACCC, *Final decision–NT Gas*, December 2002, p.88.

253 ACCC, *Final decision–NT Gas*, December 2002, p. 88.

254 ACCC, *Draft decision – Access arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline*', May 2001, p. 63.

255 NT Gas, Email to AER, *Re. AER.NTGAS.21-34*, 23 February 2011, attachment.

form of deferred tax liabilities, and applied a tax loss carried forward.[256] The original estimate of the tax loss carried forward was expected to carry over into the access arrangement period.

To maintain consistency access arrangement periods, the AER does not accept the omission of a demonstration by NT Gas to identify whether NT Gas should have a tax loss carried forward. NT Gas proposed that it does not have a tax loss carried forward because it is not a tax paying entity. The AER considers this to be inconsistent with NT Gas's proposed estimation of tax allowance. The AER has conducted its own analysis of the tax loss carried forward as at 1 July 2011. Starting with the tax loss carried forward of $214.4 million as at 1 July 2002 as calculated by the ACCC and using the forecast revenues and expenses approved in the earlier access arrangement period, the AER has calculated a residual tax loss carried forward of $7.8 million as at 30 June 2011. Therefore, the AER does not accept the absence of any analysis of tax loss carried forward is sufficient in determining if the estimated cost of corporate tax is best or reasonable, under r. 74(2)(a) and (b) of the NGR.[257] As a consequence, the AER requires NT Gas to make amendment 6.3. Table 6.4 shows how the AER derived this estimate.

256 ACCC, *Final decision–NT Gas*, December 2002, p. 88.

257 NGR, r.72(h)(1).

Table 6.4 AER derivation of NT Gas's tax loss carried forward as at 30 June 2011.[a]

	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06
Revenue		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Opex		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Interest		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Tax Depreciation		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Pipeline Tariff Margin[b]		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Pre-tax income		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Tax loss carried forward	-214.4	-193.7	-171.4	-147.9	-123.2	-96.8
		2006–07	**2007–08**	**2008–09**	**2009–10**	**2010–11**
Revenue		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Opex		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Interest		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Tax Depreciation		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Pipeline Tariff Margin		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Pre-tax income		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Tax loss carried forward	-96.8	-77.3	-60.4	-43.2	-25.6	-7.8

Source: AER analysis.
a: ACCC, *Final decision model NT Gas.xls*, December 2002 (confidential).
b: ACCC, '*Final Decision – Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline–Annexure D* ', December 2002, pp. 175–176 (confidential).

6.5.4 Use of imputation credits (gamma)

Under the Australian imputation tax system, domestic investors receive a credit for tax paid at the company level (an 'imputation credit') that offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received. Under a post-tax revenue building block framework the value of imputation credits is recognised when determining the corporate income tax building block.

The AER and other Australian regulators define the value of imputation credits in accordance with the Monkhouse definition, where 'gamma' (γ) is defined as a product of the 'imputation credit payout ratio' (F) and the 'utilisation rate' (θ). Gamma has a range of possible values from zero to one.

Under the National Electricity Rules (NER) the AER is periodically required to consult on and publish a Statement of Regulatory Intent (SORI) setting out values, methods and credit rating levels relevant to determining the weighted average cost of capital (WACC) for electricity network service providers. In May 2009 the AER completed its first “WACC review” and published a SORI which prescribes a gamma value of 0.65. This value has been applied in subsequent electricity distribution determinations, where the AER has determined that there has been no persuasive evidence to depart from 0.65.

While the SORI has no direct or formal applicability to gas access arrangements, the AER’s WACC review and SORI provide useful information and analysis to the gas sector on WACC related matters.

On 13 October 2010 the Australian Competition Tribunal (Tribunal) handed down its determination and reasons for decision with respect to the recent appeal by Ergon Energy, Energex and ETSA Utilities of the AER’s South Australia and Queensland electricity distribution determinations in relation to gamma. The Tribunal found errors by the AER in its treatment of the imputation credit payout ratio and the utilisation rate. However, the Tribunal did not make a determination on the correct value of gamma. It directed the AER to undertake further work and sought a report from the AER in relation to various aspects of the calculation of gamma. One element of this work relates to the payout ratio. On 24 December 2010 the Tribunal issued a decision finding that, on the basis of the information before it, a value of 70 per cent was appropriate. The remaining work relates to estimating the utilisation rate (or theta)

The gamma aspect of the application for review by Jemena’s New South Wales gas network has been stayed by the Tribunal. The Tribunal is waiting for the outcome of the review of the South Australia and Queensland electricity distribution determinations in relation to gamma before it makes a decision on the gamma to be applied in the access arrangement for the Jemena New South Wales gas network.

The further work as part of the Tribunal proceedings is ongoing and submissions are scheduled to be heard on 29 April 2011. A decision by the Tribunal is expected before June 2011. This means the expected decision would be available for the AER to take into account for the purposes of determining the final decision for NT Gas’s access arrangement.

Synergies adopted a payout ratio of 71 per cent and a theta estimate in the range 0–0.57. This gave an overall range for gamma estimates of 0–0.4 from which Synergies adopted a mid-point estimate of 0.2.[258] The AER notes that the Tribunal issued a decision on 24 December 2010 finding that on the evidence currently available a payout ratio of approximately 70 per cent is appropriate. No new evidence on the payout ratio has been presented to the AER since the Tribunal’s decision. As a result the AER considers a payout ratio of approximately 70 per cent remains appropriate at this time.

The range of possible values for theta is between 0 and 1. That is, an investor may fully value imputation credits or they may not value imputation credits at all. This is

258 Synergies, *Estimating a WACC for the NT gas transmission pipeline*, December 2010, p. 85.

noted by ACG in its report prepared for the Power and Water Corporation.[259] This is also noted by the NTMEU, which stated that if the regulated network business was Australian owned its shareholders could fully value imputation credits.[260] Furthermore, the AER considers that estimates of the market value of imputation credits derived from dividend drop-off studies are highly uncertain. This was noted by Synergies.[261] Therefore, the AER does not agree with Synergies that the range of possible values for theta is 0–0.57 as submitted by NT Gas.

The AER notes that Synergies has referred to the results of a range of traditional dividend drop-off studies, as well as two non–traditional dividend drop-off studies. However, the only independently published traditional dividend drop-off study that provides an estimate for the post–2000 period is Beggs and Skeels (2006), which estimates theta to be 0.57. The AER notes that from July 2000, imputation credits in excess of tax liabilities became available as cash rebate. This was a major change in the imputation tax regime and would be expected to increase the value of imputation credits to investors, particularly those investors that previously had imputation credits in excess of their tax liabilities. The AER considers that dividend drop-off study estimates for the post–2000 period should be employed for the purposes of estimating theta. Beggs and Skeels (2006) post–July 2000 theta estimate combined with a payout ratio of approximately 70 per cent gives an overall gamma estimate of 0.4.

The AER notes several regulators, prior to the AER's WACC review adopted a gamma of 0.5, which has been highlighted by ACG.[262] Taking account of the currently available information, the AER considers a reasonable range for gamma is 0.4–0.5. Based on this range, the AER considers a gamma of 0.45 to be the best estimate in the circumstances, especially given the limited reliable evidence currently available.

The AER considers that the adoption of a gamma of 0.45 for this draft decision is consistent with the revenue and pricing principles set out in section 24 of the NGL and will, or is likely to, contribute to the achievement of the national gas objective in section 23 of the NGL. For the final decision, to the extent that the Tribunal's decision on the further work in respect of gamma is available, the AER will take that into account and any other relevant new material to determine gamma for NT Gas's access arrangement.

6.5.5 Forecast tax allowance

In response to inquiries made by the AER into NT Gas's proposed capex, NT Gas submitted another version of their PTRM which contained updated values of the tax allowance.[263] These values are set out in table 6.3. Due to these changes and the various other changes that affected NT Gas's proposed revenues and or costs, the

259 ACG, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation*, 11 February 2011, pp. 7–8.

260 NTMEU, *Submission to the AER*, February 2011, p. 56.

261 Synergies, *Estimating a WACC for the NT gas transmission pipeline*, December 2010, p. 81.

262 ACG, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation*, 11 February 2011, pp. 7–8.

263 NT Gas, Email to AER, *Re. AER.NTGAS.05*, 9 February 2011, attachment.

AER has recalculated the forecast tax allowance for the access arrangement period, as shown in table 6.5.

Table 6.5: AER tax allowance for the access arrangement period ($'000, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Tax	0	902	1186	1204	704

Source: AER analysis

6.6 Conclusion

The AER has accepted the tax method proposed by NT Gas. However, due to changes in gamma, the opening TAB as at 1 July 2011, remaining tax asset lives, the tax loss carried forward as at 1 July 2011 and the various other factors that impact on revenues and costs, the forecast tax allowance for the access arrangement period has been amended. The AER considers this amended forecast tax allowance can be included as a building block for revenues under r. 76(c) of the NGR.

6.7 Required amendments

Before its access arrangement proposal and access arrangement information can be accepted, NT Gas must make the following amendments:

Amendment 6.1: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of a gamma of 0.45.

Amendment 6.2: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of the revised tax allowance in table 6.5 of this draft decision.

Amendment 6.3: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of the tax loss carried forward of $7.8 million as shown in table 6.4.

7 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital costs incurred by a service provider in the provision of transmission pipeline services. This expenditure also includes costs incurred in increasing long term demand for pipeline services and otherwise developing the market for pipeline services. The AER has reviewed NT Gas's proposed opex and requires various amendments to NT Gas's proposed overhead costs, marketing costs, and operations and maintenance step changes.

NT Gas has applied a base year roll forward method of forecasting opex. It proposed opex of $73 million ($2010–11) over the access arrangement period, representing a real increase of 59 per cent on average actual incurred expenditure in the earlier access arrangement period.[264] *The increase has been principally substantiated by a change in the overheads category resulting in significant increases in corporate overheads as well as increases in operation and maintenance costs.*

The AER reviewed NT Gas's forecast and its constituent components under its roll forward method against the NGR and the NGL. The AER engaged independent consultants Wilson Cook to provide expert engineering advice on the prudence and efficiency of NT Gas's proposed opex and Deloitte Access Economics to provide expert economic advice on the reasonableness of NT Gas's forecast labour costs.

Having considered this advice together with internal analysis, the AER considers that NT Gas's proposed opex is not prudent and efficient as required by the NGR. Overall, the AER accepts $59 million ($2010–11) in opex over the access arrangement period, which represents a 20 per cent decrease on proposed expenditures. On average, the accepted increase is 27 per cent higher than average annual expenditure in the earlier access arrangement period.

7.1 Introduction

This chapter sets out NT Gas's opex proposal, and the AER's analysis and considerations of the proposal and submissions from interested parties.

7.2 Regulatory requirements

Rule 91 of the NGR provides that opex must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

The access arrangement information for an access arrangement proposal must include opex (by category) over the earlier access arrangement period, a forecast of opex over the access arrangement period, and the basis on which the forecast has been derived.[265]

264 Incurred expenditure in the earlier access arrangement period has been adjusted to compare with the five year access arrangement period.

265 NGR, r. 72(1)(a)(ii) and r. 72(1)(e).

Any forecast or estimate must be supported by a statement setting out the basis of the forecast or estimate.[266] A forecast or estimate, must be arrived at on a reasonable basis, and must represent the best forecast or estimate possible in the circumstances.[267]

The access arrangement information must include the key performance indicators to be used by the service provider to support expenditure to be incurred over the access arrangement period.[268]

7.3 Access arrangement proposal

7.3.1 Earlier access arrangement

NT Gas's actual and estimated total opex over the earlier access arrangement period was $92 million ($2010–11), which is $4.9 million ($2010–11) less than that approved by the ACCC in 2002.[269] Table 7.1, disaggregates this expenditure by category showing that the under-spend was largely related to expenditure on overheads.

Table 7.1: NT Gas allowed vs. incurred opex over the earlier access arrangement period ($'000, 2010–11)

		2001–02	2002–03	2003–04	2004–05	2005–06
Operations & maintenance	Allowed	6860	7051	8769	7891	7648
	Incurred	7069	7855	8245	7239	7417
	Variance (%)	103	111	94	92	97
Overheads	Allowed	1733	1727	1725	1723	1697
	Incurred	1351	1447	1511	1191	1213
	Variance (%)	78	84	88	69	72
Sales & marketing	Allowed	176	176	176	176	174
	Incurred	243	130	73	111	55
	Variance (%)	138	74	41	63	32
Total operating expenditure	Allowed	8770	8955	10 670	9790	9518

266 NGR, r. 74(1).

267 NGR, r. 74(2).

268 NGR, r. 72(1)(f).

269 NT Gas, *Access arrangement submission*, December 2010, p. 118.

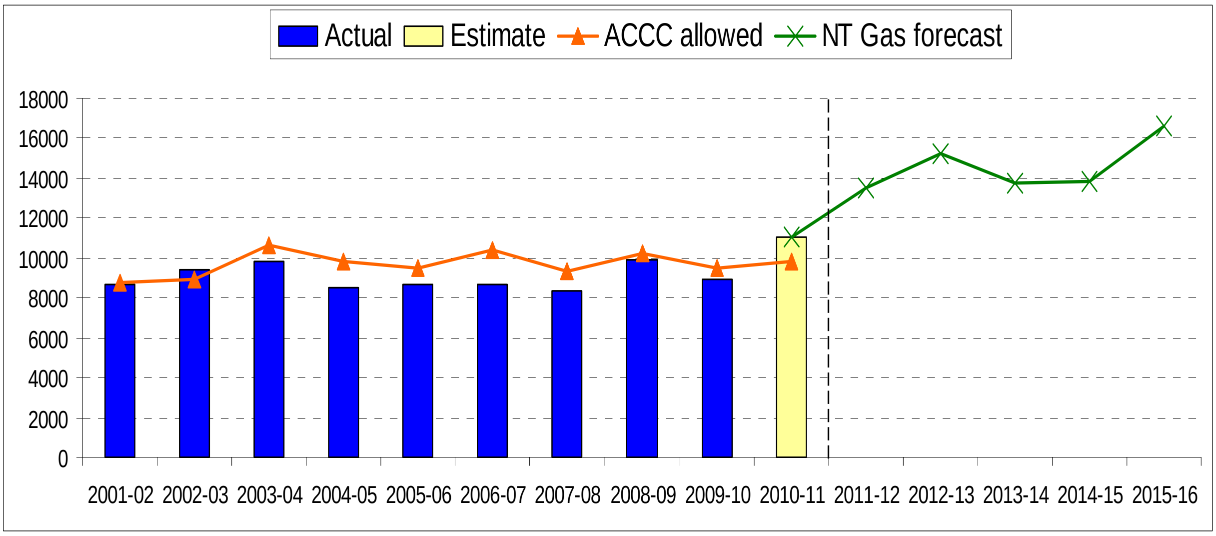
Incurred	8663	9432	9828	8540	8686	
Variance (%)	99	105	92	87	91	

		2006–07	2007–08	2008–09	2009–10	2010–11	Total 2001–11
Operations & maintenance	Allowed	8528	7461	8397	7609	7908	78 120
	Incurred	7380	7022	8452	7469	9002	77 149
	Variance (%)	87	94	101	98	114	99
Overheads	Allowed	1702	1667	1681	1670	1710	17 035
	Incurred	1236	1271	1413	1352	1967	13 952
	Variance (%)	73	76	84	81	115	82
Sales & marketing	Allowed	174	171	173	172	176	1749
	Incurred	47	48	38	61	61	867
	Variance (%)	27	28	22	35	34	50
Total operating expenditure	Allowed	10 404	9299	10 252	9451	9794	96 903
	Incurred	8663	8341	9904	8883	11 029	91 968
	Variance (%)	83	90	97	94	113	95

Source: NT Gas, *Access arrangement submission,* December 2010, p. 140.

Figure 7.1 compares NT Gas's actual opex in the earlier access arrangement period with that approved by the ACCC, as well as NT Gas's proposed opex for the access arrangement period.

Figure 7.1: Historic (actual vs. approved) vs. proposed opex ($'000, 2010–11)



Source: NT Gas, *Access arrangement submission*, December 2010, p. 140; NT Gas, *Access arrangement information*, December 2010, p. 19.

7.3.2 Forecast operating expenditure

NT Gas's total forecast opex represents a 59 percent[270] increase on total incurred expenditure and a 51 percent[271] increase on total approved expenditure when compared to the earlier access arrangement period. Table 7.2, disaggregates NT Gas's proposed forecast opex by category.

Table 7.2: Proposed forecast opex for the access arrangement period ($'000, 2010–11)

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Overheads	4338	4400	4434	4469	5167	22 808
Sales & marketing	176	176	176	176	176	882
Operations & maintenance	8975	10 657	9152	9216	11 302	49 302
Total operating expenditure	**13 489**	**15 234**	**13 763**	**13 861**	**16 646**	**72 993**

Source: NT Gas, *Access arrangement information*, December 2010, p. 19.

NT Gas has not included debt raising costs as an opex item. Instead, NT Gas has proposed these costs be recognised in the cost of capital. While all references to opex in this chapter are exclusive of debt raising costs, the total revenue figures set out in chapter 8 present opex inclusive of debt raising costs. The AER's consideration of NT Gas's proposed debt raising costs is set out in appendix B.

For the access arrangement period, NT Gas has forecast operations and maintenance expenditure and local overheads expenditure using a base year roll forward

270 Incurred expenditure in the earlier access arrangement period has been adjusted to compare with the five year access arrangement period.

271 ACCC approved expenditure in the earlier access arrangement period has been adjusted to compare with the five year access arrangement period.

approach.[272] NT Gas proposed 2009–10 as the base year. It submitted that this year was chosen as it is the most recent complete year to the access arrangement period for which audited accounts were available.[273]

NT Gas has added to the base year costs forecasts of corporate overheads, insurance and regulatory costs based on known allocations and costs.[274] In addition, costs associated with sales and marketing have been derived using forecasts in the earlier access arrangement period but have not been escalated for labour costs.[275]

A breakdown of NT Gas's total proposed forecast overhead costs is set out in table 7.3.

Table 7.3: Total forecast overheads expenditure in the access arrangement period ($'000, 2010–11)

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Corporate overheads	2219	2281	2315	2350	2386	11 550
Local overheads	826	826	826	826	826	4128
Insurance	1293	1293	1293	1293	1293	6467
Regulatory submission	0	0	0	0	663	663
Total	**4338**	**4400**	**4434**	**4469**	**5167**	**22 808**

Source: NT Gas, *Access arrangement submission*, December 2010, p. 133.

Table 7.4, shows NT Gas's proposed step changes in its forecast operations and maintenance expenditure for the base year 2009–10 and the access arrangement period.

272 NT Gas, *Access arrangement submission*, December 2010, pp. 123,129.

273 NT Gas, *Access arrangement submission*, December 2010, p. 123.

274 NT Gas, *Access arrangement submission*, December 2010, p. 129.

275 NT Gas, *Access arrangement submission*, December 2010, p. 133.

Table 7.4: Proposed step changes for the base year 2009–10 and the access arrangement period ($'000, 2010–11)

	2009–10	2011–12	2012–13	2013–14	2014–15	2015–16	Total[a]
Increased integrity works	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Cathodic protection surveys	[c-i-c]						
Access lease fees	[c-i-c]						
Leasing of emergency response trucks		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]		[c-i-c]
SCADA	[c-i-c]						
Right of way erosion	[c-i-c]			[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
Battery replacement	[c-i-c]						
Above ground recoating		[c-i-c]		[c-i-c]		[c-i-c]	[c-i-c]
Intelligent pigging			[c-i-c]			[c-i-c]	[c-i-c]
Total step change expenditure	**279**	**186**	**1 780**	**185**	**157**	**2 151**	**4 458**

Source: NT Gas, *Access arrangement submission,* December 2010, attachment I, (confidential).
a. Total over the access arrangement period.

7.4 Submissions

The AER received three submissions in relation to NT Gas's opex. These were:

Northern Territory Major Energy Users (NTMEU) which submitted that:

- there appeared to be little reason for NT Gas's opex to increase by 40 per cent as there is virtually no expansion of the pipeline to justify any scale growth
- throughout the earlier access arrangement period NT Gas had consistently under-run both the ACCC allowance, and NT Gas's own forecasts provided evidence that the current opex was a reasonable allowance
- NT Gas has claimed massive increases in opex that would provide little benefit to users, and at the same time provided little justification as to why such large cost increases were needed or reasonable.[276]

Power and Water Corporation (PWC) which submitted that:

- while PWC has had an approval mechanism in place in respect of the service provider's expenditure, it refuted any inference that its approvals had represented an assessment as to the reasonableness of such expenditure
- the magnitude of the increase in corporate overheads was excessive largely due to the allocation methodology

276 NTMEU, *Submission to the AER*, February 2011, pp. 44-45.

- the forecast large increase in insurance premium was not explained
- the most useful form of benchmarking of performance would be against actual results of prior years. However forecasts included in the access arrangement proposal did not measure up well on these criteria.[277]

Northern Territory Treasury (NT Treasury) which submitted that:

- NT Gas had not made a sufficient case to establish that the substantial increase in its proposed operating expenditure was economically efficient
- NT Gas's underspend on the ACCC approved allowance and its own forecast for opex in the earlier access arrangement period indicated that its current operating allowance was sufficient to cover its expenditure. As such the NT Treasury recommended that the AER review the arguments behind the proposed significant cost increases.[278]

7.5 Consultant review

The AER engaged Wilson Cook, engineering consultants, to review whether the technical aspects of NT Gas's proposed opex are prudent and efficient. Wilson Cook noted that:

- it was questionable whether the level of increased labour allocation in the base year was required for ongoing maintenance
- several step changes and ad hoc expenditure items are added to the base year for operations and maintenance expenditure. However, apart from two pigging projects in 2012–13 and 2015–16, these were mostly minor in terms of cost and would meet Wilson Cook's criteria for step changes
- there was a substantial increase in corporate overheads in the access arrangement period and, given the quantum of the increase, the AER may wish to verify the basis of the forecasts
- sales and marketing expenditure was minimal in the earlier access arrangement period due to uncertainty over the availability of gas. However it was reasonable to expect the forecast to increase back to previous levels given gas supply had been augmented. Sales and marketing expenditure accounted for only 1 per cent of total opex.[279]

7.6 AER's analysis and considerations

The AER considers that NT Gas's proposed forecast opex is too high and does not meet the requirements of the NGR. The AER has accepted the forecast opex of $59 million ($2010–11), which is 20 per cent less than that proposed by NT Gas. The AER's reasoning for the required amendments to the forecast opex are set out below against following headings:

277 PWC, *Submission to the AER*, March 2011.

278 NT Treasury, *Submission to the AER*, March 2011.

279 Wilson Cook, *Report – NT Gas*, January 2011, pp. 1–2.

- base year selection and adjustments
- real labour cost escalators
- specific opex forecasts
    - overheads expenditure
    - sales and marketing expenditure
    - operations and maintenance step changes

7.6.1 Base year selection and adjustments

Base year selection

The AER accepts NT Gas's proposal to use 2009–10 as the base year to forecast opex over the access arrangement period. In accepting 2009–10 as the base year, the AER has given consideration to the following:

- the level of base year expenditure is consistent with actual expenditure in the other years of the earlier access arrangement period. Both operations and maintenance, and overhead opex, are lower in the 2009–10 year than the preceding year, and expenditure in the 2009–10 year is also lower than the average for each year over the earlier access arrangement period
- the base year is sufficiently close to the access arrangement period to present an accurate reflection of NT Gas's operating and organisational circumstances. The 2009–10 year is also the closest year to the access arrangement period which is based on a full set of actual data.

The AER therefore considers that 2009–10 represents an efficient base year.

Base year adjustments

NT Gas has applied adjustments to the base year to take account of the abnormal level of labour allocations that were associated with work undertaken on non-regulated assets, as well as non-routine expenditure.[280] These adjustments are illustrated in figure 7.2.

280 NT Gas, *Access arrangement submission*, December 2010, pp. 123-124.

Figure 7.2: Proposed base year adjustments ($'000, 2010–11)

[c-i-c]

Source: NT Gas, *Access arrangement submission,* December 2010, attachment I, (confidential).

The AER considers that NT Gas's base year adjustments used to establish forecast expenditure represent expenditure that would be incurred by a prudent service provider as required under r. 91 of the NGR.

The AER considers that NT Gas's removal of non-routine expenditure from the base year satisfies the principle that the base year should not include substantial non-recurrent expenditure.

The most material base year adjustment is the addition of costs associated with labour that was previously allocated to unregulated capex works during 2009–10. Wilson Cook questioned whether this level of resource is required for ongoing maintenance work, and also noted that if there is no planned unregulated capex in the access arrangement period the total level of resource and expenditure may be greater than required for just maintenance.[281] The NTMEU also submitted that where staff can be redeployed for such significant periods, then it raises the question as to whether those staff are needed in relation to the regulated services.[282]

The AER requested that NT Gas provide details of the deployment of labour to maintenance work and questioned why the additional labour added to the base year is required in the access arrangement period.[283] In response NT Gas submitted that some projects and activities were deferred during the earlier access arrangement period (in line with risk management assessment) to 2010–11 and into the access arrangement period as they could not be undertaken within available labour resources. This deferral

281 Wilson Cook, *Report – NT Gas*, January 2011, p. 1.

282 NTMEU, *Submission to the AER*, February 2011, p. 29.

283 AER, Email to NT Gas, *Follow up questions to the information session (*28/01),31 January 2011, p. 1.

was largely related to direct current voltage gradient (DCVG)[284] dig-ups, which are now required.[285]

NT Gas also submitted that ongoing increased integrity works reflected in forecast expenditure also account for the need for the increased available labour resources associated with a reduction in works on unregulated assets. NT Gas does not anticipate that it will increase employee numbers to account for these increased works, and instead expects to fully deploy existing labour resources to work on regulated assets at this increased level.[286] NT Gas further submitted that future developments of or related to unregulated assets will be completed entirely by contracted or dedicated labour resources.[287]

NT Gas has deferred projects such as DCVG dig-ups from the earlier access arrangement period due to the shortage of labour resources and accepts that the normal level of labour resources will be required to undertake these activities during the access arrangement period. The AER is also satisfied that NT Gas will not redeploy labour resources to unregulated assets given that NT Gas will use other contracted or dedicated labour resources.

7.6.2 Real labour cost escalators

The AER does not accept that NT Gas's proposed real labour cost escalators allow for a forecast to be arrived at on a reasonable basis, as required under r. 74(2)(a) of the NGR. The AER has come to this conclusion for the following reasons:

- the forecasting methodology is not sufficiently rigorous
- the proposed labour cost index measure is inappropriate
- the escalators do not properly account for productivity effects, and therefore do not distinguish between wages and labour costs.

The AER's assessment of real cost escalators has been considered under the following headings:

- forecast methodology and its application
- choice of index measure
- accounting for productivity effects

Forecast methodology and application

NT Gas proposed to escalate opex and outsourced capex labour costs by 4 per cent nominally (or around 1.5 per cent real) in each year of the access arrangement

284 NT Gas, *Access arrangement submission*, December 2010, p. 70. A type of survey undertaken to identify potential areas of pipeline corrosion. .

285 NT Gas, Email to AER, *AER.NTGAS.03-14*, 8 February 2011, p. 5.

286 NT Gas, Email to AER, *AER.NTGAS.03-14*, 8 February 2011, p. 5.

287 NT Gas, Email to AER, *AER.NTGAS.03-14*, 8 February 2011, pp. 4-5.

period.[288] This figure was determined by calculating a five year historical average and applying its own judgement that the average input cost escalation over the access arrangement would be slightly less than over 2005–10.

The AER does not accept NT Gas's proposed forecast methodology, as it is neither arrived at on a reasonable basis, nor represents the best forecast possible in the circumstances. While the AER accepts the validity of the noted environmental and historical factors, the AER does not consider that judgement alone is a reasonable basis on which to forecast real escalation of costs. NT Gas's proposed annual tariff variation mechanism provides for the annual escalation of costs by CPI. In order to accept real deviation of input costs from CPI, a rigorously derived forecast series of cost growth projections would have to be derived with a rigorous methodology that satisfies r. 74 of the NGR. Consequently, the AER has only accepted labour cost escalator forecasts where they have been derived based on an established macroeconomic model.[289]

The AER accepts NT Gas's proposed breakdowns of opex and capex into labour costs and other costs. NT Gas has indicated that its labour cost breakdowns were confidential, including detailed on the application methodology.[290] The breakdowns proposed by NT Gas are based on actual labour and other cost splits from a sample of projects.[291] They are broadly consistent with the AER's expectations of cost breakdowns for gas service providers. Specifically, NT Gas proposed that labour escalation be applied to:

- 68 per cent of operating and maintenance roll forward expenditure
- 100 per cent of corporate overheads and regulatory costs
- 30 per cent of capex projects.[292]

However, the AER does not accept NT Gas's proposal that all labour costs should be escalated in line with the electricity, gas and water (EGW) sector labour cost growth.[293] In the AER's recent draft decision for the Queensland and South Australian gas distribution businesses, labour costs were disaggregated into EGW labour; construction labour; and general labour.[294] For APT Allgas, the AER determined specific application rates for the labour categories to opex and capex.[295] These application rates were based on a weighted average of the detailed cost breakdown provided by Envestra Queensland.[296] The AER considers that these application

288 NT Gas, *Access arrangement submission*, December 2010, pp. 86.

289 Such as Access Economics's AEM model, see: Access Economics, Forecast growth in labour costs (Qld & SA), November 2010, p. 98.

290 NT Gas, Email to AER, *AER.NTGAS.27*, 23 February 2011 (confidential).

291 NT Gas, *Access arrangement submission*, December 2010, p. 86.

292 NT Gas, Email to AER, *AER.NTGAS.27*, 23 February 2011(confidential).

293 NT Gas, *Access arrangement submission*, December 2010, p. 86.

294 AER, AER, *Draft decision–APT Allgas*, February 2011, p. 142; AER, *Draft decision–Envestra's SA network*, February 2011, p. 150.

295 AER, *Draft decision–APT Allgas*, February 2011, p. 92.

296 AER, *Draft decision–APT Allgas*, February 2011, p. 92.

rates— as set out in table 7.5 — are a reasonable estimate of the breakdown of the sectoral labour composition for NT Gas's opex and capex.

Table 7.5: AER conclusion on NT Gas real input cost escalator application rates as a proportion of total labour costs (per cent)

	Opex	Capex
EGW labour	0.82	0.10
General labour	0.18	0.02
Construction labour	0	0.88

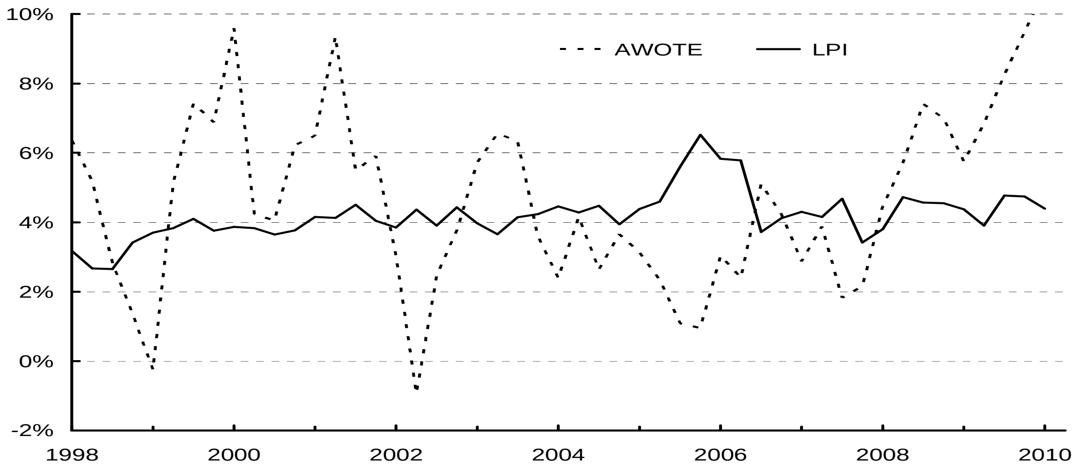
Source: AER Analysis

Choice of index measure

The AER considers that the Labour Price Index (LPI) is the appropriate measure on which to forecast labour prices for the purpose of real cost escalation. The AER's reasons for this were set out in detail in its decision for the Victorian electricity distribution businesses.[297] In contrast, NT Gas has proposed escalators based on the AWOTE measure of wage growth.

The AWOTE index is designed to reflect the average wages earned by a worker in a segment of the economy, in this case by state and by sector. The primary difference between AWOTE and the LPI is the influence of compositional shifts in employment. Changes in the composition of the workforce in terms of seniority, occupations within an industry sector or gender distribution are all reflected in the AWOTE index. By comparison the LPI reflects the growth in the price of labour based on costs of fixed levels of 'skill' and is unaffected by compositional shifts. The AER considers that the sensitivity of AWOTE to compositional effects is problematic in the context of forecasting labour cost escalators—as set out in figure 7.3.

Figure 7.3: Growth in AWOTE and LPI, Australian utilities sector[298]



297 AER, *Victorian Final Decision 2011-2015 - Appendix K*, October 2010, p. 246.

298 ABS and AER analysis.

Figure 7.3 sets out the progression of LPI and AWOTE in the national EGW sector over time. The observable volatility in the AWOTE series is likely to be even further exaggerated at the state-sectoral level as the sample sizes in the surveyed businesses decrease. In its report, Access Economics noted that the analysis of compositional shifts is sometimes relevant when analysing the wage progression of the whole Australian economy.[299] However, at this level of disaggregation, the AER considers the benefits from this analysis are clearly outweighed by the volatile series it produces.

The AER accepts the advice of Access Economics, from a previous report to the AER, that using AWOTE is unlikely to provide a reasonable reflection of the true movements in the price of labour faced by a service provider. Further, the AER considers that the pronounced volatility associated with the AWOTE is unlikely to represent a reasonable basis for a forecast, or to produce the best forecast possible in the circumstances. As such, the AER considers that NT Gas's forecast is not representative of the efficient costs it is likely to face, and the AER is not satisfied that the labour cost escalators meet the requirements of r. 74 of the NGR. A similar analysis would apply to r. 79(1) and r. 91 of the NGR.

Productivity effects

It is widely accepted that productivity is a key driver of movements in relative wages. Access Economics accounts for the effect of productivity in its wage forecasting model by assuming that more productive workers will be compensated with higher wages.[300] It also accounts for productivity effects on the cost of labour per unit of output by applying post-forecast adjustments, to reflect the assumption that a more productive workforce will produce the same unit of output of labour at a lower cost.

In effect:

- positive productivity growth will result in higher individual wages, but will lead to a corresponding reduction in the labour requirement to produce a level of output, reducing labour costs

- negative productivity growth will slow individual wage growth, but will increase the labour requirement to produce a level of output, increasing labour costs.

Table 7.6 sets out the forecasts of productivity adjusted real LPI forecasts (labour costs) compared to productivity unadjusted LPI forecasts (individual wages). Access Economics has forecast positive productivity growth in all three sectors, which is consistent with economic recovery in the Northern Territories. As such, annual changes in labour costs are less than forecast changes in individual wages.

299 Access Economics, *Forecast growth in labour costs (Qld & SA)*, November 2010, p. 89.

300 Access Economics, *Forecast growth in labour costs (Qld & SA)*, November 2010, p. 103.

Table 7.6: AER conclusion on NT Gas's disaggregated real labour cost growth (per cent)

	2011–12	2012–13	2013–14	2014–15	2015–16
	Productivity adjusted real LPI				
EGW labour	-0.2	-0.1	0.1	-0.8	-1.4
General labour	-1.2	-1.2	-0.6	-1.3	-1.7
Construction labour (capex only)	0.8	0.6	0.6	-0.4	-0.9
	Productivity unadjusted real LPI				
EGW labour	1.7	1.6	1.9	2	1.5
General labour	0.2	0.9	1.4	1	0.7
Construction labour (capex only)	1.8	2.3	2.3	2	1.3

Source: Deloitte Access Economics, *Northern territories LPI growth*, March 2011, p. 4.

This productivity adjustment is necessary in forecasting labour cost escalation, because NT Gas's required units of labour are a function of the work NT Gas undertakes. NT Gas targets a particular level of labour output, as opposed to choosing a desired number of employees and planning work output accordingly. Real labour cost escalators should therefore address labour costs per unit of output, rather than per individual employee.

The AER considers the assumptions made by Access Economics reasonably reflect the offsetting impacts of productivity on wages and overall unit costs of labour. The AER further considers that Access Economics' forecasts of real state-sectoral LPI growth with productivity adjustments are arrived at on a reasonable basis and represent the best forecast possible in the circumstances, as required by r. 74 of the NGR.

7.6.2.1 AER's estimated real labour cost escalators

The AER engaged Deloitte Access Economics[301] to prepare forecasts of Northern Territories labour cost growth in the utilities; administrative and support services; and construction labour sectors. Deloitte Access Economics noted the following about labour cost growth in the NT:

- growth in the NT is largely project based, with a number of large projects in planning, but not expected to commence in the immediate future
- the NT has strong growth potential, but is currently growing slowly due to being 'between projects'

301 The AER previously engaged Access Economics to produce a number of reports for the AER on labour cost escalation, including for the ongoing Queensland and South Australia gas distribution AAR. Since the publication of the Qld/SA draft decisions, Access Economics was taken over by Deloitte. Work undertaken by the consultant since this time is referenced as Deloitte Access Economics.

- despite this slower growth, local LPI has continued to outpace national LPI growth, due to the lingering effects of EBAs and other work from the previous round of projects.[302]

The AER considers the subsequent forecasts are arrived on a reasonable basis, and are the best forecasts possible in the circumstances— as required under r. 74 of the NGR. The forecasts are set out in table 7.6.

Table 7.6: AER conclusion on NT Gas's disaggregated real labour cost growth (per cent)

	2011–12	2012–13	2013–14	2014–15	2015–16
EGW labour	-0.2	-0.1	0.1	-0.8	-1.4
General labour	-1.2	-1.2	-0.6	-1.3	-1.7
Construction labour (capex only)	0.8	0.6	0.6	-0.4	-0.9

Source: Deloitte Access Economics, *Northern territories LPI growth*, March 2011, p. 4.

7.6.2.2 AER conclusion on input cost escalators

The AER considers that NT Gas's proposed real cost escalators have not been estimated on a reasonable basis nor produce the best forecast in the circumstances faced by NT Gas. In particular, the AER considers:

- LPI, not AWOTE, is the correct index on which to base forecasts of labour cost escalation: because of its suitability at the required level of state–sectoral disaggregation. As such, NT Gas's forecast methodology is neither arrived at reasonable basis, nor produces the best forecast possible in the circumstances

- NT Gas has not sufficiently compensated for the effect of productivity on labour costs, as opposed to wage rates.

The AER does not approve NT Gas's real cost escalators and requires NT Gas to amend its escalator forecasts, such that:

- The AER's amended input cost escalators are applied as set out in table 7.6

- These should be applied to overall opex and capex in line with NT Gas's proposed labour-materials breakdowns.

302 Deloitte Access Economics, *Northern territories LPI growth*, March 2011, pp. 1–2.

Table 7.6: AER conclusion on NT Gas aggregated real labour cost escalators (per cent)

	2011–12	2012–13	2013–14	2014–15	2015–16
Opex labour	-0.38	-0.30	-0.03	-0.89	-1.45
Capex labour	0.66	0.49	0.53	-0.46	-0.97

7.6.3 Specific operating expenditure forecasts

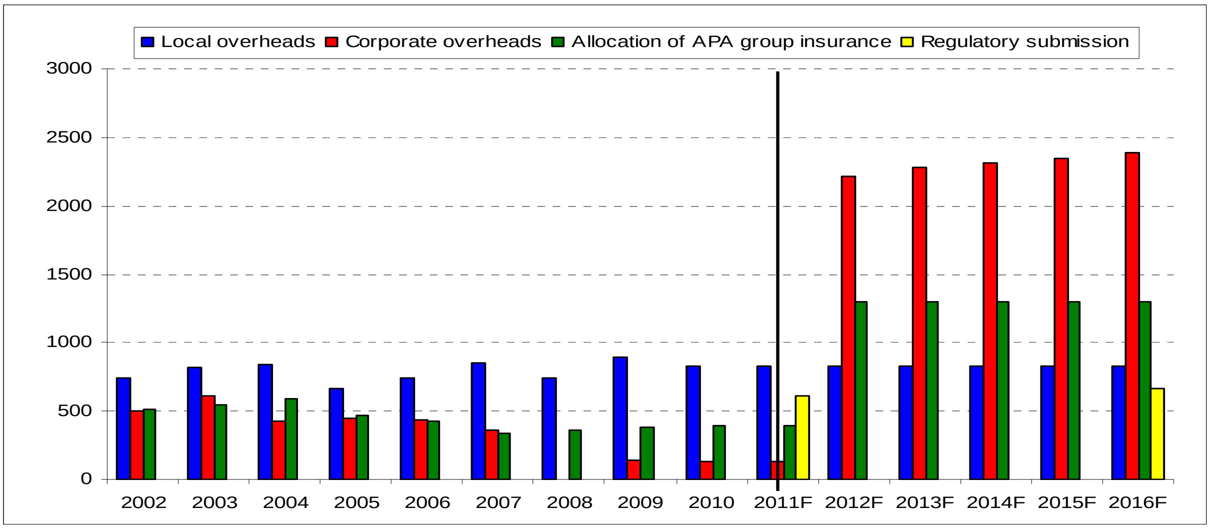
7.6.3.1 Overheads expenditure

The AER does not approve NT Gas's proposed forecast corporate overhead costs or insurance costs as they are not consistent with r. 74 and r. 91 of the NGR. The AER accepts that NT Gas's proposed local overheads and regulatory costs are consistent with the NGR.[303]

NT Gas's proposed overhead costs represent a significant step increase when compared to actual expenditure in the earlier access arrangement period. Corporate overhead costs and insurance costs are the largest contributors to this overall increase.

A comparison of actual overhead expenditure in the earlier access arrangement period and forecast overhead expenditure in the access arrangement period is set out in figure 7.4.

Figure 7.4: NT Gas actual overhead costs versus forecast overhead costs ($'000, 2010–11)



Source: NT Gas, *Email response AER.NTGAS.03–14,* 31 January 2011, p. 7; NT Gas, *Access arrangement submission,* December 2010, p. 133.

In reviewing the proposed overhead costs, the AER considered:

303 NGR, r. 74(2) and r. 91.

- how the components of overhead costs relate to the provision of pipeline services[304]

- whether any of the overhead costs would be recovered elsewhere – that is, potential for double counting

- whether the overhead costs proposed by NT Gas are reasonable.

The AER's analysis and consideration of each of NT Gas's proposed overhead expenditure categories is set out below.

Corporate overheads
The AER considers that the proposed forecast opex related to corporate overheads has not been made on a reasonable basis, does not represent the best forecast or estimate possible under r. 74 of the NGR and that this expenditure does not meet the opex criteria under r. 91 of the NGR. The AER proposes not to accept NT Gas's proposed forecast corporate overheads is due to the double counting of costs contained within local overheads. Instead, the AER accepts a reduced forecast corporate overhead expenditure that has been adjusted to remove the double counting.

The AER expressed concerns to NT Gas regarding the significant increase in corporate overheads when compared with forecast expenditure in the earlier access arrangement period. Similar concerns were raised by the NTMEU in its submission to the AER.[305] In response to the AER, NT Gas submitted that in the earlier access arrangement period, a number of corporate functions were carried out independently in the Northern Territory (NT) and therefore were not included in the corporate overheads allocation.[306]

NT Gas submitted that several functions are now becoming increasingly centralised and will therefore be charged through APA. For example, a consistent finance system is now used across APA (including NT Gas) which is administered centrally, replacing the former stand alone system in the NT. In addition, human resource functions such as leadership and mentoring training are now arranged centrally. Also the pipeline will no longer be governed by an independent board at the end of the current finance lease.[307]

Given the shift in the costs attributable to the above functions from NT Gas to APA, the AER would expect to see a reduction in local overhead expenditure to offset the increase in corporate overheads. However, local overheads are forecast to remain consistent with previous levels. Consequently, if a higher than normal local overhead is required to be maintained, the AER considers this would then imply less use of the head office services. Wilson Cook supported this view and, further, outlined that this would mean that an allocation of head office costs on a similar basis to other entities in the group may lead to some double counting. Wilson Cook considered that an

304 NGL, s. 2 and s. 23.

305 NTMEU, *Submission to the AER*, February 2011, pp. 41-42.

306 NT Gas, Email to AER, *AER.NTGAS.21-34*, 15 February 2011, pp. 3-4.

307 NT Gas, Email to AER, *AER.NTGAS.21-34*, 15 February 2011, p. 4.

allocation basis that recognises the increased level of local management would be appropriate.[308] The AER agrees with Wilson Cook's view.

NT Gas submitted that the costs for various APA functions included in corporate overheads were allocated to individual operating pipelines, including the AGP, based on an allocation process which:

- assigned any directly attributable costs to the relevant asset
- allocated costs to assets based on causal allocators where possible, and
- allocated remaining costs based on APA's individual assets' budgeted revenues.[309]

Based on expected revenues for 2010–11 the general allocator for the AGP is 4.2 per cent.[310]

In its submission, PWC submitted that the magnitude of corporate overheads proposed by NT Gas is excessive due to the allocation methodology.[311]

The AER considers that the overall allocation approach is consistent with previous AER/ACCC decisions. However, the AER does not consider it is appropriate in the case of NT Gas to use a general allocator to allocate overhead costs. This is because the AER considers that a number of corporate functions, including accounting and engineering functions which are normally undertaken by APA are, in the case of NT Gas, undertaken locally and are therefore already included in local overheads. Using a general allocator to allocate overheads to NT Gas will result in double counting of functions that are undertaken by APA on behalf of other entities in the group but which are not undertaken on behalf of NT Gas. The large increase in total overhead costs, when compared with the earlier access arrangement period, may indicate that the level of double counting is likely to be substantial.

In its access arrangement proposal NT Gas has provided limited information for the AER to determine what proportion of APA corporate functions should be allocated to NT Gas. Given these circumstances the AER considers that the best method to remove double counting is to deduct the amount of local overhead costs from the corporate overhead general allocation amount.

Local overheads

The AER proposes to accept NT Gas's proposed forecast local overheads. The AER considers that the proposed forecast opex related to local overheads has been made on a reasonable basis, represents the best forecast or estimate possible in accordance with r. 74 of the NGR, and meets the opex criteria under r. 91 of the NGR.

NT Gas submitted that it has used the 2009–10 expenditure as the basis for forecasting local overheads over the access arrangement period.[312] However, NT Gas

308 Wilson Cook, *Email response re Amadeus,* 8 March 2011.

309 NT Gas, *Access arrangement submission,* December 2010, p. 131.

310 NT Gas, *Access arrangement submission,* December 2010, p. 131.

311 PWC, *Submission to the AER*, March 2011.

312 NT Gas, *Access arrangement submission*, December 2010, p. 129.

provided little detailed information on local overhead expenditure in its access arrangement proposal.

On request from the AER, NT Gas provided more detail to support its forecast local overhead expenditure.[313] NT Gas submitted that because of its remote location it must maintain a senior management structure in the NT. This is to ensure appropriate corporate and financial governance and responsibility is maintained in the NT. NT Gas also submitted it is necessary to maintain senior engineering, marketing, and commercial staff, as well as local accounting and procurement functions.[314]

The AER considers it is reasonable to expect that NT Gas's level of local overheads is affected by the remoteness of the AGP. The AER also considers that the activities which are included in the proposed local overheads relate to the provision of pipeline services.[315] However, if such an activity is undertaken at the local level rather than normally expected at the corporate level, care must be taken to ensure that there is no double counting of costs. NT Gas's proposed forecast local overheads expenditure is consistent with the actual level of expenditure incurred in 2009–10.

Insurance

The AER considers that NT Gas's proposed forecast opex related to insurance costs has not been made on a reasonable basis, and does not represent the best forecast or estimate possible under r. 74 of the NGR and that this expenditure does not meet the opex criteria under r. 91 of the NGR. The AER proposes not to accept NT Gas's proposed forecast insurance costs as NT Gas has provided insufficient information to support its proposal for higher insurance costs.

NT Gas did not provide any information in its access arrangement proposal in relation to its forecast increase in insurance costs. In response to an information request from the AER, NT Gas provided limited information in relation to its proposed forecast insurance costs. This information consisted of an insurance estimate used to derive its forecast.[316]

The NTMEU submitted that NT Gas has not made any observation as to what extent the insurance costs have risen above the amount already included in base year costs. The NTMEU submitted that the amount calculated for insurance using a zero base approach must be reduced by the amount NT Gas has been paying for insurance that is already part of its actual overheads expenditure.[317] PWC also submitted that the forecast large increase in insurance premium is not explained.[318]

The AER considers that NT Gas has not provided any qualitative explanation as to why forecast insurance costs will rise dramatically when compared to actual expenditure in the earlier access arrangement period. Further, NT Gas has not provided any information to indicate whether these costs have been allocated wholly to NT Gas, or whether they apply and can be allocated to other APA businesses.

313 NT Gas, Email to AER,*AER.NTGAS.21-34*,, 15 February 2011, pp. 3-4.

314 NT Gas, Email to AER,*AER.NTGAS.21-34*,, 15 February 2011, p. 4.

315 NGL, s. 2 and s. 23.

316 NT Gas, Email to AER,*AER.NTGAS.21-34,* 15 February 2011, p. 4.

317 NTMEU, *Submission to the AER*, February 2011, pp. 41-42.

318 PWC, *Submission to the AER*, March 2011, p. 9.

Regulatory costs
The AER considers that the proposed forecast opex related to regulatory costs has been made on a reasonable basis, represents the best forecast or estimate possible under r. 74 of the NGR, and meets the opex criteria under r. 91 of the NGR. For these reasons, the AER proposes to accept NT Gas's proposed forecast regulatory costs.

NT Gas has proposed regulatory costs in 2015–16 to cover the completion of its regulatory submission in accordance with its obligations under the revised access arrangement.[319]

The NTMEU submitted that although the costs appear high, NT Gas's approach to regulatory costs seems reasonable.[320]

In response to an information request from the AER in relation to overhead costs, NT Gas submitted that for the earlier access arrangement period, its regulatory costs are estimated to be $0.6 million ($2010–11).[321] In considering NT Gas's forecast regulatory costs for the access arrangement period, the AER notes that these costs are comparable to the estimated regulatory costs that were incurred in the earlier access arrangement period.

7.6.3.2 Sales and marketing expenditure

The AER considers that the proposed forecast opex related to sales and marketing has not been made on a reasonable basis, does not represent the best forecast or estimate possible under r. 74 of the NGR, and does not meet the opex criteria under r. 91 of the NGR. However, the AER proposes to accept a reduced forecast sales and marketing expenditure which is based on NT Gas's estimated actual expenditure for 2010–11 ($0.06 million ($2010–11)). The AER considers that the 2010–11 estimate was probably made after the changed circumstances of the gas supply had occurred, and that NT Gas was aware of the likely impact of this changed circumstance when making this estimate.

NT Gas submitted that its forecast sales and marketing expenditure was derived in line with the forecast in the earlier access arrangement period. NT Gas also submitted that the base year approach was unsuitable to forecast its sales and marketing expenditure because actual expenditure in the earlier access arrangement period is highly atypical of expenditure to be expected in the access arrangement period due to the recent emergence of available gas and capacity on the pipeline.[322]

In its submission the NTMEU raised concerns about the level of proposed expenditure and noted that it is likely that only a small amount of gas will be contracted by new and existing users because the PWC will contract most of the capacity of the AGP.[323] PWC also submitted that about half of the increase in forecast opex was caused by a sudden increase in overheads and marketing costs. [324]

319 NT Gas, *Access arrangement submission,* December 2010, pp. 131-132.

320 NTMEU, *Submission to the AER,* February 2011, p. 39.

321 NT Gas, Email to AER, *AER.NTGAS.03-14, 19-20*, 8 February 2011, p. 7.

322 NT Gas, *Access arrangement submission,* December 2010, p. 133.

323 NTMEU, *Submission to the AER,* February 2011, pp. 42–43.

324 PWC, *Submission to AER*, March 2011, p. 8.

The AER agrees with the concerns raised in submissions, and questions why such a large increase in sales and marketing expenditure is forecast, given that NT Gas is expecting the full capacity of the pipeline to be contracted to PWC. Further, it is forecasting no additional users on the pipeline during the access arrangement period.[325] Even with the increase in gas availability and pipeline capacity from 2009–10, PWC was the only significant user of the pipeline in the earlier access arrangement period. There were several other smaller users that had interruptible gas contracts that lasted between one and three years in the earlier access arrangement period.[326] Taking into account these factors, the AER considers that NT Gas has not provided sufficient justification of its proposed forecast increase in sales and marketing expenditure, when compared to that expenditure incurred in the earlier access arrangement period.

The AER also considers that it is inappropriate for NT Gas to base its forecasts on a forecast that was approved in 2003. The AER notes that circumstances have changed significantly since the forecast sales and marketing expenditure was approved by the ACCC for the earlier access arrangement period. This approved forecast expenditure took into account the likely depletion of the Mereenie and Palm Valley gas fields, but did not predict the discovery of the Blacktip gas field and the connection of the Bonaparte Gas Pipeline. For this reason, the AER does not consider it reasonable to provide forecast expenditure based on circumstances of an earlier access arrangement period when these circumstances have changed significantly.

7.6.3.3 Operations and maintenance step changes

The AER does not approve NT Gas's proposed step changes for increased integrity works and above ground station recoating as they are not consistent with r. 91 of the NGR. The AER accepts other proposed step changes as they are consistent with r. 74(2) and r. 91 of the NGR.

The AER's consideration of each of NT Gas's proposed step changes is set out in table 7.7.

325 NT Gas, *Access arrangement submission*, December 2010, p. 58.

326 NT Gas, *Access arrangement submission*, December 2010, p. 37.

Table 7.7: AER consideration of NT Gas's operations & maintenance step changes ($m, $2010–11)

Item of expenditure	Submissions	AER consideration
Increased integrity works – increased number of DCVG dig-up repairs (70 per annum) required to fix coating defects.[327]	The NTMEU submitted that it is not clear why more dig-ups are required than in the past, especially considering that the capex program has been massively increased in order to address the suspected breakdowns of the pipeline coatings. The NTMEU also submitted that an increase in capex should result in less opex, yet NT Gas has proposed more capex and an increase in opex to address this issue.[328]	As outlined in section 7.6.1, in approving the additional labour requirement in the base year, the AER has taken account of the need for additional labour to work on projects including DCVG dig-ups during the access arrangement period. Given the AER has approved an increase in base year costs on this basis, the AER considers that a step change for this work is not required. For this reason the AER proposes not to accept NT Gas's proposed step change for increased integrity works as it is not consistent with the NGR.[329]
Changed requirements for cathodic protection surveys – changes in equipment requirements means that a larger helicopter is now required to undertake surveys.[330]		The AER notes that this increase in costs is required for compliance with regulatory requirements which are outside the control of NT Gas. For this reason the AER considers that this step change is justified and accepts this expenditure as it meets the opex criteria under r. 91 of the NGR.
Access lease fees – forecast increase in fees paid to access pipeline easements.[331]	The NTMEU submitted that, as the pipeline has not increased in size, it seems strange that access fees would increase.[332]	The new access lease fees must be agreed for NT Gas to continue to operate the pipeline. [c-i-c].[333] On this basis the AER considers that the forecast expenditure related to access lease fees has been made on a reasonable basis, represents the best forecast or estimate possible under r. 74(2) of the NGR and that this expenditure meets the opex criteria under r. 91 of the NGR.
SCADA costs associated with asset changes – the addition of new delivery and supply points	The NTMEU submitted that while the addition of a new supply point might cause an increase in the capex to accommodate it, it is difficult to accept that this would impact long term daily	The AER accepts that an increase in the number of delivery and supply points leading to increased data points would require additional support and maintenance work. The AER also considers that it is reasonable to expect a rise in contract prices given that additional

327 NT Gas, *Access arrangement submission*, December 2010, p. 125.

328 NTMEU, *Submission to the AER*, February 2011, pp. 29-30.

329 NGR, r. 91.

330 NT Gas, *Access arrangement submission*, December 2010, p. 125.

331 NT Gas, *Access arrangement submission*, December 2010, p. 125.

332 NTMEU, *Submission to the AER*, February 2011, pp. 30-31.

333 NT Gas, Email to AER, *AER.NTGAS.21-34*, 15 February 2011, pp. 1-2.

has led to increased support and maintenance costs.[334]	operations and maintenance charges.	support and maintenance work will be undertaken. As such, the AER considers that forecast expenditure related to SCADA costs meets the opex criteria under r. 91 of the NGR.
Replacement of emergency response trucks.[335]	The NTMEU submitted that NT Gas had previously allowed for the capex needed to replace the emergency response trucks but by not replacing these trucks under the capex program, NT Gas has made a windfall profit by not expending the capital allocated for this purpose. The NTMEU also submitted that, providing there is no double up (claiming both capex and opex for these trucks), then this might be considered a step change.[336]	The AER sought clarification from NT Gas as to the calculation of the step change for the replacement of emergency response trucks. NT Gas submitted that the proposed costs for the replacement of emergency trucks include the fully kitted price of two trucks, lease costs for a four year lease term, and a residual amount. These costs have been included as opex and smoothed across the four year lease term (2011–12 to 2014–15).[337] On this basis the AER accepts that the forecast expenditure related to replacement of emergency response trucks has been made on a reasonable basis, represents the best forecast or estimate possible under r. 74(2) of the NGR and that this expenditure meets the opex criteria under r. 91 of the NGR.
Non annual expenditure – including right of way erosion, above ground station recoating, battery replacement, and intelligent pigging.[338]	The NTMEU submitted that it considers several of these step changes are already included in long term opex.[339] In regards to pigging, the NTMEU also submitted that if more frequent pigging is required then this is a step change, and the costs should be amortised over a shorter period. The NTMEU also submitted that pigging is not new in itself, it is only more frequent, therefore only the amortisation impact should be seen as a step change.[340]	The AER accepts all of the proposed non annual expenditure step changes except for above ground station recoating. The AER proposes not to approve the above ground station recoating expenditure because it considers that this expenditure is already included in the base year expenditure and is therefore not consistent with r. 91 of the NGR. The AER considers that the schedule submitted by NT Gas for recoating of meter stations would indicate that as a minimum one station will require recoating every second year for the life of the pipeline. Given that the AGP is more than ten to fifteen years old, the AER considers that this work would already be undertaken on one station every two years and is hence ongoing opex.

334 NT Gas, *Access arrangement submission*, December 2010, p. 126.

335 NT Gas, *Access arrangement submission*, December 2010, p. 126.

336 NTMEU, *Submission to the AER*, February 2011, pp. 31-32.

337 NT Gas, Email to AER, *AER.NTGAS.21-34*, 15 February 2011, p. 2.

338 NT Gas, *Access arrangement submission*, December 2010, p. 126.

339 NTMEU, *Submission to the AER*, February 2011, pp. 31-32.

340 NTMEU, *Submission to the AER*, February 2011, p. 32.

7.6.4 Benchmarking and efficiency

To support its proposed forecast opex, NT Gas has provided benchmarking data to illustrate that its base year expenditure is efficient.[341]

The NTMEU submitted that it agreed with NT Gas's assessment that NT Gas's 2009–10 opex is demonstrably efficient when compared to other pipelines. However it noted that even though the 2009–10 actual opex is seen as being efficient this does not mean that the forecast opex for the access arrangement period is also efficient.[342] Both the NTMEU and PWC also submitted that the best method of benchmarking for this type of business is against actual expenditure achieved in prior years.[343]

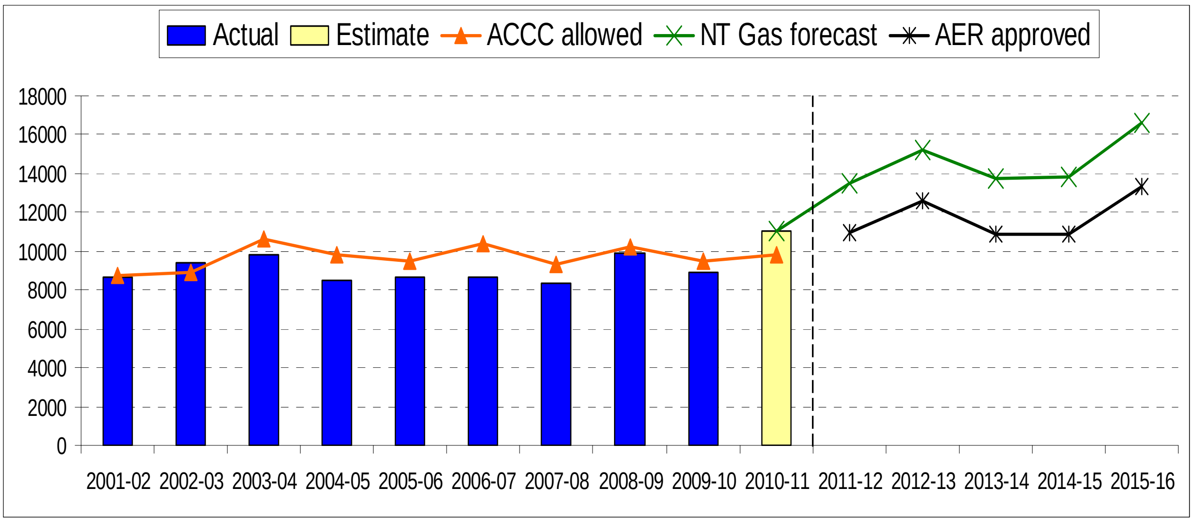
The AER acknowledges that there are various limitations to benchmarking given the different individual characteristics of other pipelines. For this reason the AER considers that benchmarking is best presented as an accompaniment to other substantiating analyses of operating costs.

7.7 Conclusion

The AER proposes to not approve of NT Gas's proposed forecast opex as it considers this expenditure does not comply with r. 91 of the NGR. Accordingly, the AER requires NT Gas to make the amendments set out in section 7.8 of this draft decision.

Overall, the AER approves $59 million ($2010–11) in opex over the access arrangement period as consistent with the NGR, which represents a 20 per cent reduction on proposed expenditures. The total approved opex against that proposed is set out in figure 7.5.

Figure 7.5: Historic (actual vs. approved) vs. proposed and approved opex ($'000, 2010–11)



Source: NT Gas, *Access arrangement submission*, December 2010, p. 140; NT Gas, *Access arrangement information*, December 2010, p. 19.

341 NT Gas, *Access arrangement submission*, December 2010, pp. 135-139.

342 NTMEU, *Submission to the AER*, February 2011, pp. 43-44.

343 NTMEU, *Submission to the AER*, February 2011, p. 44; PWC, *Submission to the AER*, March 2011.

7.8 Amendments required to the access arrangement proposal

Amendment 7.1: amend the access arrangement proposal and access arrangement information as necessary to reflect the adjustments made to proposed opex for the access arrangement period set out in table 7.7.

Table 7.8: AER required amendments to NT Gas's forecast opex ($'000, 2010–11)

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Total NT Gas proposed operating expenditure	13 489	15 234	13 763	13 861	16 646	**72 993**
AER specific amendments						
Operations & maintenance						
Step changes:[a]	-70	-40	-113	-85	-161	**-470**
Labour escalation	-196	-309	-393	-537	-754	**-2189**
Overheads[b]						
Corporate overheads[c]	-867	-901	-935	-970	-1005	**-4678**
Insurance	-1293	-1293	-1293	-1293	-1293	**-6467**
Marketing	-116	-116	-116	-116	-116	**-580**
Total AER specific amendments	-2543	-2660	-2851	-3001	-3329	**-14 384**
Total AER approved operating expenditure	**10 946**	**12 574**	**10 912**	**10 860**	**13 317**	**58 609**

a. The AER has accepted all of the proposed step changes except for increased integrity works and above ground station recoating.

b. The AER has accepted local overheads and regulatory costs and therefore no adjustments are required for these cost categories.

c. The AER has adjusted corporate overheads by subtracting the local overheads and adjusting for the affect of the AER's approved escalation applied to corporate overheads.

8 Total revenue

The AER calculates a total revenue requirement for NT Gas over the access arrangement period of $129.7 million, compared to $169.8 million ($2010–11) proposed by NT Gas. The main reasons for the difference are the reductions required by the AER to NT Gas's proposed WACC, and forecast opex over the access arrangement period.

Based on the AER's approved revenues and demand forecasts, the approved tariff for reference services is 24 per cent lower than the tariff proposed by NT Gas. The reference tariff is set to increase each year only by the rate of change in CPI.

8.1 Introduction

This chapter sets out the AER's estimation of annual revenue requirements for NT Gas's of the provision of pipeline services for each year of the access arrangement period. This chapter also sets out the X factors applied to NT Gas's reference tariffs as part of the estimation of the CPI adjustment.

8.2 Regulatory requirements

Rule 72(1)(m) of the NGR provides that the access arrangement information for a full access arrangement proposal must include the total revenue to be derived from pipeline services for each regulatory year of the access arrangement period.

Rule 76 of the NGR provides that total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:

- a return on the projected capital base for the year
- depreciation on the projected capital base for the year
- if applicable—the estimated cost of corporate income taxation for the year
- increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency
- a forecast of operating expenditure for the year.

8.3 Access arrangement proposal

The proposed total revenue requirement and the X factors for the AGP for each year of the access arrangement period are set out in Table 8.1.

Table 8.1: NT Gas's proposed annual revenue requirements and X factors ($m, nominal, unless otherwise stated)[a]

	2011–12	2012–13	2013–14	2014–15	2015–16
Total revenue building blocks					
Return on capital	12.8	13.4	13.1	12.9	12.5
Regulatory depreciation	4.6	3.8	4.1	4.4	1.0
Operating expenditure	13.8	16.0	14.8	15.3	18.8
Tax allowance	1.9	1.6	2.0	2.0	0.9
X factors(%)	na	0.0	0.0	0.0	0.0
Revenue requirement	33.1	35.0	34.0	34.6	33.2

Source: NT Gas, *Access arrangement information*, December 2010, p. 35, NT Gas, *Access arrangement submission*, December 2010, p. 148.

8.4 AER’s consideration

The total revenue building blocks proposed by NT Gas are addressed in the AER’s analysis and considerations in Part A of the draft decision.

8.4.1 P0 adjustment and X factors

The P0 adjustment indicates the increase in the total revenue requirement in the first year of the access arrangement period, while the X factors indicate subsequent movements in tariffs. The X factors are the smoothing adjustment to subsequent years required to maintain the present value of revenues.

8.4.2 Total revenue, P0 adjustment and X factors

The AER has estimated NT Gas’s total revenue, P0 adjustment and X factors based on its analysis and consideration of the building block components discussed in the chapters in Part A of the draft decision. These estimations are summarised in Table 8.2.

The AER’s draft decision results in a total revenue requirement over the access arrangement period of $129.7 million ($2010–11), compared to $169.9 million ($2010–11) proposed by NT Gas. The main reasons for the difference reflect the AER’s decision not to approve:

- the opex for the AGP
- the opening capital base for the AGP and reducing the forecast capital expenditure for the AGP
- the proposed WACC for the AGP.

Table 8.2: AER's conclusion on NT Gas's annual revenue requirements and X factors ($m, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Return on capital	9.4	9.9	9.8	9.7	9.5
Regulatory depreciation	3.5	2.9	3.1	3.3	0.9
Operating expenditure	11.3	13.3	11.8	12.1	15.2
Tax allowance	0.0	0.9	1.2	1.2	0.7
Total	24.2	27.0	25.9	26.3	26.3
Smoothed revenue path	24.7	25.3	26.0	26.7	27.3
X factor tariff revenue(%)	0.0	0.0	0.0	0.0	0.0

Source: Table 8.2 is based on information from Part A of the draft decision.

8.5 Conclusion

The AER does not propose to approve the total revenue for each regulatory year of the access arrangement period proposed by NT Gas as these do not comply with r. 76 of the NGR.

8.6 Required amendment

Before the access arrangement proposal can be accepted, NT Gas must make the following amendment:

Amendment 8.1: amend the access arrangement information to delete Table 12.1 and replace it with the following:

Table 8.3: Forecast total revenue requirements for the access arrangement ($m, 2010–11, unless otherwise stated

	2011–12	2012–13	2013–14	2014–15	2015–16
Return on capital	9.4	9.9	9.8	9.7	9.5
Regulatory depreciation	3.5	2.9	3.1	3.3	0.9
Operating expenditure	11.3	13.3	11.8	12.1	15.2
Tax allowance	0.0	0.9	1.2	1.2	0.7
Total	24.2	27.0	25.9	26.3	26.3
Smoothed revenue path	24.7	25.3	26.0	26.7	27.3
X factor tariff revenue(%)	0.0	0.0	0.0	0.0	0.0

Part B – Tariffs

9 Demand forecasts

Demand forecasts are used to calculate the reference tariffs and to influence forecast capital and operating expenditure linked to network growth.

The AER considers that NT Gas's general approach to demand forecasting is reasonable. NT Gas has prepared its own demand forecasts based on historical data and key drivers of future demand at each delivery point. The AER accepts that there are few prospects of pipeline users other than the existing user, Power and Water Corporation (PWC). Consequently, demand from PWC is assumed to constitute the only demand for pipeline services.

The AER considers it is reasonable that growth in total gas demand forecast over the access arrangement period will rise by 2.3 per cent a year on average compared to 3.2 per cent a year in the earlier arrangement period. This lower rate of demand growth is in part due to improved technical efficiency of electricity generation. In addition, economic and population growth are forecast to be lower than in the earlier access arrangement period.

Overall, the AER considers that demand forecasts for the AGP are reasonable.

9.1 Introduction

This chapter sets out the AER's consideration of the gas demand forecasts submitted by NT Gas to apply over the access arrangement period.

9.2 Regulatory requirements

Rules 72(1)(a)(iii)(A) and 72(1)(d) of the NGR provide that the access arrangement information for a full access arrangement proposal must include:

- usage of the pipeline over the earlier access arrangement period showing, for a transmission pipeline, minimum, maximum and average demand for each receipt or delivery point, and user numbers for each receipt or delivery point

- to the extent that 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.

Rule 74(1) of the NGR provides that any information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.

Rule 74(2) of the NGR provides that a forecast or estimate must be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.

9.3 NT Gas's proposal

9.3.1 User numbers

Consistent with the earlier access arrangement period, NT Gas anticipated PWC would remain the only user of AGP over the access arrangement period.[344] It is possible that from time to time, other users may seek access to the pipeline. However, NT Gas did not consider these additional users could be forecast with certainty. Consequently, the gas demand forecasts proposed by NT Gas only include gas demand by PWC.[345]

9.3.2 Demand forecast methodology

In its access arrangement proposal and supporting information, NT Gas has set out how it has prepared its total gas demand forecasts over the access arrangement period.[346] NT Gas also set out its forecasts of expected pipeline capacity and utilisation, as required by the NGR.[347]

9.3.3 Demand forecasts

9.3.3.1 Total gas demand

NT Gas has forecast total gas demand to grow at an average of 2.3 per cent per annum over the access arrangement period compared 3.2 per cent over the earlier access arrangement period.[348] Figure 9.1 illustrates the AGP demand profile in the earlier access arrangement period and the access arrangement period.

344 NT Gas, *Access arrangement submission*, December 2010, p. 57.

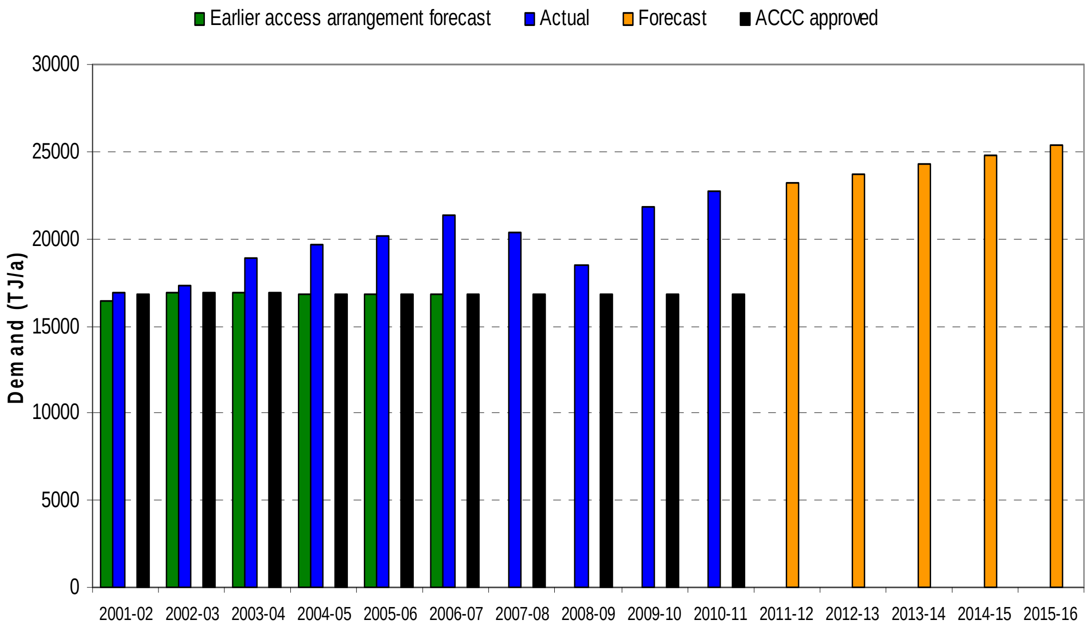
345 NT Gas, *Access arrangement submission*, December 2010, p. 57.

346 NT Gas, *Access arrangement submission*, December 2010, p. 45.

347 NT Gas, *Access arrangement submission*, December 2010, p. 59; NGR, r. 72(1)(d).

348 NT Gas, *Access arrangement submission*, December 2010, pp. 42, 48.

Figure 9.1: Total demand (TJ per annum)



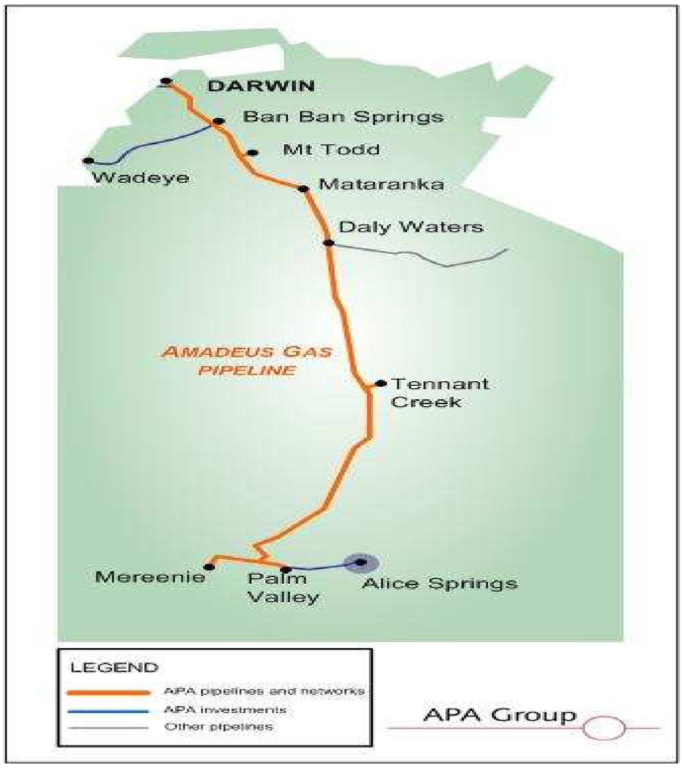
Source: NT Gas, *Access arrangement submission*, December 2010, pp. 42,48; NT Gas, *Access arrangement information for the Amadeus Basin to Darwin Pipeline*, February 2003, p. 26; NT Gas, *Access arrangement information*, June 1999, p. 41; NT Gas, *Access arrangement information*, February 1999, p. 26.

Note: Approved forecast is presented in the ACCC approved access arrangement information for NT Gas. The data was only provided for 2003–07. An average of the data available was allocated for the unknown years, 2001–02 and 2008–11.

Earlier access arrangement period

During 2006–07 to 2009–10 there was a significant drop in throughput due to the depletion of gas reserves in the Amadeus Basin. Demand increased again from 2009–10 with the connection of the new gas supply from the offshore Blacktip gas field in the Bonaparte Basin. The onshore connection of this gas field is with the Bonaparte Gas Pipeline (BGP) at Wadeye (see figure 9.2 below).

Figure 9.2: Map of northern territory pipeline network



Source: APA viewed 20 January 2011, http://www.apa.com.au/media/150046/nt.jpg.

Access arrangement period

Slower growth in demand is forecast for the access arrangement period (2.3 per cent per annum) when compared to the earlier access arrangement period.[349] Factors influencing demand include the following:

- improved efficiency of recently installed PWC electricity generating units
- commercial incentives for PWC to improve efficiency in the utilisation of its installed generation units, largely by prioritising the use of the most efficient generating units
- slowing population growth throughout Northern Territory, as well as an easing in economic growth[350]

9.3.3.2 Demand by delivery point

NT Gas has submitted that out of the 13 delivery points[351] along the AGP, the highest amount of gas is delivered to the Alice Springs, Channel Island[352] and Weddell

349 NT Gas, *Access arrangement information*, December 2010, pp. 15–16, NT Gas, *Access arrangement submission*, December 2010, pp. 40–42.

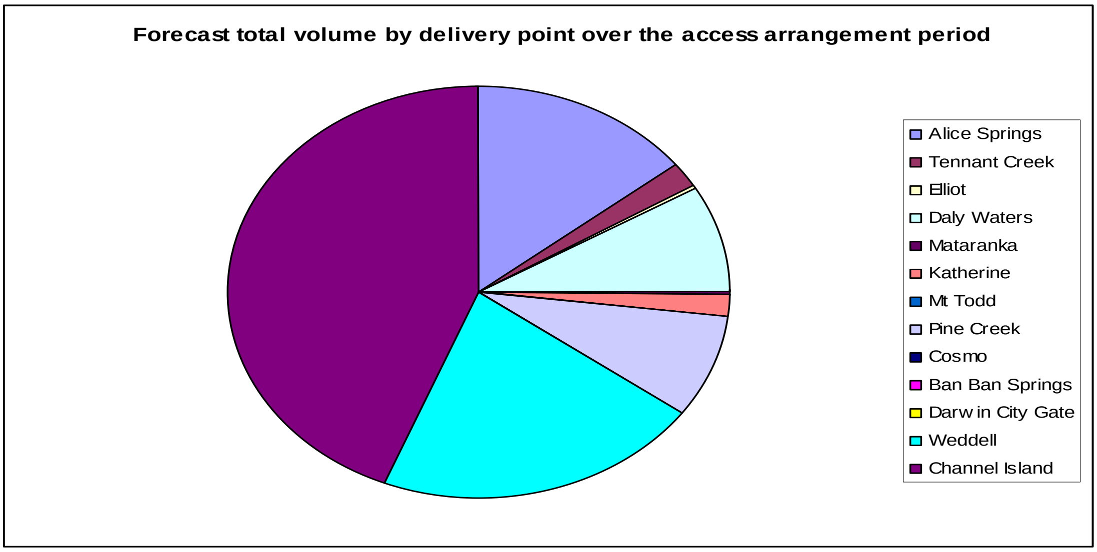
350 NT Gas, *Access arrangement submission*, December 2010, pp. 45–46.

351 The delivery points include Alice Springs, Tennant Creek, Elliott, Daly Waters, Matarnaka, Katherine, Mt. Todd, Pine Creek, Cosmos, Ban Ban Springs, Darwin City Gate, Weddell, and Channel Island.

352 Channel Island provides gas for electricity generation in Darwin.

delivery points for the generation of electricity.[353] Figure 9.3 illustrates the forecast total volume attributed to each delivery point over the access arrangement period.

Figure 9.3 Forecast total volume by delivery points over the access arrangement period (TJ)



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 42, 48.

9.3.3.3 Capacity utilisation

NT Gas has calculated forecast capacity on the same basis of historic capacity over the earlier access arrangement period.[354] NT Gas has further proposed that pipeline capacity has increased with the connection of the BGP. NT Gas proposed that utilisation of capacity over the access arrangement period is expected to grow from 79 per cent in 2010–11 to 86 per cent in 2015–16.[355] Further, NT Gas anticipated that full capacity of the pipeline is expected to be contracted to PWC, the current single user of the pipeline.[356] Table 9.1 sets out the forecast pipeline capacity and utilisation over the access arrangement period.

Table 9.1 Forecast pipeline capacity and utilisation (units as stated)

	Units	2011–12	2012–13	2013–14	2014–15	2015–16
Pipeline capacity	TJ per day	104.0	104.0	104.0	104.0	104.0
Expected utilisation of pipeline capacity	%	79	80	82	84	86

Source: NT Gas, *Access arrangement submission*, December 2010, p. 59.

353 NT Gas, *Access arrangement submission*, December 2010, pp. 49, 54.

354 NT Gas, *Access arrangement submission*, December 2010, p. 58.

355 NT Gas, *Access arrangement submission*, December 2010, p. 59.

356 NT Gas, *Access arrangement submission*, December 2010, p. 58.

9.4 Submissions

Submissions on the demand forecasts were received from Northern Territory Major Energy Users (NTMEU) and Santos Limited and Magellan Petroleum Australia Limited (Santos and Magellan).

NTMEU has submitted that:

- the capacity of AGP has increased since its connection to the BGP, providing a significant amount of spare capacity for potential users other than PWC[357]
- the forecast of gas demand growth based on the underlying growth trends exhibited in the access arrangement period appear to be consistent, but may understate the real growth now that there is spare capacity in the transmission system[358]
- the AER should ensure that NT Gas does not over-recover its allowed revenue by not allowing the full amount of gas that could be transported, particularly as there is now significant spare capacity available.[359]

Santos and Magellan have jointly submitted that:

- NT Gas has only proposed forecasts for throughput demand. Further, Santos and Magellan have submitted that NT Gas has not submitted information on actual contracted capacity and capacity of the pipeline to provide interruptible services. Santos and Magellan have submitted that this information is necessary because:
    - the reference service is a service contracted for as a quantity of contracted capacity, and a forecast of contracted capacity provides users and prospective users of the AGP with important information on the availability for capacity for provision of the reference service[360]
    - the reference tariff for the reference service is calculated on the basis of total revenue and the forecast of contracted capacity; hence scrutiny of the forecast of contracted capacity is necessary for an assessment of the reference tariff.[361]

9.5 Consultant review

The AER engaged ACIL Tasman Pty Ltd (ACIL Tasman), demand forecasting consultants, to provide an independent assessment on the reasonableness of NT Gas's proposed demand forecasts.[362] ACIL Tasman's assessment included:

357 NTMEU, *Submission to the AER*, February, 2011, p. 47.

358 NTMEU, *Submission to the AER*, February, 2011, p. 48.

359 NTMEU, *Submission to the AER*, February, 2011, pp. 48-49.

360 Santos and Magellan, *Submission to the AER*, February, 2011, p. 12.

361 Santos and Magellan, *Submission to the AER*, February, 2011, p. 12.

362 ACIL Tasman, *Review of demand forecasts for Amadeus Gas Pipeline for the access arrangement period commencing 1 July 2011*, March 2010, (ACIL Tasman, *Report – AGP*, March 2010.)

- a comparison of actual demand to forecasts in the earlier access arrangement period

- a comparison of forecasts with historic trends

- an assessment of NT Gas's input assumptions and key driver variable forecasts

- a review of NT Gas's methodologies for forecasting pipeline capacity and utilisation.

ACIL Tasman noted the following:[363]

- The bottom-up forecasts of gas demand from the delivery point level used by NT Gas were sound. Further, appropriate consideration was given to demand drivers and their influence on whether future demand will differ from historical trends.[364]

- The forecasts of average and maximum demand by delivery point are based on sound methodology and assumptions.[365]

- It is reasonable for NT Gas to not forecast any new users for the access arrangement period. Given the pipeline's current contracted capacity and its history, there is no basis for forecasting material new users for the access arrangement period.[366]

- The methodology used by NT Gas to forecast the capacity utilisation of the pipeline over the access arrangement period is reasonable.[367]

The demand growth of 2.3 per cent per annum appears to be relatively strong and is accepted as reasonable.[368] This aggregate is based on forecasts of demand at a delivery point level. Based on its analysis, ACIL Tasman considers that NT Gas's demand forecasts for the AGP to be considered reasonable.[369]

9.6 AER's consideration

9.6.1 Introduction

The AER considers the forecast methodology adopted by NT Gas in preparing its demand forecasts is reasonable. The AER also accepts that NT Gas's demand forecasts and forecasts for capacity utilisation are reasonable. Consequently, the AER considers that NT Gas's demand forecasts are arrived at on a reasonable basis and represent the best forecast possible in the circumstances.[370] Figure 9.4 illustrates demand from the commencement of the earlier access arrangement period through to

363 ACIL Tasman, *Report – AGP*, April 2010, p. 13.

364 ACIL Tasman, *Report – AGP*, April 2010, p. 13.

365 ACIL Tasman, *Report – AGP*, April 2010, p. 12.

366 ACIL Tasman, *Report – AGP*, April 2010, pp. 16–17.

367 ACIL Tasman, *Report – AGP*, April 2010, p. 17.

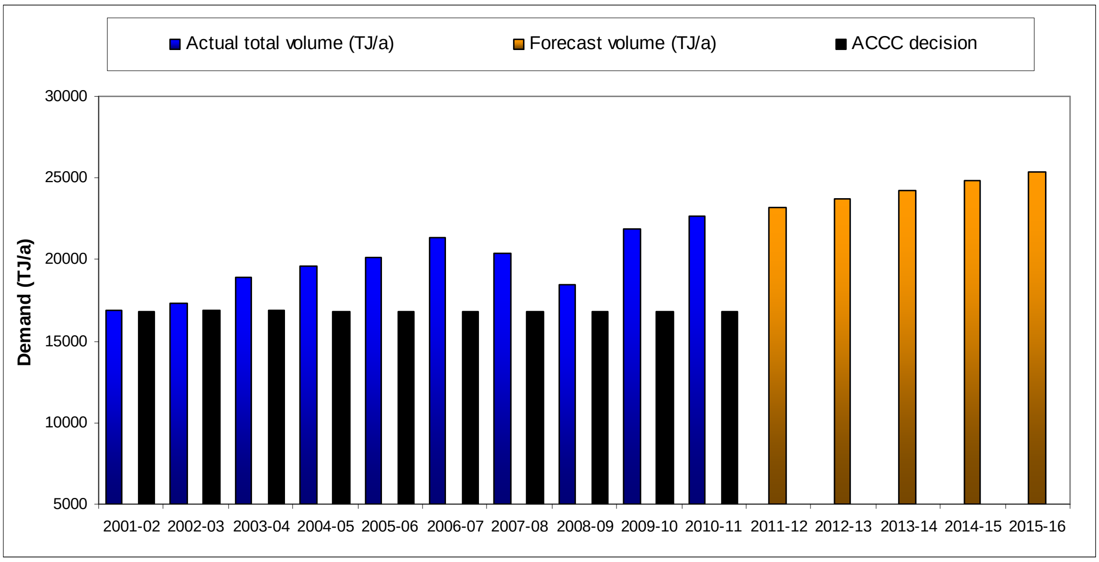
368 ACIL Tasman, *Report – AGP*, April 2010, p. 18.

369 ACIL Tasman, *Report – AGP*, April 2010, p. 18.

370 NGR, r. 74(2).

2015–16. In the earlier access arrangement period demand was greater than had been expected in some areas of the NT. In particular, gas usage increased considerably in Alice Springs; from total usage of 738.2 terajoules (TJ) in 2001–02 to 3381.8 TJ in 2009–10.[371] Further, gas delivery to Channel Island was also above trend for the years 2005–06 to 2007–08.[372] The decreases in 2007–08 and 2008–09 were in part due to dwindling gas supply from the Amadeus Basin. In 2009–10, gas sourced from Blacktip gas field was able to meet higher levels of demand.[373]

Figure 9.4: Total demand (TJ per annum)



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 42, 48.

In respect of the earlier access arrangement period, r. 72(1)(a)(iii)(A) of the NGR requires a service provider to show minimum, maximum, and average demand for each receipt or delivery point. Further, r. 72(1)(d) of the NGR requires a forecast of pipeline capacity and utilisation, to the extent it is practicable, over the access arrangement period. The AER accepts all these aspects of NT Gas's proposal.

9.6.2 Forecast methodology and assumptions

The AER considers the demand forecast methodology and assumptions adopted by NT Gas is reasonable for the following reasons:

- average demand for each delivery point is based on an analysis of historic trends in gas volumes and key drivers for gas demand for each delivery point
- maximum demand for each delivery point depends on the nature of demand at each delivery point:

371 NT Gas, *Access arrangement submission*, December 2010, p. 40. The increase in demand in Alice Springs reflects the steady increase in the demand for electricity generation.

372 NT Gas, *Access arrangement submission*, December 2010, p. 42.

373 NT Gas, *Access arrangement submission*, December 2010, p. 33.

  - Tenant Creek, Pine Creek and Elliot – daily demand is in line with the gas requirements to fuel the maximum output of generators installed at these sites
  - Daly Waters (Macarthur River mine), Mataranka and Darwin City Gate – based on historical values without forecast growth
  - Katherine and Alice Springs – maximum daily quantities are derived based on information provided by PWC
  - Weddell –having commenced in 2008, there is limited historical information. Maximum demand is forecast to increase by 3 per cent per annum having reached full delivery capacity in 2010–11
  - Channel Island – maximum demand is forecast by averaging the highest five maximum values observed in the earlier access arrangement period. Channel Island's maximum demand is also forecast to grow at approximately 3 per cent per annum from 2010–11 after declining in 2008–09 due to gas supply constraints.
- the bottom-up consideration of gas demand at a delivery point level used by NT Gas to develop its demand forecasts is sound as appropriate consideration has been given to demand drivers, and to factors that may cause future demand growth rates at particular delivery points to differ from historical trends.[374]

In support of the AER's position, ACIL Tasman considered that in the circumstances, the methodology and assumptions used by NT Gas to develop the demand forecasts is sound, and no other viable approach would be likely to yield better or more reliable results.[375]

The AER considers that the basis of NT Gas's methodology and assumptions is reasonable and therefore meets the requirements of r. 74(1) and r. 74(2)(a)of the NGR.

9.6.3 User numbers

The AER considers it is reasonable for NT Gas to forecast user numbers based on the historical pattern of user numbers, the limited scope for additional firm contracting arrangements and the prospect of finding additional users. Table 9.2 shows the historical and forecast user numbers by delivery point.

374 ACIL Tasman, *Report – AGP*, April 2010, p. 13.

375 ACIL Tasman, *Report – AGP*, April 2010, p. 12.

Table 9.2 NT Gas historical and forecast user numbers for delivery points

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
Alice Springs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Tennant Creek	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1
Elliott	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Daly Waters	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mataranka	1	1	1	1	1	2	2	1	1	1	1	1	1	1	1
Katherine	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1
Mt Todd	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0
Pine Creek	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cosmo	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Ban Ban Springs	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0
Darwin City Gate	1	1	1	1	1	2	2	2	1	1	1	1	1	1	1
Weddell	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
Channel Island	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1

Source: NT Gas, *Access arrangement submissio*n, December 2010, pp. 43, 57–58.

The AER accepts that, in all likelihood, PWC will remain the sole user for the pipeline and that the capacity of the pipeline will be fully contracted to PWC. ACIL Tasman also considered that given NT Gas's current contracted capacity and its history, there is no basis for forecasting material new users for the access arrangement period.[376] Further, NTMEU submits that with the increased capacity in the AGP, there is now capacity for other users than PWC.[377] The AER acknowledges that historically, users other than PWC have only contracted for short periods. The AER considers that despite NT Gas currently marketing[378] transportation services on the pipeline, it is unlikely there will be any other significant users demanding large quantities of gas apart from PWC over the access arrangement period.

376 ACIL Tasman, *Report – AGP*, April 2010, pp. 16–17.

377 NTMEU, *Submission to the AER*, February, 2011, p. 47.

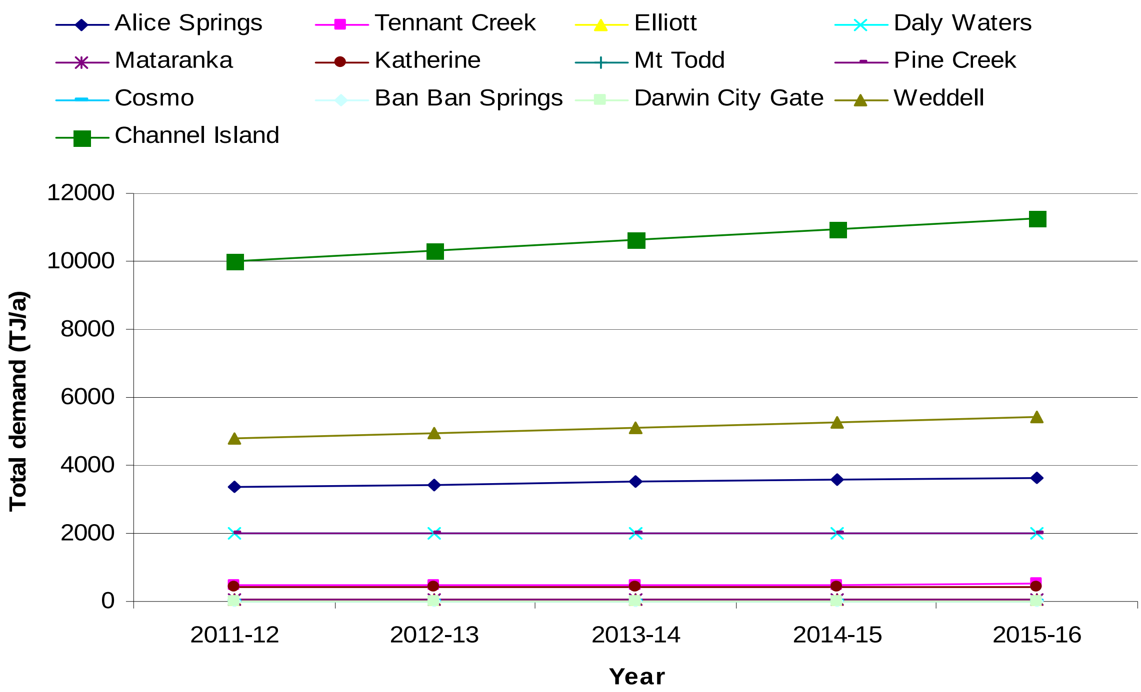
378 The AER's views on marketing are discussed in chapter 7 of the draft decision.

9.6.4 Demand forecasts

9.6.4.1 Total demand

The AER considers that in arriving at a total gas demand forecast, it is appropriate to consider the likely demand at each of the delivery points along the AGP and compare these demands with the cumulative historical demand. NT Gas's forecast total demand has been derived from demand forecasts at each delivery point which takes into account the characteristics that drive demand at each delivery point.[379] Figure 9.5 illustrates the total gas demand for each delivery point over the access arrangement period. From the figure, it can be seen that the delivery point at Channel Island receives the largest volume of throughput.

Figure 9.5 Total gas demand for each delivery point over the access arrangement period (TJ)



Source: NT Gas, *Access arrangement submission*, December 2010, pp. 47–48.

A key aspect of NT Gas's demand forecasts is that it expected growth in total usage to be lower in the access arrangement period (2.3 per cent a year) than it had been over the earlier access arrangement period (3.2 per cent a year). The AER has examined NT Gas's proposal and agrees that gas usage for the access arrangement period is reasonable for the following reasons:

- improved efficiency of PWC electricity generating units[380]
- drivers for PWC to improve efficiency in the utilisation of its installed generation units, largely by prioritising the use of the most efficient generating units[381]

379 NT Gas, *Access arrangement submission*, December 2010, p. 45.

380 NT Gas, *Access arrangement submission*, December 2010, p. 45.

- slower population and economic growth of the NT. Table 9.3 sets out data and forecasts from the NT government. Table 9.3 shows gross state product (GSP) and population growth for NT from 2000–16. The average GSP growth in the earlier access arrangement period was 3.6 per cent per annum compared to 3.9 per cent per annum GSP growth over the access arrangement period.[382] Further average population growth in the earlier access arrangement period was 1.6 per cent per annum compared to 2.0 per cent per annum. Further, ACIL Tasman has considered that given that NT has a relatively small and open economy, it is influenced by international trade and as a result tends to be volatile from year to year.[383] The AER considers these projected growth rates support the demand forecast proposed by NT Gas.

Figure 9.3 NT GSP and population growth over the earlier and access arrangement period (%)

	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
NT GSP	5.4	1.8	0.5	2.3	5.5	6.7	6.7	3.9	2.6	0.4	2.8	4.1	4.3	4.0	4.1
NT population	1.0	1.1	0.5	0.6	1.6	2.3	1.9	2.4	2.2	2.1	2.5	1.9	2.0	1.9	1.8

Source: NT Government, viewed 31 March 2011, www.budget.nt.gov.au/budget2.html, NT Government, viewed 31 March 2011, www.budget.nt.gov.au/budget3.html.

- ACIL Tasman considered that the factors identified by NT Gas are likely to lead to future gas demand growth rates being lower than historical rates of demand growth.[384] Further, ACIL Tasman considered that compared to growth rates in other jurisdictions, the future gas demand growth rate of 2.3 per cent is relatively strong.[385] In addition given the future growth rate has not been directly estimated but arises implicitly from the detailed examination of gas demand drivers at a delivery point level, ACIL Tasman considered the implied demand growth rates over the access arrangement period are reasonable.[386]

On the basis of the advice from ACIL Tasman and its own analysis, the AER considers that the total gas demand forecasts have been arrived at on a reasonable basis and represent the best forecasts possible in the circumstances. The AER considers that NT Gas's total demand forecasts meet the requirements of r. 74(2) of the NGR. Table 9.4 summarises the key drivers at each delivery point.

381 NT Gas, *Access arrangement submission*, December 2010, p. 45.

382 Note; the earlier access arrangement period was a ten year period compared to the access arrangement period which is over five years.

383 ACIL Tasman, *Report – AGP*, April 2010, p. 15.

384 ACIL Tasman, *Report – AGP*, April 2010, p. 15.

385 ACIL Tasman, *Report – AGP*, April 2010, p. 15.

386 ACIL Tasman, *Report – AGP*, April 2010, p. 15.

Table 9.4 Total gas demand drivers for each delivery point

Delivery point	Drivers
Alice Springs	historical growth trend, boosted by increasing penetration of reverse cycle air conditioners, but offset to some extent by more efficient generator units installed by PWC. Overall 2 per cent per annum growth in demand and peak requirements
Tennant Creek	similar demand drivers to Alice Springs. Overall 1.7 per cent per annum growth in demand and peak requirements based on historical trends
Elliott	stable demand based on current generation capacity continuing to operate at full capacity
Daly Waters	stable demand based on historic flat average demand for Macarthur River Mine, and stable mine production outlook
Mataranka	stable demand in line with 2010–11 levels, higher than in recent years where gas supply was constrained and substitute fuel used. Availability of Blacktip gas field has removed gas supply constraints and allows full demand of the main industrial customer to be met with gas
Pine Creek	steady base load delivered by a third party generator under contract to PWC. Gas demand therefore does not change significantly over the access arrangement period
Katherine	peaking electricity load. Demand growth at 1 per cent per annum in line with historical growth
Weddell	delivery point commissioned in 2007. The forecast reflects increased utilisation of these more efficient units and the displacement of gas load from Channel Island. Forecast growth of 3 per cent per annum reflecting the trend in total gas demand growth for the Darwin/Katherine transmission system over the current access arrangement period
Channel Island	dominant load for with 43 per cent of 2010–11 volumes for the pipeline. Some shift of gas demand at this delivery point to more efficient generation units at Weddell. However PWC is currently expanding Channel Island generation capacity with efficient modern units, so forecast growth of 3 per cent per annum reflecting the trend in total gas demand growth for the Darwin/Katherine transmission system over the current access arrangement period, capped at 60 TJ per day reflecting electricity transmission constraints. Overall Darwin/Katherine transmission system gas demand (Pine Creek, Katherine, Weddell, and Channel Island) forecast to grow by 2.6 per cent per annum. This is a slight decrease from the growth rate in the earlier access arrangement period of 3.2 per cent per annum, reflecting increased efficiency of newer generating units installed at Channel Island, Katherine and Weddell.
Mt Todd	Mt Todd mine closed 2006–07; no gas deliveries since that time and no deliveries forecast
Cosmo-Howley	lateral decommissioned 2008, no deliveries forecast
Ban Ban Springs	delivery point for Bonaparte Pipeline commissioning gas in 2000–09 and 2009–10 but now a supply point, no deliveries forecast
Darwin City Gate	supplies to commercial and light industrial users; low demand not material to overall forecast (0.4 per cent of 2010–11 demand total) forecast to remain steady

Source: NT Gas, *Access arrangement submissio*n, December 2010, p. 59, ACIL Tasman, *Report – AGP*, April 2010, pp. 12–13.

9.6.5 Minimum, maximum and average demand

Rule 72(1)(a)(iii)(A) of the NGR requires that the access arrangement information for a transmission pipeline must include minimum, maximum and average demand for the earlier access arrangement. NT Gas provided information on minimum, maximum and average demand over the earlier access arrangement period as set out in table 9.5.

The information reflects the cumulative demand at the lowest, highest and average volumes at the delivery points along the AGP over the earlier access arrangement period. The AER considers the minimum, maximum and average demand for each delivery point provided by NT Gas meets the requirement of r. 72(1)(a)(iii)(A) of the NGR.

Table 9.5 Minimum, maximum and average demand 2001–11 (TJ per day)

	Minimum demand	Maximum demand	Average demand
2001–02	23.9	83.4	46.4
2002–03	22.4	80.5	49.2
2003–04	18.2	94.2	51.6
2004–05	23.5	87.6	53.8
2005–06	24.9	85.8	55.8
2006–07	26	91.2	58.5
2007–08	22.2	94.2	55.7
2008–09	7.6	103.4	50.4
2009–10	6.4	105.8	59.9
2010–11	15	114.4	61.9

Source: NT Gas, *Access arrangement submission*, December 2010, pp. 40–42.
Note: Values in table 9.5 are derived from the summation of demand at each delivery point over the earlier access arrangement period.

9.6.6 Forecast pipeline capacity and utilisation

Rule 72(1)(d) of the NGR requires that, to the extent practicable, the access arrangement information should include forecast pipeline capacity and utilisation of pipeline capacity over the access arrangement period. The AER accepts NT Gas's forecast capacity has been calculated on the same basis as historic capacity.[387] The AER also accepts NT Gas's forecast utilisation of the pipeline has been derived using an estimate of the non-coincident maximum demand for all delivery points divided by the forecast capacity of the pipeline.[388] The AER considers its position is supported by ACIL Tasman who considered the method used by NT Gas to estimate capacity utilisation over the access arrangement period is appropriate and could be expected to yield a reasonable forecast of capacity utilisation.[389]

387 NT Gas, *Access arrangement submission*, December 2010, p. 58.

388 NT Gas, *Access arrangement submission*, December 2010, p. 58.

389 ACIL Tasman, *Report – AGP*, April 2010, p. 17.

The AER considers that pipeline capacity and utilisation are arrived at on a reasonable basis and meet the requirements of r. 74(2) of the NGR.

9.6.6.1 Spare capacity

The AER sought further information from NT Gas on the capacity of the pipeline over the access arrangement period. In particular, the AER sought information on the following:

- firm capacity
- interruptible capacity
- spare capacity to provide firm and interruptible services including when the spare capacity will become available.

NT Gas updated its and APA Group's website [390] with information on expected pipeline capacity and utilisation. NT Gas provided information as shown in table 9.6 on its website.

Table 9.6: Expected pipeline capacity and utilisation

	Units	2011–12	2012–13	2013–14	2014–15	2015–16
Pipeline capacity	TJ per day	104.0	104.0	104.0	104.0	104.0
Utilisation of pipeline capacity	%	79	80	82	84	86

Source: APA, http://www.apa.com.au/media/184216/agp%20capacity%20-%202011.pdf, Viewed 2 March 2011, NT Gas, http://www.ntgas.com.au/our-company.html, viewed 2 March 2011.

NT Gas indicated the AER that the AGP capacity has been calculated based on current injection and load characteristics, and as the expected pipeline utilisation is below 100 per cent, there may be potential to offer pipeline services to other users.[391]

The AER considers that the information provided by NT Gas supports its proposal.

9.7 Conclusion

The AER approves NT Gas's proposed demand forecasts as they meet the requirements of r. 72(1)(a)(iii), r. 72(1)(d), and r. 74 of the NGR.

390 Email NT Gas to AER, *AER.NTGas.02-Questions on pipeline capacity*, 7 February 2011, NT Gas, http://www.ntgas.com.au/our-company.html, viewed 2 March 2011, viewed 2 March 2011

391 Email NT Gas to AER, *AER.NTGas.02-Questions on pipeline capacity*, 7 February 2011. On the website, NT Gas also makes note of the services it offers, which includes firm services, interruptible services and negotiates services. Further, NT Gas has included contact details for how potential users on the availability of services.

10 Tariffs–transmission pipelines

An access arrangement is required to set out how a service provider intends to charge for reference services. The NGR requires that the basis for setting reference tariffs be explained. This is achieved by defining the tariff classes and comparing the revenue to be raised by each reference tariff with the cost of providing each individual reference service.

NT Gas has proposed a single reference tariff instead of the zonal tariff structure that was in place in the earlier access arrangement. The zonal tariffs in the earlier access arrangement period have been discarded due to a change in the direction gas flows along the pipeline and the potential for gas to flow in either direction. The AER considers the proposed reference tariff, which is a flat 'postage stamp' capacity charge, balances the need for efficient prices and to maximise pipeline utilisation.

The AER considers that most elements of NT Gas's proposed tariffs, including the simplified 'postage stamp' tariff, are compliant with the NGR. In revising its reference tariffs to address matters in this chapter, NT Gas is required to incorporate the various amendments required by the AER in other chapters of the draft decision. The AER requires that the reference tariff for 2011–12 be set at $0.5778 per gigajoules (GJ) of delivery point maximum daily quantity (MDQ).

10.1 Introduction

This chapter sets out the AER's consideration of NT Gas's tariff structure and allocation of revenue. Specifically, the AER has assessed the proposal for its compliance with the NGR. NT Gas has addressed the key aspects of its proposed tariff structure, including:

- the number of tariff classes, tariffs, and charging parameters
- the share of total revenue to be recovered from each tariff class
- the cost-reflectivity of tariffs and charging parameters.

10.2 Regulatory requirements

With respect to reference tariffs, the NGR requires NT Gas to:

- describe the proposed approach to the setting of tariffs, including the method used to allocate costs, and demonstrate the relationship between tariffs and costs and provide a description of any applicable pricing principles (r. 72(1)(j))
- demonstrate that total revenue is allocated between reference and other services in the same ratio that costs are allocated between these services (r. 93(1)&(2))
- for each reference tariff, show how it would recover the portion of revenue attributable to that reference service and, to the extent practicable, attributable to users or user classes (r. 95(1))
- allocate directly attributable costs to users or user classes to which they are referable (r. 95(3)(a))

- allocate indirect costs between users or user classes in a manner consistent with the revenue and pricing principles (r. 95(3)(b))
- specify the tariffs for each reference service (r. 48(1)(d)(i) & (ii)).

The AER has limited discretion in assessing compliance with r. 95.[392]

10.3 Access arrangement proposal

The key features of NT Gas's proposed reference tariff structure and cost allocation methodology are as follows:

- a single reference service (the "Firm service")[393]
- all pipeline revenues to be recovered from the reference service, on the basis that users and prospective users are expected to utilise this service only[394]
- a single user class[395]
- a single reference tariff for pipeline access, irrespective of the injection or delivery point along the pipeline[396]
- a charging parameter based on capacity, that is, MDQ[397]
- the 2011–12 reference tariff is set at $0.7596 per GJ of delivery point MDQ.[398]

10.4 Submissions

The AER received four submissions that addressed the tariffs. These submissions were from the Power and Water Corporation (PWC), the Northern Territory Major Energy Users (NTMEU), a combined submission from Santos Limited and Magellan Petroleum Australia Limited (Santos and Magellan), and the Northern Territory Treasury (NT Treasury).

PWC has submitted that:

- NT Gas has inappropriately calculated the reference tariff based on total delivery point capacity per day (117 terajoules (TJ) per day, which can vary up to 127.4 TJ per day). The reference tariff should be calculated according to the aggregate quantity of gas to be delivered across all delivery points on a day, estimated to be 110 TJ per day

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392 NGR r. 40(2). Under r. 40(2), limited discretion means the AER may not withhold its approval to an element of an access arrangement proposal that is governed by the relevant provision if the AER is satisfied that it complies with applicable requirements of the NGL, and is consistent with applicable criteria (if any) prescribed by the NGL.

393 NT Gas, *Access arrangement proposal*, December 2010, p. 5.

394 NT Gas, *Access arrangement submission*, December 2010, p. 146.

395 NT Gas, *Access arrangement submission*, December 2010, p. 147.

396 NT Gas, *Access arrangement submission*, December 2010, p. 146.

397 NT Gas, *Access arrangement information*, December 2010, p. 29.

398 NT Gas, *Access arrangement proposal*, December 2010, p. 21.

- the overrun, imbalance and daily variance charges have no basis where pipeline revenues are fully allocated to the reference services, assuming full capacity utilisation on the pipeline.[399]

The NTMEU has submitted that:

- due to the variability of flows on a bi-directional pipeline, NT Gas has the flexibility to 'over-recover' significant revenues from a highly depreciated asset

- the AER should closely examine the existing contract with PWC to ensure NT Gas does not recover excessive revenues

- it is likely there will be demand for bi-directional transport on the pipeline, and the AER should set reference services as they are likely to be used as the basis for negotiation.[400]

Santos and Magellan has submitted that:

- the cost allocation methodology and postage stamp tariff proposed by NT Gas are consistent with the revenue and pricing principles and the national gas objective

- with gas sources and delivery points at various locations along the AGP and with no significant variable costs of gas transmission, there is no economic rationale for a distance based reference tariff

- there is no basis for economic efficiency in a gas throughput tariff component given that costs are largely fixed in nature and not dependant on throughput.[401]

NT Treasury has submitted that:

- tariffs proposed in the access arrangement should reflect economically efficient principles

- the economic efficiencies of a tariff structure should be balanced against ensuring the service provider can recover revenues to encourage future investment and the safe and reliable operation of the asset.[402]

10.5 AER's considerations

The AER has reviewed NT Gas's proposed reference tariff structure, and considers it best meets the requirements of the NGR and NGL. The AER has come to this view for two main reasons. First, the nature of gas flows on the pipeline have changed significantly from the earlier access arrangement–when the zonal tariffs were approved–as gas is no longer expected to flow from the south to the north beyond 2012. Instead, injection will occur largely in the north while deliveries to the south will be limited. However, prospective users may still wish to transport gas

399 PWC, *Submission to the AER*, March 2011, pp.10–12.

400 NTMEU, *Submission to the AER*, February 2011, pp. 60–62.

401 Santos and Magellan, *Submission to the AER*, January 2011, p. 12.

402 NT Treasury, *Submission to the AER*, March 2011, p. 4.

northwards, and there is still gas available in the Amadeus Basin, at the southern end of the pipeline. Were zonal tariffs to be retained, tariffs in the south would increase significantly. A zonal tariff would likely have the effect of substantially reducing potential for higher utilisation of the pipeline. The AER therefore does not consider it is in the long term interests of users, prospective users or NT Gas to retain a zonal tariff structure.

Second, the AER accepts that a capacity based tariff is more relevant given the circumstances of the pipeline. The key constraint to pipeline access is the availability of capacity. The capacity of the pipeline is currently, and expected to continue to be fully contracted to a single user. The AER considers a capacity based charge would provide a more direct signal of pipeline usage than gas flows.

In submissions from interested parties, no concerns were raised about the proposed single reference tariff. Further, Santos and Magellan have explicitly supported the proposal. The submissions were received from a broad range of interested parties including the single existing user, a body representing prospective users, a jurisdictional government agency, and a supplier of gas to the pipeline.

The AER's reasoning for its decision is set out against the following headings:

- the allocation of revenues to the reference service
- the establishment of user classes
- the capacity based charging parameter
- the derivation of the reference tariff.

10.5.1 Allocation of revenue to the reference service

The AER accepts NT Gas's proposal to allocate total revenues entirely to the proposed reference service. While NT Gas proposed two non–reference services, no costs were allocated to these services based on an expectation by NT Gas that there would be no demand for these services. It is therefore appropriate to set tariffs such that the revenue requirement is fully recovered from the reference service. That is, the reference tariffs have been calculated based on the demand forecasts discussed in chapter 9 of the draft decision.

The NTMEU submitted that an interruptible service could be established as a reference service.[403] However, NTMEU did not estimate the likelihood of any prospective users of such a service. Similarly, the NT Treasury submitted there is scope for NT Gas to offer both firm and interruptible reference services.[404] The AER considers that in the circumstances, it would not be reasonable to anticipate demand for an interruptible service. In the absence of demand for an interruptible service, it would not be reasonable to reduce the tariffs for the proposed reference service to offset the revenues associated with an interruptible service. The AER accepts that full

403 NTMEU, *Submission to the AER*, February 2011, p. 61.

404 NT Treasury, *Submission to the AER*, March 2011, p. 4.

allocation of revenues to the single proposed reference service is consistent with r. 93(1) and r. 93(2) of the NGR.

10.5.2 Establishment of user classes and allocation of costs

In further allocating reference service costs across users, the AER is implicitly required to consume whether there are users or user classes that should make differential contributions to the cost of providing the reference service. The AER accepts NT Gas's proposal that there is a single user class on the pipeline. Under the single tariff proposed by NT Gas, all users pay the same price per unit of capacity. An alternative to this structure would require the separation of users or user classes into 'zones', as was the case in the earlier access arrangement period. The AER considers that there are no practical means to separate users and prospective users into different classes, given the potentially variable direction of gas flows on the pipeline.

The AER is then required to assess whether direct and indirect costs are allocated to users or user classes in accordance with r. 95(3) of the NGR. The direct costs of usage on the pipeline are the specific connection assets that only serve particular users, such as metering equipment. The AER does not consider there is any reason other than to expect these costs will differ significantly between users, and this will be addressed by setting a per unit tariff. Consequently, a reference tariff that spreads total pipeline costs evenly between users must necessarily allocate at least the direct costs to each user.

The remainder—and majority—of pipeline costs are therefore indirectly attributable. The AER considers that, in the circumstances, NT Gas's proposed reference tariff allocates costs in a manner consistent with the revenue and pricing principles as required by r. 95(3)(b) of the NGR. The revenue and pricing principles require the AER to consider, amongst other things, the efficient level of pipeline usage weighed against the risk of under utilisation of the pipeline.[405] The AER considers:

- the retention of zonal tariffs may lead to underutilisation of the pipeline
- a postage stamp tariff will prevent large tariff increases in the southern and central sections of the pipeline, which will limit the likelihood of underutilisation
- this greater potential utilisation of the pipeline is in the long term interests of users, prospective users and NT Gas.

Zonal tariffs in the earlier access arrangement period

In the earlier access arrangement period, the ACCC accepted three tariff zones proposed by NT Gas.[406] At that time, all gas on the pipeline was sourced from the Amadeus Basin located at the southern end of the pipeline, and transported north to delivery points along the pipeline. Depending on the distance that gas was physically transported, it was possible to differentiate users into user classes. Specifically, users

405 NGL ss. 24(3) and 24(7).

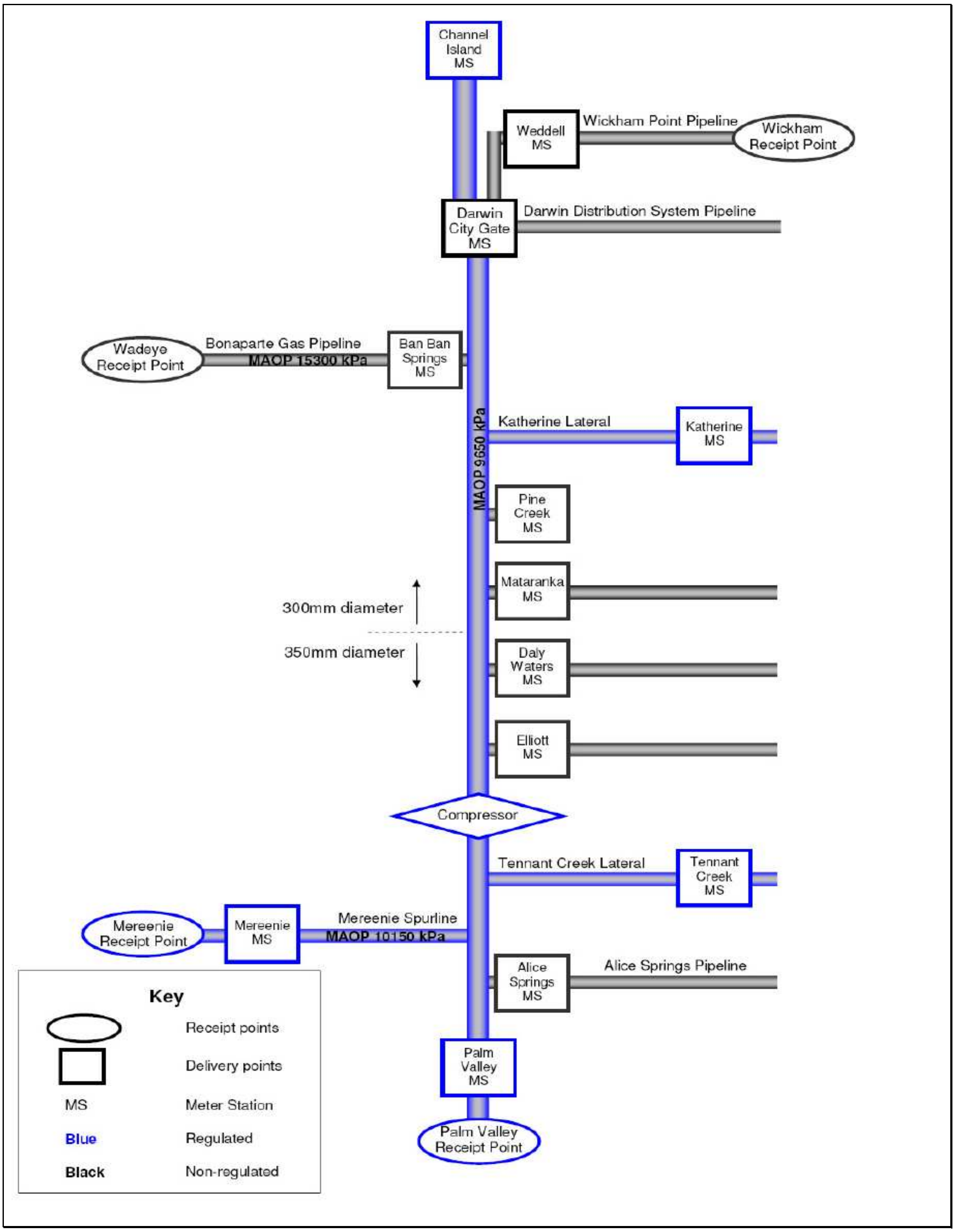
406 ACCC, *Final decision*, December 2002, p. 108.

were classified into three tariff zones based on zonal boundaries drawn at points of change in the physical characteristics of the pipeline.[407] As set out in figure 10.1:

- Zone 1—everything south of the compressor at Warrego
- Zone 2—from the compressor to the change in pipeline diameter at Mataranka
- Zone 3—everything north of the change in pipeline diameter at Mataranka.

407 These physical demarcations were: a compressor station at Warrego, and a change in pipeline diameter at Mataranka.

Figure 10.1: Schematic of Northern Territory pipeline network



Source: NT Gas, *Access arrangement submission*, December 2010, p. 3.

Proposed 'postage stamp' tariffs

For the access arrangement period, NT Gas has proposed to remove the zonal boundaries as a result of the change in direction of gas flows through the pipeline.[408]

408 NT Gas, *Amadeus gas pipeline AA revision, tariff structure and considerations*, 8 March 2011. In practice, NT Gas only expects two of the injection points (Ban Ban Springs and Mereenie) to be used during the access arrangement period.

NT Gas proposed that while gas will be sourced predominantly from the Blacktip gas field, (via the Wadeye receipt point) and partially from the Mereenie receipt point until 2012, the direction of gas flows will be variable and that the pipeline now functions more like a 'pressure vessel'.[409] For example, to even out the periodic difference between gas injections and withdrawals, gas injections may travel in a southerly direction before returning northwards. Similarly, gas injected in the south for users in the north may simply maintain pressure in the pipeline with users physically consuming gas sourced from Blacktip in the north. The direction and distance of actual gas flows are variable and therefore the previous tariff zones or the distance between the points of injection and delivery do not adequately describe the actual use of the pipeline. Further, there are still proven gas reserves in the Mereenie gas field, and while it has not been forecast, it is possible that south–north gas flows could recommence during the access arrangement period. Santos and Magellan, who own these gas fields, submitted that they are actively marketing gas for use on the pipeline, potentially until 2030.[410] Consequently, the AER accepts that the previous zones are no longer appropriate in determining user classes or tariffs.

The AER also considers the effect of retaining zonal tariffs on prospective users. NT Gas estimated some approximate tariffs that would apply if the zonal structure was retained. These are set out in table 10.1 below. The zonal tariffs were reviewed by the AER. The retention of zonal tariffs would result in a relatively small reduction to tariffs in the north (zone 3) and significant increases to the tariffs in the southern and central tariff zones (zones 1 and 2). Compared to a single zone tariff, users towards the north of the pipeline would face slightly lower per unit tariffs, while users in the central and southern zones would face significantly higher prices.

Table 10.1: Indicative zonal tariffs compared to a single tariff

	Earlier access arrangement		**NT Gas proposed access arrangement: if zonal tariffs are retained**		**NT Gas proposed access arrangement: under a postage stamp tariff**
Zone	2010–11 tariffs ($ per GJ)^	Cumulative tariff at delivery point ($ per GJ)*	2011–12 tariffs ($ per GJ)^	Cumulative tariff at delivery point ($ per GJ)*	2011–12 tariffs ($ per GJ)^
Zone 1 (south)	1.05	1.05	3.43	5.72	0.91 (single tariff, no zones apply)
Zone 2 (central)	0.74	1.79	1.84	2.29	
Zone 3 (north)	0.62	2.41	0.45	0.45	

Source: ^: NT Gas, *Presentation to the AER—Tariff structure and considerations,* 8 March 2011, slide 11 (indicative only), *: AER analysis.

409 Santos and Magellan, *Submission to the AER*, February 2011, p. 1.

410 Santos and Magellan, *Submission to the AER*, February 2011, p. 1–2.

Note: The zonal tariffs for the access arrangement period are indicative, and are calculated based on some general assumptions. These tariffs are not intended to be precise, but give a sense of price magnitudes. The AER considers that, due to the majority of gas flows coming from the north of the pipeline, the tariff would sum in reverse to the earlier access arrangement period. The AER also considers that tariffs are expressed in $ per GJ, which is a throughput measure, in contrast to NT Gas's proposed capacity tariff. This is for the purposes of comparison in terms of the magnitude of price impacts. Also, the postage stamp tariff price is converted from the proposed capacity reference tariff by assuming a load factor of 1.2 (i.e. increasing the capacity tariff by 20 per cent).

NT Gas proposed that under a zonal or distance based tariff, [c-i-c]. NT Gas proposed that the most likely prospective user of the pipeline; based on scenario analysis, would be located in the southern section of the AGP.[411] Further, in its submission, NT Treasury submitted that excessive tariffs would act as a disincentive to potential users of the AGP, which would be inefficient considering the abundance of gas supplies near the pipeline.[412]

The AER accepts that prospective users would most likely utilise the southern sections of the AGP. Opportunities for additional gas supply, not already taken up by PWC, would likely come from gas fields in the Amadeus Basin. Such prospective users could supply gas to mines along the pipeline where existing energy needs are met from diesel generators. A zonal tariff structure would therefore adversely affect further utilisation of the pipeline. Further, the AER is aware that the existing user is expected to be contracted to meet the full costs of providing the reference service. Zonal prices would result in the same revenues being recovered from the existing user, and prospective users may be discouraged by higher tariffs in the southern zones. While the demand forecasts do not include any provisions for prospective users, the interests of prospective users should be allowed for in the structure of the reference tariffs. Therefore, the AER considers a zonal tariff would not have any practical benefit in promoting the long term interests of consumers.

In light of these considerations, the AER accepts that a tariff based on a single user class encourages pipeline utilisation that is in the long term interests of users, prospective users, and the service provider. On balance, the AER considers the tariff structure proposed by NT Gas satisfies the revenue and pricing principles, and is consistent with r. 95(3) of the NGR.

10.5.3 Capacity based charging

The AER accepts NT Gas's proposed capacity tariff, based on the user's MDQ at the relevant delivery point.[413] NT Gas had previously charged on the basis of gas throughput.

The AER considers that a capacity based charge is reasonable given the capacity of the pipeline is expected to be fully contracted for the entirety of the access

411 NT Gas, *Tariff structure and considerations*, 8 March 2011, slide 10.

412 NT Treasury, *Submission to the AER*, March 2011, p. 3.

413 NT Gas, *Access arrangement information*, December 2010, p. 29.

arrangement period to PWC.[414] Capacity, rather than throughput, is expected to be the primary constraint on access to the pipeline. In their submission, Santos and Magellan noted the costs associated with the reference service were largely fixed in nature and therefore the use of capacity rather than throughout was appropriate.[415]

10.5.4 Calculation of reference tariffs

In its proposal, NT Gas derived its tariff by dividing building block revenue by the sum of forecast MDQ at all of the existing delivery points. PWC submitted that this was an inappropriate method for calculation of the capacity charge, and indicated that the appropriate value was the structural limit of the pipeline's capacity to meet the MDQ.[416] In particular, PWC was concerned that the method of calculating the capacity base charge would result in over charging because of growth in forecast delivery point demand over the access arrangement period. The AER considers that PWC may have understood that the 2011–12 delivery point MDQ would be used to calculate tariffs for each year in the period. This is not the case, and forecast delivery point MDQ for each distinct year is used in that year to determine the reference tariff.

In contrast, the proposed access arrangement requires that users nominate delivery point maximum capacities for specific days to NT Gas on an ongoing basis. NT Gas would then determine if the allocation was structurally possible. As such, the reference tariff is charged on the basis of daily delivery point capacity reservation, rather than the physical maximum capacity on the pipeline. Unit tariffs each year would reflect the forecast growth in annual delivery point capacity, which is based on the expected growth in total nominated delivery point MDQ. This approach would limit the risk of over or under recovery, as raised by PWC, to the extent that delivery point MDQ forecasting is accurate. Consequently, the AER considers it is consistent and appropriate to use the forecast MDQ values at delivery points to determine a per unit price.

The AER accepts NT Gas's proposed approach to deriving tariffs. By incorporating the changes required to building block components elsewhere in the draft decision, the reference tariff for 2011–12 should be amended to $0.5778 per GJ of delivery point MDQ as required by amendment 10.1.

10.6 Conclusion

The AER accepts the following aspects of NT Gas's proposed reference tariff policy:

- the allocation of total revenues to the reference and non-reference services
- the single 'postage stamp' tariff and associated cost allocation methodology
- the capacity based charging parameter
- the derivation of the reference tariff.

414 NT Gas, *Access arrangement submission*, December 2010, p. 146.

415 Santos and Magellan, *Submission to the AER*, February 2011, p. 12.

416 PWC, *Submission to the AER*, March 2011, p. 10.

The AER considers that NT Gas's proposed reference tariff and its associated cost allocation methodology are consistent with the NGR requirements for tariff setting.

Applying this structure, and incorporating the required amendments in other sections of the draft decision, the AER considers the reference tariff should be set at $0.5778 per GJ of delivery point MDQ as set out in amendment 10.1, and varied in accordance with the tariff variation mechanism, as approved in chapter 11 of the draft decision.

10.7 Required Amendments

Before the access arrangement proposal can be approved, NT Gas must make the following amendments:

- **Amendment 10.1:** Revise the 2011–12 reference tariff to $0.5778 per GJ of delivery point MDQ.

11 Tariff variation mechanism

An access arrangement is required to set out how tariffs may be varied during an access arrangement period. NT Gas has proposed a tariff variation mechanism that allows tariffs to be adjusted by inflation and, where applicable, an 'X' factor each year. In addition, NT Gas has proposed a mechanism for adjusting tariffs in the event of an approved cost pass through.

The purpose of the tariff variation mechanism is, amongst other things, to permit the building block revenues to be recovered over the access arrangement period smoothly and to take account of actual inflation.

The AER does not accept elements of NT Gas's proposed tariff variation formula, under r. 92(2) of the NGR. The AER considers the 'X' factors must be amended to reflect the changes to the forecast total revenue identified in other chapters of this draft decision.

The AER considers the proposed general cost pass through event is not defined clearly enough. Consequently, the AER has defined a number of cost pass through events it considers are preferable and has accepted the proposed materiality threshold of one per cent.

11.1 Introduction

This chapter sets out the AER's consideration of NT Gas's tariff variation mechanism. The purpose of the tariff variation mechanism is to permit tariffs to be adjusted during the access arrangement period. These adjustments are to account for actual inflation while maintaining the proportion of revenue to be recovered from different reference services. The mechanism also accommodates other tariff adjustments that may be required, such as for an approved cost pass through event. The tariff variation mechanism also sets administrative procedures for the approval of any proposed changes to tariffs.

11.2 Regulatory requirements

With respect to the tariff variation mechanism, the NGR requires that:

- NT Gas include a mechanism for variation of a reference tariff over the course of an access arrangement period (r. 92(1))
- NT Gas include the service provider's rationale for any proposed reference tariff variation mechanism (r. 72(1)(k))
- the reference tariff variation mechanism must be designed to equalise forecast revenue in present value terms from reference services over the access arrangement period, and the portion of total revenue allocated to reference services for the access arrangement period (r. 92(2))
- a reference tariff variation mechanism may provide for variation of a reference tariff in accordance with a schedule of fixed tariffs; or in accordance with a formula set out in the access arrangement; or as a result of a cost pass through for a defined event; or a combination of 2 or more of these operations. (r. 97(1))

- a formula for variation of a reference tariff may (for example) provide for variable caps on the revenue to be derived from a particular combination of reference services; or tariff basket price control; or revenue yield control; or a combination of all or any of these factors (r. 97(2))

- a reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff (r. 97(4))

- in deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the AER must have regard to the various factors under r. 97(3) of the NGR including the need for efficient tariff structures; the possible effects of the reference tariff variation mechanism on administrative costs; the regulatory arrangements (if any) applicable to the relevant reference services; the desirability of consistency between regulatory arrangements for similar services; and any other relevant factor.

The AER has full discretion in assessing NT Gas's proposed tariff variation mechanism.[417]

11.3 Access arrangement proposal

NT Gas has proposed two reference tariff variation mechanisms as part of its access arrangement proposal:

- an annual scheduled reference tariff adjustment mechanism, which applies in respect of each year of the access arrangement period

- a cost pass though reference tariff variation mechanism.[418]

NT Gas has submitted that all rates and charges for reference services will be adjusted on 1 July 2012 and on each subsequent 1 July in accordance with the approach set out in section 4.7.3 of the access arrangement.[419]

11.3.1 Annual tariff variation formula mechanism

NT Gas proposed an annual tariff variation formula mechanism that had been revised from that applying in the earlier access arrangement period. Tariffs had been previously adjusted by CPI, an X factor and a Y factor, the Y factor has been removed for the proposed access arrangement.[420] NT Gas proposed the following variation formula:

$$Reference\ Tariff_n = Reference\ Tariff_b \times (CPI_n / CPI_b) \times (1-X)$$

Where:

417 NGR r. 40(3).

418 NT Gas, *Access arrangement information*, December 2010, p. 30

419 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

420 NT Gas, *Access arrangement submission*, December 2010, p. 149; ACCC, *Final decision*, December 2002. The Y factor allowed for a one off step reduction in costs for 2006–7 to coincide with a significant step decrease in NT Gas's costs

Reference Tariff$_n$	is the Reference Tariff for the year in which the Reference Tariff is to be determined
Reference Tariff$_b$	is the Reference Tariff for Firm Service applicable at the Adjustment date of 1 July 2011
CPI	means the Consumer Price Index (weighted average, Eight Capital Cities) published quarterly by the Australian Statistician. If the Australian Statistician ceases to publish the quarterly value of that Index, then CPI means the quarterly values of another Index which Service Provider reasonably determines most closely approximates that Index.
CPI$_n$	means the value of the CPI last published before the adjustment date “n” at which the Reference Tariff is being calculated
CPI$_b$	means the base CPI, being the CPI for the quarter ended March 2011
X	is zero.[421]

As NT Gas has proposed zero X-factor growth for the entire access arrangement period, tariffs would be updated annually only by the relative magnitude of CPI compared to base year CPI, unless a cost pass through event occurs.[422]

11.3.2 Cost pass through tariff mechanism

NT Gas has included a cost pass through mechanism in its access arrangement proposal, to ensure it can recover incremental costs resulting from material unforeseeable and uncontrollable events.[423] NT Gas did not define any specific cost pass through events, opting instead for a general pass through because this:

- avoided the limitations of the foresight required to comprehensively define or forecast events
- reflected recent regulatory practice by the AER
- is consistent with the revenue and pricing principles in the NGR.[424]

NT Gas included the following example cost pass through events in its access arrangement:

- changes in regulatory obligations, or the imposition of any new regulatory obligations, including changes to applicable laws, rules and regulations;
- a change in tax or levy, or the imposition of a new tax or levy; and

421 NT Gas, *Access arrangement proposal*, December 2010, p. 13.

422 NT Gas, *Access arrangement submission*, December 2010, p. 148.

423 NT Gas, *Access arrangement submission*, December 2010, p. 150.

424 NT Gas, *Access arrangement submission*, December 2010, p. 149.

- an unusual or foreseen event, such as a flood, cyclone or earthquake, that leads to costs not otherwise recovered or recoverable through insurance or other compensation payments.[425]

11.3.2.1 Materiality threshold

NT Gas proposed that a materiality threshold equal to one per cent of smoothed annual revenue should apply to general cost pass through events.[426] NT Gas considered a one per cent threshold:

- ensured the ability for NT Gas to pass through unforeseen and uncontrollable costs

- ensured that the reference tariff reflects the efficient costs of providing the reference service

- reflected the administrative costs expected to be borne as a result of a cost pass through claim by NT Gas, its users and the AER.

- is consistent with the AER's recent regulatory practice.[427]

11.3.3 Annual tariff variation oversight and approval

NT Gas proposed a tariff variation process whereby annual changes in tariffs are notified to the AER at least 30 business days before they are scheduled to take effect. NT Gas also proposed that at the time a tariff variation is submitted to the AER for approval, it may include the impact of one or more cost pass through events.

NT Gas proposed that the AER must notify NT Gas of its decision in respect of a tariff variation notification within 30 business days of receiving a notification.[428] Otherwise, the relevant reference tariffs would be automatically varied in accordance with the notification submitted by NT Gas. However, if the AER subsequently decided against all or part of the variation, the AER may require NT Gas to amend reference tariffs to take account of the AER's decision.[429] NT Gas would only notify the AER of proposed tariff variations in accordance with either of the above mechanisms only where pipeline capacity to provide the reference service is available. Where capacity is not available, NT Gas would 'bank' CPI adjustments and cost pass through events, and submit them to the AER at such a time as capacity is available.[430]

11.4 Submissions

Santos Limited and Magellan Petroleum Australia Limited (Santos and Magellan) made a submission on NT Gas's proposed tariff variation mechanism. Santos and Magellan submitted that:

425 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

426 NT Gas, *Access arrangement submission*, December 2010, p. 152.

427 NT Gas, *Access arrangement submission*, December 2010, p. 152.

428 NT Gas, *Access arrangement submission*, December 2010, p. 153.

429 NT Gas, *Access arrangement submission*, December 2010, p. 153.

430 NT Gas, *Access arrangement submission*, December 2010, p. 153.

- the annual inflation of tariffs in line with CPI is appropriate and consistent with general regulatory practice

- cost pass through events should be limited to defined events, and be made subject to the 'approval and scrutiny' of the AER in accordance with r. 97(4).[431]

11.5 AER's considerations

NT Gas reference tariff variation mechanism is comprised of two key components; an annual tariff variation formula and a cost pass through mechanism. Each is discussed separately in the section. Rule 40(3) of the NGR provides the AER with full discretion over the proposed tariff variation mechanism. The AER can therefore reject a proposed element of the tariff variation mechanism if it considers a preferable alternative exists that better promotes the requirements in the NGR and NGL. The AER has considered the consistency of the proposed mechanism with r. 97 of the NGR; the national gas objective (NGO)[432] and the revenue and pricing principles.[433]

11.5.1 Annual tariff variation formula

The AER does not accept NT Gas's proposed annual tariff variation formula. The AER's consideration of the annual tariff variation formula is set under the following headings:

- specification of the formula

- banking of annual tariff variations

- oversight and approval

11.5.1.1 Specification of the formula

The AER accepts most aspects of NT Gas's proposed annual tariff variation formula specification. However, NT Gas has specified that tariffs for the forthcoming year be varied in accordance with the most recent inflation (CPI) figure but did not specifically identify which figures would be used. The AER requires that tariffs are to be updated using March to March CPI figures, in line with its approach to revenue calculation. NT Gas has historically adjusted reference tariffs based on March to March CPI, and the AER considers that using the most up-to-date CPI data provides consistency and therefore more accurately implements the tariff variation mechanism. Therefore, this approach better promotes the revenue and pricing principles under the NGL.[434]

NT Gas has proposed to use CPI data published in the quarter immediately preceding the scheduled tariff change (on 1 July each year).[435] Consistent with its approach in other chapters of the draft decision, the AER requires NT Gas to use March quarter

431 Santos and Magellan, *Submission on the AGP*, February 2011, pp. 13-14.

432 NGL s. 23.

433 NGL s. 24.

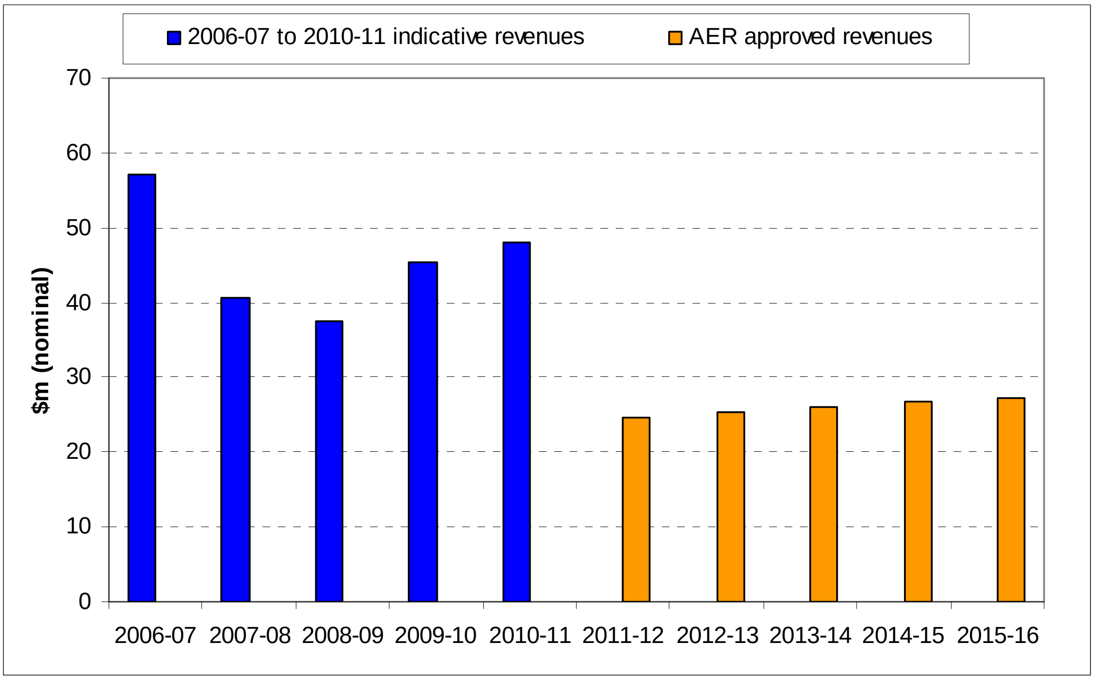
434 NGL s. 24.

435 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

CPI data for its annual tariff variations.[436] The approach to calculate the CPI adjustment is outlined in the amendment 11.1. The AER recognises that March quarter CPI will not usually be available 50 days prior to the adjustment date. To overcome this issue NT Gas should submit annual tariff variation proposals to the AER with ‘placeholder’ CPI figures, to be updated during the assessment period, when March quarter CPI is published.

NT Gas did not report a P_0 increase or decrease in 2011–12 as the proposed tariffs switch from throughput to capacity based charges.[437] The AER accepts that the 2010–11 and 2011–12 prices are not directly comparable. While prices may not be directly comparable between periods, the AER considers it would be informative to instead consider the P_0 revenue effect in 2011–12. The AER has calculated the nominal revenue requirement for NT Gas will decrease by 48 per cent between 2010–11 and 2011–12. Figure 11.1 illustrates how the revenue requirement will vary over the access arrangement period.[438]

Figure 11.1: Comparison of NT Gas’s annual revenue requirements between 2006–11 and 2011–16.



Source: AER Analysis

For the remainder of the access arrangement period, NT Gas has proposed X-factors of zero (that is, no real change in tariff during the access arrangement period). The AER considers that in the circumstances, zero X-factors reflect the flat levels of expenditures expected over the access arrangement period following the spike in the

436 NGR, r. 97(3)(e).

437 NT Gas, *Access arrangement submission*, December 2010, p. 148.

438 Note: as the pipeline was previously near fully contracted, NT Gas did not actually recover the reference service revenues in figure 11.1 from the reference service. The indicative revenues pre 2011–12 were calculated using NT Gas’s reference tariffs, adjusted backwards for actual CPI, multiplied by the actual gas throughput in the three zones.

first year. On this basis, the AER accepts the X factors proposed by NT Gas satisfy r. 97 of the NGR.

The CPI_n definition in NT Gas's proposed annual tariff variation formula should be amended as follows:

CPI_n	means the value of the CPI for the year ended 31 March in year n.

11.5.1.2 Banking of annual tariff variations

The AER does not accept NT Gas's proposal to 'bank' reference tariff variations, and only to notify the AER where spare capacity is available on the pipeline.[439] The AER considers the reference tariff should be updated annually to reflect CPI, and within a reasonable period of a cost pass through event occurring. Currently, the entire capacity of the pipeline is contracted to a single user and NT Gas has not forecast any new user connections across the access arrangement period.[440] However, the administrative costs associated with filing an annual tariff approval are likely to be minimal. By annually updating the reference tariff in line with the pre-determined X-factor and CPI, the reference tariff will always send the most efficient possible pricing signal to current or prospective users of the pipeline. This will send signals not just to reference service users, but potentially to prospective users of the negotiable services who may to some extent base their expectations of price on the reference tariff. As such, the AER considers annually updating tariffs promotes more economically efficient use of the pipeline, better promoting the revenue pricing principle of the NGL.

11.5.1.3 Oversight and approval

As outlined in amendment 11.3, NT Gas is required to provide a proposed tariff variation to the AER a minimum of 50 business days before the variation is to commence on 1 July. NT Gas, therefore, would be required to submit a tariff variation proposal on or around 15 April each year. This will provide the AER with approximately 30 business days to assess the tariff notification and provide users with 20 business days to implement the tariff changes. This is consistent with other regulatory arrangements for similar services.[441]

However, this is a short period of time for the AER to approve a tariff variation if an application is incomplete or information is not substantiated. As a result, the AER considers the access arrangement must be amended as outlined in amendment 11.3 to include a requirement to extend the decision making time period when the AER requests further information from NT Gas. The arrangements to extend the decision making time are not new, and a similar arrangement was permitted under the Code.[442]

NT Gas has proposed that if the AER does not make a decision within 30 days, the reference tariffs be automatically varied in accordance with the notification given by

439 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

440 NT Gas, *Access arrangement submission*, December 2010, p. 57.

441 NGR, r. 97(3)(d).

442 Code, annex D, s. 8.3D (b)(ii).

NT Gas.[443] The AER considers that an automatic tariff adjustment does not provide the AER with sufficient oversight or powers of approval for the annual tariff variation, and needs to be amended as outlined in amendment 11.3.[444] The AER considers 30 days to be an appropriate and reasonable time frame to make its decision in most circumstances. However, if NT Gas does not provide sufficient information to make an informed decision then automatic acceptance would not be appropriate. An automatic approval in this case would not be in the long term interests of pipeline users as it may provide an incentive for NT Gas to withhold information.

11.5.2 Cost pass through mechanism

The AER considers a cost pass through mechanism should appropriately balance the risk of material and unexpected events that impact on a service provider with the long term interests of consumers. In particular, the AER considers there should be incentives for a service provider to bear some risk of unexpected events, as this will encourage the service providers to manage or mitigate the costs associated with such events. The AER also considers that any pass through mechanism should be symmetric, such that users will benefit from unexpected events that materially reduce the costs faced by a service provider. The AER also considers that a pass through mechanism should seek to minimise any administrative costs. In combination, the AER considers these requirements of a pass through mechanism should support an efficient tariff structure, require an appropriate level of administrative costs, and promote consistency with other service providers, as required under r. 97(3) of the NGR.

The AER's considerations on cost pass through events are set out against the following sections:

- proposed cost pass through event
- defined cost pass through events
- materiality threshold
- banking of cost pass through tariff event variations
- cost pass through assessment criteria
- oversight procedures and powers of approval for the cost pass through tariff variation mechanism.

11.5.2.1 Proposed cost pass through event

The AER does not accept NT Gas's proposed cost pass through mechanism. NT Gas proposed a general pass through event, instead of proposing defined events.[445] The AER considers a general cost pass through event creates significant regulatory uncertainty and results in an imbalance such that users bear too much risk relative to

443 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

444 NGR, r. 97(4).

445 NT Gas, *Access arrangement information*, December 2010, pp. 30–31.

NT Gas. Santos and Magellan submitted that a general cost pass through event is inconsistent with rule 97(1)(c) of the NGR.[446]

NT Gas proposed that 'arbitrarily limiting the recovery of costs' associated with uncontrollable and unforseen, or able to be forecast events, is inconsistent with the revenue and pricing principles of the NGL.[447] The AER does not consider that its preferred approach of more clearly defining cost pass through events is in any way arbitrary, or inconsistent with the NGL. Clearly defining cost pass through events in advance minimises regulatory uncertainty during the access arrangement period, encouraging efficient use of and investment in the pipeline. This mitigates the possibility of a high magnitude event putting the financial viability of NT Gas at risk.[448] This aim is achieved by removing the general pass through event and replacing it with defined cost pass through events.[449] The AER considers this approach, together with the nominated pass through events listed below, will capture all high magnitude uncontrollable costs. This was the intent of the previous general nominated pass through event, and creates greater regulatory certainty for service providers, including NT Gas.[450]

The AER recognises that it has approved a general cost pass through event in previous decisions.[451] In developing the definition of the general pass through event in those decisions, the AER acknowledges that certain events were uncontrollable and unforeseeable, as noted by NT Gas.[452] This was based on an interpretation of 'foreseeable' as being about the probability of an event rather than the nature, or type, of event. This was discussed in the AER's decision for the Victorian electricity distribution network service providers' distribution determination.[453]

The AER acknowledges that not accepting the general cost pass through event proposed by NT Gas is not consistent with its decision to approve a general cost pass through for NSW gas service providers.[454] The AER is undertaking its first cycle of distribution reviews and the positions reached may take some time to settle as its regulatory approach evolves over time.[455] Noting that access arrangement periods are not concurrent across jurisdictions, any change in the AER's regulatory approach necessarily results in some inconsistency across jurisdictions for a finite period. The AER's approach to cost pass through for NT Gas is consistent with its approach in the

446 Santos and Magellan, *Submission to the AER*, February 2011, pp. 13-14.

447 NT Gas, *Access arrangement submission*, December 2010, p. 151.

448 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 718–720.

449 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 719.

450 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 722.

451 AER, *Draft decision,–Jemena* NSW gas networks, February 2010, pp. 297–298; AER, *Final decision, Queensland distribution determination*, May 2010, pp. 223–242.

452 NT Gas, *Access arrangement submission*, December 2010, p. 150.

453 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 711–712.

454 AER, *Draft decision,–Jemena access arrangement proposal for the NSW gas networks*, February 2010, p. 297.

455 AER, *Final decision, Victorian distribution determination*, October 2010, p. 795.

draft decision on the access arrangement review for the Queensland and South Australian gas distribution businesses.[456]

The AER has had regard to previous regulatory arrangements in deciding whether a particular reference tariff variation mechanism is appropriate as required by r. 97(3)(c) of the NGR. Under r. 40(3) of the NGR, the AER has full discretion to withhold approval of a proposed element if it considers a preferable alternative exists that complies with applicable requirements and criteria under the NGL. In the circumstances, the AER does not consider NT Gas's proposed general event is consistent with the objectives and requirements under the NGR and NGL.

11.5.2.2 Defined pass through events

The AER considers the following cost pass through events are preferable to NT Gas's proposed general event in their promotion of the national gas objective and revenue pricing principles.[457] The following defined events should apply in place of NT Gas's proposed events for the access arrangement period:

- Regulatory change event
- Service standard event
- Tax change event
- Terrorism event
- Insurer credit risk event
- Insurance cap event
- Natural disaster event.

These events are defined in amendment 8.2.

11.5.2.3 Materiality threshold

The AER accepts NT Gas's proposed materiality threshold, set at one per cent of smoothed forecast revenue.[458] A clear and defined threshold reduces uncertainty in assessing the materiality of a cost pass through event, and one per cent has regularly been accepted as a reasonable gauge of materiality by the AER and other jurisdictional regulators.[459] The AER considers the one per cent materiality threshold promotes an equitable distribution of risk between NT Gas and it users; while retaining the incentive for NT Gas to employ prudent risk management and associated cost mitigation. For these reasons, the AER considers that a one per cent materiality threshold is consistent with the requirements of the national gas objective, and the

456 AER, *Draft decision–Envestra's Qld network*, February 2011, p. 191; AER, *Draft decision–Envestra's SA network*, February 2011, p. 209; AER, *Draft decision–APT Allgas*, February 2011, p. 138.

457 NGL s. 23 and NGL s. 24 .

458 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

459 QCA, *Final decision, Regulation of electricity distribution*, April 2005, p. 50; IPART, *NSW Electricity distribution pricing 2004–05 to 2008–09*, June 2004, p. 29.

NGL revenue and pricing principles.[460] The AER also considers the description of the materiality threshold should be defined to be consistent with previous AER decisions. This will reduce uncertainty in the AER's assessment of whether events qualify as material.

11.5.2.4 Banking of cost pass through tariff variations

The AER does not accept NT Gas's proposal to bank cost pass through tariff variations as it does not promote the long term interests of users and prospective users as required under the national gas objective. Where a cost pass through event occurs, the AER considers it is preferable that NT Gas notifies the AER within a reasonable period of the event occurring. The reasons for this are as follows:

- Cost pass through events are included in the tariff variation mechanism to protect the service provider and users, in case a significant unforeseeable event were to put the financial viability of the service provider at risk. 'Banking' the effects of such an event would notionally delay cost recovery, which is inconsistent with the mechanism.

- Information necessary for the AER's assessment of a cost pass through event is likely to be most readily available closer to the occurrence of the event. 'Banking' a cost pass through event would therefore increase the difficulty and administrative costs of an effective assessment.

11.5.2.5 Cost pass through assessment criteria

In the access arrangement proposal, NT Gas submitted that reference tariffs may be varied if one or more cost pass through events occur, or are reasonably expected to occur.[461] Likewise, NT Gas proposed that the impact of events that 'are expected to lead to changes in costs' can be passed through.[462] The AER does not accept these descriptions, and considers that the cost pass through mechanism should only apply to events that have occurred. The AER considers the purpose of cost pass through is to provide service providers the ability to recover efficient costs incurred in events that could be firmly defined in advance, but where the timing and scope of the events were not foreseeable. Reimbursement for impacts that have not yet occurred would not achieve this purpose.

The AER considers that NT Gas's proposed description of cost pass through arrangements is not sufficiently clear to end users. The AER considers that the access arrangement proposal should set out factors the AER must take into consideration when assessing whether an event is a cost pass through event. These are:

- the costs to be passed through are for the delivery of pipeline services

- the cost are incremental to costs already allowed for in reference tariffs

- the total costs to be passed through are building block components of total revenue

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460 NGL s. 23 and NGL s. 24.

461 NT Gas, *Access arrangement proposal*, December 2010, p. 13.

462 NT Gas, *Access arrangement proposal*, December 2010, p. 14.

- the costs to be passed through meet the relevant NGR criteria for determining the building block for total revenue in determining reference services

- any other factors the AER considers relevant and consistent with the NGL and NGR.[463]

NT Gas's access arrangement proposal also needs to include a requirement to provide the AER with a statement verifying that the costs of any pass through events are net of any payments made by an insurer or third party which partially or wholly offset the financial impact of that event (including self insurance). This is to ensure that only the net financial impact of an event is considered for pass through, as the financial impact of some events may be partially or wholly compensated or reimbursed by insurers or third parties as outlined in amendment 11.4.

11.5.2.6 Oversight procedures and powers of approval for the cost pass through tariff variation mechanism

Rule 97(4) of the NGR requires that the reference tariff variation mechanism must give the AER sufficient powers of oversight or approval. The AER does not consider NT Gas's proposed procedures for cost pass through variations meet this requirement.

The AER considers that it must be notified of a pass through event within 90 business days of the costs being incurred. The AER considers it should notify NT Gas of its decision on any cost pass through application within 90 days, except where the AER considers the pass through application is sufficiently complex as to require an extension. The AER will notify NT Gas where this is the case—and of the anticipated duration of the extension—within 90 business days of being notified of the pass through application. The AER considers the time frames described above should balance the need for a timely response, with the flexibility to make a complete and informed assessment of a cost pass through application.

The AER considers that procedures for the variation of reference tariffs due to cost pass through events should be separated from the general discussion of procedures for tariff variation as set out in amendment 11.4. The AER considers this will improve the clarity of the process and requirements for NT Gas and for network users.

11.6 Conclusion

The AER does not accept elements from NT Gas's proposed tariff variation mechanism, including:

- annual tariff variation formula specification (section 11.5.1.1)

- general cost pass through event (section 11.5.2.1)

- 'banking' of tariff variations (section 11.5.3.1) and cost pass through variations (section 11.5.2.4)

- cost pass through assessment criteria (section 11.5.2.5)

463 AER, *Draft decision–Jemena access arrangement proposal for the NSW gas networks*, February 2010, p. 301; NGR, r. 97(3)(e).

- powers of oversight and approval by the AER (sections 11.5.1.3 and 11.5.2.6).

However, the AER accepts NT Gas's proposed materiality threshold for cost pass through events.

11.7 Required amendments

Before the access arrangement proposal can be accepted, NT Gas must make the following amendments:

Amendment 11.1: amend section 4.7.1 of the access arrangement proposal as follows:

The Reference Tariff for the Firm Service to apply on 1 July 2012 and on each subsequent 1 July will be adjusted according to the following formula:

$$Reference\ Tariff_n = Reference\ Tariff_b \times (CPI_n / CPI_b) \times (1-X)$$

Where:

Reference Tariff$_n$	is the Reference Tariff for the year (n) in which the Reference Tariff is to be determined
Reference Tariff$_b$	is the Reference Tariff for the Firm Service applicable at the Adjustment date of 1 July 2011
CPI	means the Consumer Price Index (weighted average, Eight Capital Cities) published quarterly by the Australian Statistician. If the Australian Statistician ceases to publish the quarterly value of that Index, then CPI means the quarterly values of another Index which Service Provider reasonably determines most closely approximates that Index.
CPI_n	means the value of the CPI for the year ended March 31 in year n.
CPI_b	means the base CPI, being the CPI for the quarter ended March 31 2011.
X	*is 0.*

Amendment 11.2: delete section 4.7.2 of the access arrangement proposal and include the following:

Subject to the approval of the AER under the NGR, Reference Tariffs may be varied after one or more Cost Pass-through Event/s occurs, in which each individual event materially increases or materially decreases the cost of providing the reference services. Any such variation will take effect from the next 1 July.

In making its decision on whether to approve the proposed Cost Pass-through Event variation, the AER must take into account the following:

- the costs to be passed through are for the delivery of pipeline services
- the costs are incremental to costs already allowed for in reference tariffs
- the total costs to be passed through are building block components of total revenue
- the costs to be passed through meet the relevant National Gas Rules criteria for determining the building block for total revenue in determining reference services
- any other factors the AER considers relevant and consistent with the NGR and NGL.

For the purpose of any defined event, an event is considered to materially increase or decrease costs where that individual event has an impact of one per cent of the smoothed forecast revenue specified in the access arrangement information, in the years of the access arrangement period that the costs are incurred.

Cost Pass-through Events are:

- a regulatory change event;
- a service standard event;
- a tax change event;
- a terrorism event;
- an insurer credit risk event;
- an insurance cap event;
- a natural disaster event;

Where

Regulatory change event—means:

A change in a regulatory obligation or requirement that:

(a) occurs during the course of the access arrangement period; and

(b) substantially affects the manner in which NT Gas provides reference services; and

(c) materially increases or materially decreases the costs of providing those services.

Service standard event—means:

A legislative or administrative act or decision that:

(a) has the effect of:

(i) substantially varying, during the course of the access arrangement period, the manner in which NT Gas is required to provide a reference service; or

(ii) imposing, removing or varying, during the course of the access arrangement period, minimum service standards applicable to reference services; or

(iii) altering, during the course of the access arrangement period, the nature or scope of the reference services, provided by NT Gas; and

(b) materially increases or materially decreases the costs to NT Gas of providing reference services.

Tax change event—means:

A tax change event occurs if:

(a) any of the following occurs during the course of the access arrangement period for NT Gas:

(i) a change in a relevant tax, in the application or official interpretation of a relevant tax, in the rate of a relevant tax, or in the way a relevant tax is calculated;

(ii) the removal of a relevant tax;

(iii) the imposition of a relevant tax; and

(b) in consequence, the costs to NT Gas of providing reference services are materially increased or decreased.

A relevant tax is any tax payable by NT Gas, other than:

(a) income tax and capital gains tax;

(b) stamp duty, financial institutions duty and bank accounts debits tax;

(c) penalties, charges, fees and interest on late payments, or deficiencies in payments, relating to any tax; or

(d) any tax that replaces or is the equivalent of or similar to any of the taxes referred to in paragraphs (a) to (b) (including any State equivalent tax).

Terrorism event—means:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of in connection with any organisation or government), occurring during the access arrangement period, which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and or put the public, or any section of the public, in fear) and which materially increases the costs to NT Gas of providing a reference service.

Insurer credit risk event—means:

An event where the insolvency of the nominated insurers of NT Gas occurs, as a result of which NT Gas:

(a) incurs materially higher or lower costs for insurance premiums than those allowed for in the access arrangement; or

(b) in respect of a claim for a risk that would have been insured by NT Gas's insurers, is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.

Insurance cap event—means:

An event that would be covered by an insurance policy but for the amount that materially exceeds the policy limit, and as a result NT Gas must bear the amount of that excess loss. For the purposes of this cost pass through event, the relevant policy limit is the greater of the actual limit from time to time and the limit under NT Gas's insurance cover at the time of making this access arrangement. This event excludes all costs incurred beyond an insurance cap that are due to NT Gas's negligence, fault, or lack of care. This also excludes all liability arising from NT Gas's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by NT Gas.

Natural disaster event—means:

Any major fire, flood, earthquake, or other natural disaster beyond the control of NT Gas (but excluding those events for which external insurance or self insurance has been included within NT Gas's forecast operating expenditure) that occurs during the access arrangement period and materially increases the costs to NT Gas of providing reference services.

Materiality threshold is defined as:

For the purpose of any defined event, an event is considered to materially increase or decrease costs where that event has an impact of one per cent of the smoothed forecast revenue specified in the final decision, in the years of the access arrangement period that the costs are incurred.

Amendment 11.3: rename section 4.7.3 as 'Tariff adjustment process for annual tariff variation', and amend as follows:

NT Gas will notify the AER in respect of any Reference Tariff variations, such that variations occur on the first of July of any year. The notification will be made at least 50 business days before the date of implementation and include:

(a) the proposed variations to the Reference Tariffs; and

(b) an explanation and details of how the proposed variations have been calculated.

If NT Gas proposes variations to the Reference Tariffs (other than as a result of a Trigger Event) and those variations have not been approved by the next 1 July then the Reference Tariffs will be varied with effect from that next 1 July by the same percentage increment or decrement as occurred on the previous 1 July, until such time as variations to Reference Tariffs are approved by the AER.

If it appears that any past tariff variation contains a material error or deficiency because of a clerical mistake, accidental slip or omission, miscalculation or misdescription, the AER may change subsequent tariffs to account for these past issues.

Within 30 business days of receiving NT Gas's variation notice, the AER will inform NT Gas in writing of whether or not it has verified the proposed reference tariff.

The 30 business day periods may be extended for the time taken by the AER to obtain information from the Service Provider, obtain expert advice or consult about the notification. However, the AER must assess a cost pass through application within 90 business days, including any extension of the decision making time.

Amendment 11.4: insert a new section after 4.7.3 in the access arrangement proposal as follows:

4.7.4 Tariff adjustment process for cost pass through events

NT Gas will notify the AER of cost pass through events within 90 business days of those costs being incurred, whether the costs would lead to an increase or decrease in Reference Tariffs.

When making a notification to the AER, NT Gas will provide the AER with a statement, signed by an authorised officer of NT Gas, verifying that the costs of any pass through events are net of any payments made by an insurer or third party which partially or wholly offsets the financial impact of that event (including self insurance).

The AER must notify NT Gas of its decision to approve or reject the proposed variations within 30 business days of receiving the notification. This period will be extended for the time taken by the AER to obtain information from NT Gas, obtain expert advice or consult about the notification.

The AER will endeavour to make its decision on whether NT Gas should vary Reference Tariffs due to the occurrence of a cost pass through event within 90 business days of receiving a notification from NT Gas. However, if the AER determines the difficulty of assessing or quantifying the effect of the relevant cost pass through event requires further consideration, the AER may require an extension of a specified duration. The AER will notify NT Gas of the extension, and its duration, within 90 business days of receiving a notification from NT Gas.

Amendment 11.5: amend the access arrangement information to reflect amendments 11.1–11.4 as appropriate.

Part C—Other provisions of an access arrangement

12 Non–tariff components

NT Gas's access arrangement sets out proposed terms and conditions that are not directly related to the nature or level of tariffs paid by users, but which are important to the relationship between the pipeline service provider and users. NT Gas has substantially revised the terms and conditions from those included in the earlier access arrangement.

The AER proposes to approve some of the terms and conditions of NT Gas's access arrangement proposal. However, the AER proposes not to approve a number of the terms and conditions. The AER considers that amended provisions for these terms and conditions better promote the national gas objective under s. 23 of the NGL. The AER considers that the national gas objective requires the AER to balance the interests of the service provider and users.

The AER proposes not to approve a number of the non-tariff components of NT Gas's access arrangement proposal, including: capacity trading requirements; queuing requirements; extensions and expansions policy; and the commencement and review submission dates. The AER considers that amended arrangements for these components better promote the national gas objective under s. 23 of the NGL.

12.1 Introduction

This chapter sets out the AER's consideration of the non-tariff components of NT Gas's access arrangement proposal. In order to demonstrate compliance with r. 48 of the NGR, NT Gas's access arrangement proposal includes:

- the terms and conditions that form the basis of the relationship between NT Gas and its users;
- capacity trading arrangements that allow users to transfer contracted capacity to other users;
- queuing requirements that set out a process for establishing the order of priority between prospective users of any spare (or developable) capacity;
- a policy that addresses whether any extension to, or expansion of, the network will be treated as part of the covered pipeline and what the impact on tariffs will be;
- the terms and conditions for changing receipt and delivery points; and
- dates for submitting the next access arrangement for review and commencing the next access arrangement.

NT Gas's proposed terms and conditions are covered in this chapter and in appendix C. This chapter also addresses NT Gas's proposed capacity trading requirements, queuing requirements, extensions and expansions policy and commencement and review dates. The terms and conditions for changing receipt and delivery points are part of NT Gas's proposed capacity trading requirements.

12.2 Terms and conditions

12.2.1 Regulatory requirements

Rules 48(1)(d)(i) and 48(1)(d)(ii) of the NGR require a full access arrangement to specify the reference tariff and other terms and conditions on which reference services will be provided.

There are no specific rules in the NGR that guide the AER's assessment of proposed non-tariff terms and conditions. However, in considering NT Gas's proposed terms and conditions the AER has had regard to r. 100 of the NGR.

Rule 100 of the NGR requires that an access arrangement be consistent with the national gas objective[464] and the rules and procedures in force when the terms and conditions of the access arrangement proposal are determined or revised. The national gas objective 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 price, quality, safety, reliability and security of supply of natural gas.[465]

The AER has full discretion in assessing NT Gas's proposed terms and conditions. Full discretion means that the AER has discretion to withhold its approval to an element of an access arrangement proposal if, in the AER's opinion, a preferable alternative exists that:

- complies with applicable requirements of the NGL and NGR
- is consistent with applicable criteria (if any) prescribed by the NGL and NGR.[466]

12.2.2 Access arrangement proposal

NT Gas's proposed terms and conditions are set out in schedule 3 of the access arrangement.[467] The proposed terms and conditions provide the basis of the access agreement between NT Gas and a user.[468] NT Gas has substantially revised the terms and conditions of its access arrangement, submitting that consideration should be given to the fact that the terms and conditions of the earlier access arrangement were drafted more than ten years ago.[469] NT Gas has further submitted that the terms and conditions of the earlier access arrangement period no longer correspond to NT Gas's gas transportation arrangements, and that the proposed terms and conditions better reflect its current arrangements.

12.2.3 Submissions

The AER received two submissions on NT Gas's proposed terms and conditions. These were from:

464 NGL, s. 23.

465 NGL, s. 23.

466 NGR, r. 40(3).

467 NT Gas, *Access arrangement*, December 2010, pp. 32–46.

468 NT Gas, *Access arrangement*, December 2010, pp. 32–46.

469 NT Gas, *Access arrangement submission*, December 2010, p. 13.

- Santos Limited and Magellan Petroleum Australia Limited (Santos and Magellan)[470]

- Power and Water Corporation (PWC). [471]

Santos and Magellan and PWC all agreed that NT Gas's revisions to the terms and conditions appeared to be heavily biased in favour of the service provider.[472] PWC submitted that proposed terms and conditions do not reflect terms typical of a freely negotiated gas transportation agreement.[473] Santos and Magellan also submitted that the proposed terms and conditions are designed to re-allocate risk from the service provider to the user and that it does not agree that users and prospective users would benefit from the revisions to the terms and conditions.[474]

The AER's consideration of the submissions is outlined in detail in appendix C.

12.2.4 AER's considerations

The AER's assessment of NT Gas's proposed terms and conditions is set out in detail in appendix C.

The AER considers that in order to achieve the national gas objective[475] the interests of both consumers and gas pipeline service providers need to be taken into account. On the one hand, charges and non-price terms and conditions that unduly favour the gas pipeline service providers are not consistent with the promotion of efficient investment in and efficient operation of natural gas services and are not consistent with the long term interests of consumers. On the other hand, if tariffs, other charges and non-price terms and conditions are weighted in favour of users without due regard to the interests of gas pipeline service providers, service providers may be unwilling to make adequate investment in the pipeline or provide adequate services. This would not be in the long term interests of natural gas consumers.

Overall, the AER agrees with Santos, Magellan and PWC that taken in aggregate the proposed terms and conditions are weighted too much in favour of NT Gas. To correct this imbalance the AER requires NT Gas to amend a number of terms and conditions. The amendments required are set out in detail in appendix C.

12.3 Capacity trading requirements

A capacity trading policy allows a user to transfer contract capacity to another user. In doing so, it enables a secondary market with more efficient price signals and levels of usage. As service providers do not gain directly from capacity trading, the NGR protects users' rights to trade flexibly and limits the service provider's power to deny this right.

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470 Santos and Magellan, *Submission to the AER*, February 2010, pp. 4–10.

471 PWC, *Submission to the AER*, February 2010, pp. 13–22.

472 Santos and Magellan, *Submission to the AER*, February 2010, p. 4; PWC, *Submission to the AER*, February 2010, p. 13.

473 PWC, *Submission to the AER*, February 2010, p. 13.

474 Santos and Magellan, *Submission to the AER*, February 2010, p. 4.

475 NGL, s. 23.

12.3.1 Regulatory requirements

Under r. 48(1)(f) of the NGR capacity trading requirements are to be included in a full access arrangement. The terms and conditions for changing receipt and delivery points must also be included in a full access arrangement under r. 48(1)(h) of the NGR.

Rule 105(1) of the NGR requires that capacity trading requirements must provide for capacity transfers in accordance with the rules or procedures of the relevant gas market, if the service provider is registered as a participant in a particular gas market. If the service provider is not registered, or the rules or procedures do not address capacity trading, then capacity trading requirements must comply with r. 105 of the NGR.

Rules 105(2) and 105(3) of the NGR concern the transfer of capacity trading requirements with and without the service provider's consent. Capacity trading requirements may specify conditions under which consent will or will not be given, and the conditions to be complied with if consent is given. A service provider is precluded from withholding its consent unless it has reasonable grounds, based on technical or commercial considerations, for doing so.[476]

Rule 106 of the NGR requires that an access arrangement must provide for the change of a receipt or delivery point with the service provider's consent. The service provider is precluded from withholding its consent unless it has reasonable grounds, based on technical or commercial considerations, for doing so. The access arrangement may specify conditions under which consent will or will not be given and conditions to be complied with if consent is given.[477]

12.3.2 Access arrangement proposal

NT Gas has proposed that where the relevant parties are registered as participants in a particular gas market, then capacity transfers will occur in accordance with the procedures or rules of that market.[478]

NT Gas has also proposed conditions under which users can make capacity transfers by way of subcontract or other methods.[479] Further, NT Gas has proposed that the conditions under which a user can request substitution of its capacity from one delivery point to another, or one receipt point to another.[480]

12.3.3 AER's considerations

12.3.3.1 Definitions

NT Gas does not provide a definition for the term *reasonable commercial or technical grounds* used in section 5.4 of its access arrangement proposal. The AER considers that users and prospective users would benefit from a definition of this term as it is the basis on which NT Gas may withhold its consent to user requests for changing

476 NGR, r. 105(4).

477 NGR, r. 106.

478 NT Gas, *Access arrangement*, December 2010, p 16.

479 NT Gas, *Access arrangement*, December 2010, pp. 16–17.

480 NT Gas, *Access arrangement*, December 2010, pp. 16–17.

delivery and receipt points. The definition of the term *reasonable commercial or technical grounds* is included in the approved access arrangement for another APA Group owned and operated transmission pipeline.[481] The AER considers that the provision of such a definition in the proposed access arrangement would better promote the national gas objective under s. 23 of the NGL.

12.3.3.2 Capacity trading requirements

The AER considers that section 5.1 and sections 5.2(a) and (b) of NT Gas's proposed access arrangement appropriately facilitate capacity trading and, as they largely repeat the requirements set out under r. 105 of the NGR, they are compatible with the national gas objective.[482]

Section 5.3 of NT Gas's proposed access arrangement sets out a number of requirements for the trading of capacity between users and third parties. The AER considers that NT Gas is able to specify conditions under which capacity trading may occur. However, the AER also has full discretion in this area, and may withhold its approval of any element of the capacity trading provisions if preferable alternatives exist. The AER considers that sections 5.3(b), 5.3(c), 5.3(d), 5.3(e) and 5.3(h) of the proposed access arrangement are reasonable requirements and accepts these sections.

However, the AER does not accept section 5.3(a) of NT Gas's proposed access arrangement. The AER considers that the term *without limitation* used in the context of NT Gas's legal and internal costs that users are obliged to pay for application of consent, implies greater coverage and goes beyond what could be considered as reasonable costs. Therefore, the AER considers that the term *without limitation* should be deleted from section 5.3(a).

The AER also does not accept section 5.3(g) of NT Gas's proposed access arrangement. The AER considers that not allowing trading of capacity where a user is in default under its transportation agreement may restrict the efficient transfer of capacity between existing and potential users of natural gas. The AER considers that as the trading of capacity does not affect the liabilities of a user to the service provider that accrue prior to the transfer taking place,[483] restriction of a user from capacity trading would not benefit the service provider or the user in the event of a user's default. Furthermore, restrictions placed on a user from capacity trading at a time of default may further hinder the user in making efforts to improve its financial situation.

The AER approves section 5.4 of the access arrangement subject to inclusion of a definition for "reasonable commercial or technical grounds".

12.3.4 Conclusion

The AER proposes not to approve NT Gas's proposed capacity trading requirements. The AER considers amended requirements could better promote the national gas objective in accordance with s. 23 of the NGL.

481 APT Petroleum Pipelines Limited, *Access arrangement for Roma Brisbane Pipeline*, 28 March 2007, p 19.

482 NGL, s. 23.

483 NGR, r. 105(5).

12.3.5 Required amendments

Before the access arrangement proposal can be approved, NT Gas must make the following amendments.

Amendment 12.1: amend section 5.3(a) of the capacity trading requirements of the access arrangement proposal by deleting the term *without limitation*

Amendment 12.2: delete section 5.3(g) of the capacity trading requirements of the access arrangement proposal

Amendment 12.3: amend schedule 2 of the access arrangement proposal by including a definition of the term *reasonable commercial or technical grounds*

12.4 Queuing requirements

Queuing can be used to determine access to a pipeline that is fully, or close to being fully, utilised. Queuing requirements will establish a process or mechanism for establishing the order of priority between prospective users of any spare (or developable) capacity.

12.4.1 Regulatory requirements

Under r. 48(1)(e) and r. 103(1) of the NGR queuing requirements are to be included in a full access arrangement if the access arrangement is for a transmission pipeline.

Rule 103(3) of the NGR requires that queuing requirements must establish a process or mechanism for determining an order of priority between prospective users of spare capacity or developable capacity in which all prospective users are treated on a fair and equal basis.

Rule 103(4) of the NGR provides by way of example that the order of priority may be determined either on a first come first serve basis or on the basis of a publicly notified auction in which all prospective users are able to participate.

Rule 103(5) of the NGR requires that queuing requirements must be sufficiently detailed to enable a prospective user to understand the basis of the order of priority and to determine its position in the queue.

12.4.2 Access arrangement proposal

NT Gas's proposed queuing requirements include responsibilities such as advising a prospective user of its position in the queue and advising when capacity will become available. [484] These requirements set out the conditions of queuing, the method of determining priority of requests, the procedure to be undertaken once capacity can be made available and other general considerations.

484 NT Gas, *Access arrangement*, December 2010, pp. 18–19.

12.4.3 AER's consideration

The AER considers that most of NT Gas's proposed queuing requirements are satisfactory, however there is one element of these requirements that the AER does not accept. In the last paragraph of section 6.4 of the proposed access arrangement, NT Gas has proposed that a user will be given first priority if it exercises a contractual right in force as at 5 February 2003 to increase its capacity reservation under its existing transportation agreement. The date '5 February 2003' is the commencement date of the earlier access arrangement. The AER considers that this date should be updated to reflect the commencement of the proposed access arrangement.

The AER proposes not to approve NT Gas's proposed queuing requirements as they do not comply with r. 103 of the NGR. The AER considers that the required amendments will better promote the national gas objective under s. 23 of the NGL.

12.4.4 Required amendment

Before the access arrangement proposal can be approved, NT Gas must make the following amendment.

Amendment 12.4: amend section 6.4 of the queuing requirements of the access arrangement proposal by replacing the date '5 February 2003' with the commencement date of the access arrangement.

12.5 Extensions and expansions policy

An extensions and expansions policy sets out the method for determining whether extensions or expansions to the covered pipeline are to be covered by the access arrangement. Where an extension or expansion is determined to be covered, the policy determines how the use of that extension or expansion will be priced.

12.5.1 Regulatory requirements

Under r. 48 of the NGR extension and expansion requirements are to be included in a full access arrangement.[485] Rule 104(1) of the NGR requires that extension and expansion requirements may state whether the applicable access arrangement will apply to incremental services provided as a result of a particular extension or expansion or outline how this may be dealt with at a later time. If the requirements provide that an access arrangement applies to incremental services, r. 104(2) of the NGR states that the requirements must deal with the effect of the extension or expansion on tariffs.

12.5.2 Access arrangement proposal

NT Gas has proposed an extensions and expansions policy which has more requirements and is more detailed than that set out in the earlier access arrangement. The policy sets out that in the event of an extension or expansion, the access arrangement will apply to any incremental services provided unless NT Gas, with the agreement of the AER, agrees that it should not.[486]

485 NGR, r. 48(1)(g).

486 NT Gas, *Access arrangement*, December 2010, p. 20.

The proposed extensions and expansions policy allows the service provider to determine whether incremental services enabled by an extension or expansion are to be treated as a negotiated service or a reference service, and priced at a negotiated tariff or the reference tariff respectively. The proposed policy includes fixed principles, whereby the capital expenditure (capex), operating costs and usage associated with an expansion or extension offered as a negotiated service will not be considered in the calculation of the reference tariff. The proposed policy also states that reference tariffs in the access arrangement period will not be affected by any extension or expansion made.[487]

12.5.3 Submissions

In its joint submission, Santos and Magellan expressed concerns that the non-coverage of the incremental expansion in capacity and of assets that allowed for the expansion in capacity may give rise to discriminatory pricing between existing and new users. This is because of the different allocation of costs between existing and incremental capacity to provide services. Santos and Magellan submitted that this has recently occurred for the Goldfields Gas Pipeline in Western Australia under an access arrangement that was approved by the Western Australian Energy Regulatory Authority.[488]

Santos and Magellan further submitted that the AER should review this element of NT Gas's extensions and expansions policy and the implications for consistency with the revenue and pricing principles and the national gas objective.[489]

The Northern Territory Major Energy Users (NTMEU) submitted that if any capex included in the access arrangement is used for the expansion of pipeline capacity, then that expansion capacity must be included in the access arrangement.[490]

12.5.4 AER's consideration

The AER does not accept NT Gas's proposed extensions and expansions requirements. Under r. 40(3) of the NGR, the AER has full discretion to impose preferable extension and expansion requirements in an access arrangement review where they also comply with applicable requirements and criteria under the NGL and the NGR. The AER considers that an amended version of NT Gas's access arrangement proposal would better promote the national gas objective.[491]

Consistent with its previous decisions[492] the AER considers that unlike extensions, all expansions to the pipeline should be covered by default. Pipeline expansions involve the augmentation of pipeline capacity of the existing pipeline, and are likely to be used by the existing pipeline users. Relative to pipeline extensions, they are much less

487 NT Gas, *Access arrangement*, December 2010, p. 20.

488 Santos and Magellan, *Submission to the AER*, February 2010, p. 13.

489 Santos and Magellan, *Submission to the AER*, February 2010, p. 13.

490 NTMEU, *Submission to the AER*, February 2010, p. 62.

491 NGL, s. 23.

492 AER, *Draft decision–APT Allgas*, February 2011, p. 166; AER, *Draft decision–Envestra's SA network*, February 2011, p. 246; AER, *Draft decision–Envestra's Qld network*, February 2011, p. 227; AER, Draft Jemena Gas Network draft decision, February 2010, pp. 348–350; AER, ActewAGL draft decision, November 2009, pp. 185–186; AER, Country Energy draft decision, November 2009, pp. 140–141.

likely to serve a new or isolated customer as a bypass option. As such, it is appropriate that all pipeline expansions form part of the covered pipeline and that the pipeline services offered with these expansions be covered under the access arrangement.

The AER also considers that NT Gas should notify the AER of all extensions or expansions completed or in progress at the end of each financial year. The AER considers this level of transparency is necessary to satisfy the national gas objective.[493] NT Gas's proposal contains no such provisions, and the AER requires NT Gas to amend sections 7.1 and 7.2 of the access arrangement accordingly.

The AER considers that sections 7.1(a), 7.1(b), 7.1(c), 7.1(d), 7.2(a), 7.2(b), 7.2(c) and 7.3 of the proposed access arrangement are reasonable requirements and accepts these sections.

However, the AER does not accept section 7.4 of the proposed access arrangement which relates to fixed principles. In section 7.4 NT Gas has proposed that sections 7.1(d) and 7.2(c) are established as fixed principles from the commencement of the access arrangement for a period of 15 years or to such other date as advised.[494] Sections 7.1(d) and 7.2(c) specifies that the capital investment, operating costs and usage associated with extensions and expansions and offered as a negotiated service will not be considered in the calculation of the reference tariff. While agreeing that costs associated with extension and expansions should not be included in the calculation of the reference tariff where pipeline services are offered to users as negotiated services, the AER rejects the proposal to establish this condition as a fixed principle.

The AER considers that there is merit in monitoring the operation of NT Gas's extensions and expansions policy. At the next access arrangement review an assessment should be carried out to determine:

- how effective the extensions and expansions policy was during the previous period
- whether the extensions and expansions policy needs to be modified to increase its effectiveness.

The extensions and expansions policy may need to be amended after this assessment to ensure that it operates as necessary to fulfil the requirements of r. 104 of the NGR. The establishment of fixed principles would prevent any required changes to the requirements dealing with costs associated with negotiated services offered on pipeline extensions and expansions.

The AER has also considered the possible concern over regulatory certainty[495] which may arise if these requirements of the extension and expansion policy are not implemented as fixed principles but considers the risk to be low. Even without these

493 NGL, s. 23.

494 NT Gas, *Access arrangement*, December 2010, p. 20.

495 NT Gas, *Access arrangement submission*, December 2010, p. 14.

requirements as being fixed principles, section 7.3 of the proposed access arrangement provides that over the access arrangement period reference tariffs will not be affected by any extension or expansion made.

Santos and Magellan had concerns about the non-coverage of incremental expansion in capacity and how this may give rise to discriminatory pricing between existing and new users. The AER agrees with Santos and Magellan that there may be potential for price discrimination because of the possibility of different cost allocations for the provision of pipeline services between existing and incremental capacity. However, the AER is satisfied that section 7.2(a) of the proposed access arrangement contains a sufficient safeguard to prevent this from occurring in that the AER would have to agree to the non-coverage of incremental pipeline expansion above the existing capacity. In deciding whether to approve the non-coverage of incremental expansion the AER would consider amongst other things the likely impact on existing and prospective users under the national gas objective and the revenue and pricing principles of the NGL.[496]

With respect to the NTMEU submission the AER notes that NT Gas is not proposing any capital expenditure for pipeline expansion or extension in the access arrangement period.

The AER, therefore, proposes not to approve NT Gas's proposed extensions and expansions policy. The AER considers an amended policy would better promote the national gas objective under s. 23 of the NGL.

12.5.5 Required amendments

Before the access arrangement proposal can be approved, NT Gas must make the following amendments.

Amendment 12.5: amend section 7.1 of the access arrangement proposal as follows:

If NT Gas proposes an extension of the covered pipeline, it must apply to the AER in writing to decide whether the proposed extension will be taken to form part of the covered pipeline and will be covered by this access arrangement.

A notification given by NT Gas under this section 7.1 must:

a) be in writing

b) state whether NT Gas intends for the proposed pipeline extension to be covered by this Access Arrangement

c) describe the proposed pipeline extension and describe why the proposed extension is being undertaken and

d) be given to the AER before the proposed pipeline extension comes into service.

496 NGL, ss. 23 and 24.

NT Gas is not required to notify the AER under this section 7.1 to the extent that the cost of the proposed pipeline extension has already been included and approved by the AER in the calculation of Reference Tariffs.

After considering NT Gas's application, and undertaking such consultation as the AER considers appropriate, the AER will inform NT Gas of its decision on NT Gas's proposed coverage approach for the pipeline extension.

The AER's decision referred to above, may be made on such reasonable conditions as determined by the AER and will have the effect stated in the decision.

Amendment 12.6: amend section 7.1 of the access arrangement proposal as follows:

No later than 20 Business Days following the expiration of its financial year, NT Gas must notify the AER of all pipeline extensions during that financial year, including all extensions commenced, in progress and completed. The notice must describe each extension and set out why this was necessary.

Amendment 12.7: amend section 7.2(a) of the access arrangement proposal by deleting the words '.. unless Service Provider proposes and the Regulator agrees that this Access Arrangement will not apply to the incremental Services provided as a result of that Expansion.'

Amendment 12.8: amend section 7.2 of the access arrangement proposal as follows:

No later than 20 Business Days following the expiration of its financial year, NT Gas must notify the AER of all pipeline expansions during that financial year, including all expansions commenced, in progress and completed. The notice must describe each expansion and set out why this was necessary.

Amendment 12.9: delete section 7.4 of the extensions and expansions policy of the access arrangement proposal which relates to fixed principles.

12.6 Commencement and review dates

The NGR includes a general rule that the proposed access arrangement period will apply for at least five years and be reviewed after four years,[497] or sooner in the event of certain triggers.[498] A five year period between reviews provides regulatory certainty for service providers, in terms of the commercial parameters they operate within, as well as for users, in terms of the price and conditions of access to the regulated network.

12.6.1 Regulatory requirements

Rule 49(1) of the NGR requires that a full access arrangement that is not voluntary must contain a review submission date and a revision commencement date and must not contain an expiry date.

497 NGR, r. 50.

498 NGR, r. 51.

The general rules, set out under r. 50(1) of the NGR, is that a review submission date will fall four years after the access arrangement took effect or the last revision commencement date, and a new revision commencement date will fall one year later.[499] The AER is required to accept a service provider's proposed review submission and commencement dates if these are made in accordance with the general rule.[500] It may also approve dates that do not conform to the general rule if it is satisfied that the dates are consistent with the national gas objective and the revenue and pricing principles.[501]

The review submission date may occur in advance of that fixed in the access arrangement if a specified trigger event occurs.[502] Rule 51(2) of the NGR provides examples of possible trigger events in an access arrangement. The AER may insist on the inclusion of trigger events and may specify the nature of the trigger events.[503]

12.6.2 Access arrangement proposal

NT Gas has proposed that the access arrangement will commence on the date on which the approval of the AER takes effect under r. 62 of the NGR. It has also proposed that it will submit revisions to this access arrangement on or before 1 January 2016 and that revisions to this access arrangement will commence on the later of 1 July 2016 and the date on which the AER's approval of the revisions takes effect under the NGR.[504]

12.6.3 AER's analysis and consideration

The AER does not accept section 1.5 of the proposed access arrangement which relates to the commencement of the access arrangement. The AER considers that this section incorrectly refers to r. 62 instead of r. 64 of the NGR. Rule 62 of the NGR sets out the obligations of the AER in making a final decision. In contrast, r. 64 of the NGR sets out the AER's power to make or revise the access arrangement on refusing to approve an access arrangement proposal. This includes r. 64(6) of the NGR which sets out the date on which an access arrangement or the revisions to which the decision relates takes effect. The AER requires NT Gas to amend section 1.5 of the proposed access arrangement accordingly.

Also the AER does not accept section 1.6 of the proposed access arrangement which relates to revisions to the access arrangement for a number of reasons. Firstly, the proposed review submission date of 1 January 2016 is after the date indicated by the general rule under r. 50(1) of the NGR, which is that the review submission date will fall four years after the commencement of the access arrangement. The AER considers that the proposed review submission date allows too little time for the AER to make a decision on the proposed access arrangement revisions, and would compromise the AER's ability to make a decision that is consistent with the national gas objective.[505] The AER considers that 1 July 2015 which is four years from the

499 NGR, r. 50(1).

500 NGR, r. 50(2).

501 NGR, r. 50(4)

502 NGR, r. 51(1).

503 NGR, r. 51(3).

504 NT Gas, *Access arrangement*, December 2010, p. 4.

505 NGL, s. 23.

commencement of the access arrangement (in the event that the access arrangement is approved on 1 July 2011) is a more appropriate review submission date. On this basis the AER does not approve the proposed review submission date.

Secondly, the AER considers that the last paragraph in section 1.6 of NT Gas's proposed access arrangement incorrectly refers to a service provider being able to propose revisions to its access arrangement at any time under r. 65 of the NGR and that "such revisions will commence in accordance with the National Gas Rules." Rule 65 of the NGR relates to an application to vary an access arrangement and the AER's consideration of such an application. Under this rule the AER can only approve a variation without consultation if it considers that the variation to the access arrangement is non-material. If the AER considers the proposed variation material, under r. 66(3) of the NGR such a proposal must be dealt with as a full access arrangement proposal (or limited access arrangement proposal in the case of a light regulation pipeline). Rule 66 of the NGR therefore does not allow the AER to approve a material variation to an access arrangement other than under Division 8 of the NGR.

The AER therefore considers that the last paragraph in section 1.6 of the proposed access arrangement does not accurately reflect r 65 of the NGR. In particular the AER notes that any requested variation must be considered by the AER and it is a question for the AER as to whether any non-material variations will commence. In the case of material variations, these will be dealt with as a full access arrangement proposal. On this basis the AER proposes not to approve this paragraph.

In relation to a revision of an access arrangement, a review submission date can be brought forward if the access arrangement provides for a trigger event and the trigger event occurs.[506] Unlike the earlier access arrangement which contained a trigger event mechanism, NT Gas has not proposed such a mechanism in its proposed access arrangement.

12.6.4 Conclusion

The AER proposes not to approve section 1.5 of the proposed access arrangement which relates to the commencement of the access arrangement. The AER considers that this section refers to the wrong rule and should be amended accordingly.

Also the AER proposes not to accept section 1.6 of the proposed access arrangement which relates to the revisions of the access arrangement. The AER proposes not to accept NT Gas's proposed review submission date. The AER considers an amended date of 1 July 2015, or four years from the commencement of the access arrangement (in the event that this access arrangement is approved later than 1 July 2011), would better promote the national gas objective under s. 23 of the NGL.

Further the AER proposes not to accept the last paragraph of section 1.6. The AER considers that this paragraph should be deleted from the access arrangement as it contains several inaccuracies which are inconsistent with r. 51 and r. 65 of the NGR.

However, the AER accepts the review commencement date proposed by NT Gas in section 1.6 of the access arrangement.

506 NGR, r. 51.

12.6.5 Required amendments

Before the access arrangement proposal can be approved, NT Gas must make the following amendments.

Amendment 12.10: amend section 1.5 of the access arrangement proposal by replacing Rule 62 with Rule 64.

Amendment 12.11: amend the first paragraph of section 1.6 of the access arrangement proposal by replacing 1 January 2016 with 1 July 2015, or four years from the commencement date of this Access Arrangement, whichever is the later.

Amendment 12.12: amend section 1.6 of the access arrangement proposal by deleting the last paragraph beginning with “Service Provider may, at any other time…”

A. Detailed WACC issues

This appendix outlines the AER's consideration of detailed issues in relation to NT Gas's proposed rate of return, under the following general categories:

- Overall rate of return
- Equity beta
- Debt risk premium
- Market risk premium

This appendix should be read on conjunction with chapter 5.

A.1 Overall rate of return

A.1.1 Recent sale of regulated assets

The AER considers that recent sales of regulated assets can provide useful information regarding the extent to which the AER's weighted average cost of capital adequately compensates regulated service providers. The AER's consultant, Professor Kevin Davis stated:

> … if access prices are set using the correct cost of capital such that expected future net cash flows provide both the required return to capital and the full return of capital, the market value of equity plus debt will (at the start of the regulatory period) equal the book (regulatory) value of assets. With the regulatory period, the valuation may differ because of unanticipated changes in risk premia or cash flows. In principle, if market value exceeds book value, this suggests that the regulatory rate of return is above that required by investors, and the converse when book value exceeds market value.[507]

Professor Kevin Davis also stated various factors may cause market and book values to differ at the date of the regulatory determinations. For instance, the market value can exceed the book value as regulated entities may also be involved in other non-regulated activities (which are able to earn excess returns), AER's financial and operating structure maybe sub optimal and possible synergies associated with mergers. Professor Kevin Davis states that the book value may exceed the market value if regulatory risk is high.[508]

While other factors may be present, the AER does not consider that they fully explain the purchase price of regulated utilities being 30 per cent more than the regulated asset base.

One of the most recent sales of regulated assets was the Envestra purchase of Country Energy's NSW Gas Networks business. Information relating to this sale was contained in a market presentation released to the ASX on 26 October 2010 and is summarised as follows:

507 Kevin Davis, *Cost of Equities – A Report for the AER*, 16 January 2011, p. 7.

508 Kevin Davis, *Cost of Equities – A Report for the AER*, 16 January 2011, p. 7.

- purchase price of $107 million
- regulated assets represent 70 per cent of purchase price
- the RAB was $59.6 million as at 30 June 2010 and forecast to be $63.2 million at 30 June 2011.[509]

The purchase of Country Energy's NSW Gas Networks business was a public tender and it is therefore reasonable to assume the sale price represents an approximate of the true market value. In addition, Envestra had the advantage of knowing the outcome of the AER's final decision on the access arrangement for the covered pipeline, including the cost of capital and the cash flows associated with that rate of return. The premium paid by Envestra relative to Country Energy's RAB suggests that the AER's weighted average cost of capital does not under compensate the service provider. Envestra purchased Country Energy's regulated assets at approximately 26 per cent (19 per cent if the 2011 RAB forecast is used) above the RAB value.

The AER recognises that Envestra may justify the high purchase price due to potential synergistic gains. However, the AER does not consider the 26 per cent premium can be justified on these grounds alone. The AER considers that synergies can be primarily driven by a minimisation of operating expenditure[510] which is only 34 per cent of total building block revenue in Envestra's case. Even if Envestra was able to reduce Country Energy's operating expenditure by half (impossible scenario), this would not justify the 26 per cent premium paid.

As demonstrated in table A.1 below, all regulated firms have been purchased at RAB multiples of greater than one, with a RAB multiple of at least 1.2 times.

509 AER, *Final decision, Wagga natural gas distribution network 1 July 2010–30 June 2015*, March 2010, p. 5 and ASX, *Envestra company announcement*, 26 October 2010, viewed 27 January 2011 <http://www.asx.net.au/asxpdf/20101026/pdf/31tcv1nblp4xqc.pdf>

510 The benefit associated with minimising capital expenditure is limited as it only relates to the return on capital for difference between actual and forecast capital expenditure for the outstanding year of the access arrangement period. This being due to the fact that actual capital expenditure and not forecasted capital expenditure is used to determine the opening regulated asset base. Further, other synergistic gains exist, but they are small in magnitude.

Table A.1: RAB multiple for recent regulated asset sales

Date	Acquirer	Target	RAB multiple (times)
Dec 06	APA	DirectLink	1.45
Oct 06	APA	Allgas	1.64
Aug 06	APA	GasNet	2.19
Apr 06	Alinta	AGL Infrastructure assets	1.41 – 1.52
Mar 06	APA	Murraylink	1.47
Aug 04	DUET/Alinta/Alcoa	Dampier to Bunbury Natural Gas Pipeline	1.20
Aug 04	APA	Southern Cross Pipeline and Parmelia Gas	1.47
Apr 03	Alinta/AMP/Aquila	Alinta Gas Network	1.35
Apr 03	Alinta/AMP/Aquila	Multinet Gas	1.44
Apr 03	Alinta/AMP/Aquila	United Energy	1.52
Aug 02	CKI/HEH	Citipower	1.69
Oct 00	Consortium	ElectraNet	1.37
Sep 00	CKI/HEH	Powercor	1.71
Jun 00	Singapore Power	PowerNet	1.49
Dec 99	CKI/HEH	ETSA Utilities	1.26
Jul 99	CKI	19.97% of Envestra	1.49
Jun 99	GPU	GasNet	1.72
Mar 99	Envestra/Boral	Stratus Networks	1.99
Jan 99	Texas Utilities	Westar	1.86

Source: Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock & Brown Infrastructure*, 9 October 2009, p. 78 and Grant Samuel & Associates Pty Limited, *Independent Expert Report in relation to the Acquisition of the Alinta Assets*, 5 November 2007, p. 65.

Table A.2 presents analysis from Grant Samuel which shows listed infrastructure firms being traded at premiums significantly above regulated asset values.

Table A.2: RAB multiples of regulated assets using recent market data

Entity	Average RAB as at 30 June 2009	Average RAB as at 30 June 2010
SP AusNet	1.50	1.40
Spark	1.81	1.73
DUET	1.21	1.15
Envestra	1.28	1.21

Source: Grant Samuel & Associates Pty Limited, *Financial Services Guide and Independent Expert Report in relation to the Recapitalisation and Restructure of Babcock & Brown Infrastructure*, 9 October 2009, p. 77. Based on share prices at 29 September 2009 and average nominal RAB for relevant year. RAB is based on the respective regulatory determinations except for DUET which allows for the $908 million expenditure on the Stage 5A and 5B expansion of the Dampier to Bunbury Natural Gas Pipeline.

Further, the AER considers the broker reports provided by Envestra also support the proposition that regulated utilities trade and are acquired at RAB multiples in excess of one.

A.1.2 Cost of equity vs. cost of debt

Contrary to the Synergies proposal, the AER does not consider that the difference between the estimate return on debt and equity should be at least around 4.5 per cent.[511]

There does not appear to be any a priori reason to expect to see a constant difference between the cost of debt and equity. This should be evident given the recent and significant impact of the GFC which predominantly affected debt markets. This has been reflected in the higher debt margins set by the AER during and since this time. An alternative conclusion from the information presented by Synergies and NT Gas is that the cost of debt set by the AER may be too high.

The AER has also identified more specific issues with Synergies' analysis. Synergies' estimated "required" difference between the return on equity and debt (at least 4.5 per cent) is a mid point of:[512]

- the average difference between the return on equity (14.8 per cent, based on the All Ordinaries Accumulation index) and debt (8.73 per cent, based on the UBS Australian Composition index) from 1990 to 2007, which was 6.07 per cent[513]
- the average difference between the return on equity (11.58 per cent, based on the All Ordinaries Accumulation index) and debt (8.73 per cent, based on the UBS

511 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 67–68.

512 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 67–68.

513 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 67–68.

Australian Composition index) “during a period that includes the effects of the current global financial crisis”, which was 2.85 per cent[514]

The 4.5 per cent difference is an overstatement with respect to the benchmark service provider as:

- the return on equity is based on the All Ordinaries Accumulation index, which has a beta of one and so should be adjusted to reflect a beta of 0.8, which the AER considers appropriate for a benchmark service provider. Such an adjustment would decrease the “required” 4.5 per cent difference between cost of equity and debt to 3.3 per cent

- the return on debt is based on the UBS Australian Composite Index, which is likely to be of a higher credit grade than BBB+ which the AER has determined reflects the rating of a benchmark service provider. Hence the return on debt should be increased to reflect a BBB+ credit rating which will decrease the 4.5 per cent further.

Further, the difference between NT Gas’s proposed cost of equity and debt is only 0.93 per cent.[515] As a result, the AER considers that NT Gas itself the does not consider the required difference between the cots of equity and debt must be at least 4.5 per cent.

NT Gas submitted that the return on debt is set based on prevailing market rates at the time of the regulatory reset, whereas two of the main components of the return on equity, being beta and the MRP, are assumed to be more stable through time and hence to be based on long-term averages.[516] As a result, NT Gas considers the recent regulated return on equity will provide equity investors with inadequate compensation for the risks they bear in the market environment that is expected to prevail over the course of the regulatory control period.[517] The AER does not agree with this proposition. Historical data is only used to the extent that it is reflective of (or informs the decision on the best estimate for) an expected rate of return on an ex ante basis. Both the cost of equity and cost of debt adopted by the AER in its allowed WACC are the best estimates of market returns expected over the access arrangement period. The following sections of this chapter set out reasons for rejecting NT Gas’s proposed parameters (where relevant) and the AER’s best estimates (and underlying methodologies).

A.1.3 Modigliani and Miller theorem

Synergies’ stated that the Modigliani and Miller approach, can be used to determine the optimal capital structure (trade-off between tax deductibility and bankruptcy costs) and explain the relationship between the cost of equity and cost of debt.

514 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 67–68.

515 NT Gas, *Access arrangement submission*, December 2010, p. 115; NT Gas, *Access arrangement information*, December 2010, p. 24.

516 NT Gas, *Access arrangement submission*, December 2010, pp. 102–103.

517 NT Gas, *Access arrangement submission*, December 2010, p. 102.

Professor Kevin Davis and Associate Professor Handley both caution the use of the Modigliani and Miller theorem to imply a relationship between the cost of debt and equity.[518] Handley considers the Modigliani and Miller theorem in the presence of risky debt is based on the assumption that equity and debt are priced in the (same) integrated market, rather than being priced in (separate) segmented markets. Handley states that when this assumption is assumed an exact relationship between the firm's cost of debt and equity can be established. However, when this relationship is violated this could imply that equity and debt is priced in:

- an integrated market and the equity risk premium is too low/high
- an integrated market and the debt risk premium is too low/high
- in segmented markets and so the Modigliani and Miller theorem cannot be used to infer that the equity is mispriced relative to the debt.[519]

The Modigliani and Miller proposition 2 can be used to demonstrate that the AER's WACC does not under compensate NT Gas. According to the Modigliani and Miller proposition 2, the WACC can be calculated as the return on equity of a firm with zero leverage. Removing the financial risk element from NT Gas's proposed equity beta of 1.0 results in an asset beta estimate of 0.40. Therefore, using the parameters in NT Gas's proposal, the return on equity on a zero leverage firm is:

$$r_e = r_f + \beta_a * (MRP)$$

$$r_e = 5.48 + 0.40 * (6.0)$$

$$r_e = r_0 = 7.88$$

The WACC as implied by the Modigliani and Miller proposition 2 using NT Gas's parameters is 7.88 per cent. This is in contrast to the AER's weighted average cost of capital in this draft decision, where the return on equity is calculated using the CAPM:

$$r_e = r_f + \beta_e * (MRP)$$

$$r_e = 5.53 + 0.8 * (6.0)$$

$$r_e = 10.33$$

$$r_o = r_e(\frac{E}{V}) + r_d(\frac{D}{V})$$

$$r_o(AER) = 10.33 * (0.4) + 9.32 * (0.6)$$

518 Kevin Davis, *Cost of Equities – A Report for the AER*, 16 January 2011, p. 19 and John Hanley, *Peer Review of Draft Report by Davis on the Cost of Equity*, 18 January 2011, pp. 9-10.

519 John Handley, *Peer Review of Draft Report by Davis on the Cost of Equity*, 18 January 2011, p. 9-10.

$$r_o(AER) = 9.72$$

As is evident, the AER weighted average cost of capital (9.72 per cent) is significantly higher than the WACC implied by Modigliani and Miller proposition 2 using NT Gas's parameters (7.88 per cent). The AER does not intend to set NT Gas's WACC based on Modigliani and Miller proposition 2, however notes that this analysis demonstrates that the AER's rate of return does not under compensate NT Gas.

A.2 Equity beta

The following section addresses issues raised by NT Gas in regards to the beta estimate.

Synergies submitted that paucity of relevant and reliable data has precluded it from being able to draw any robust conclusions regarding NT Gas's equity beta based on an updated empirical analysis.[520] However, Synergies empirical analysis can be relied on and be used to demonstrate that the AER's beta estimate of 0.8 is reasonable. As demonstrated in table A.3, all of the Australian equity beta estimates derived by Synergies for Australian utilities is below 0.8.

Table A.3: Synergies beta estimate

Firm	Asset beta	t-statistic	Equity beta
APA Group	0.29	4.23	0.73
Envestra	0.24	3.37	0.61

Source: Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline,* December 2010, p. 24 and AER analysis.

As discussed in the WACC review, the AER has been able to draw a conclusive robust beta estimate range from empirical analysis. Through the WACC review the AER took into consideration the following comparable businesses and estimated a forward looking beta estimate of 0.4 to 0.7:

- Alinta
- The APA Group
- Australian Gas Light
- The DUET Group
- Envestra
- GasNet Australia Group
- Hasting Diversified Utilities Fund

520 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, p. 4.

- SP AusNet, and
- Spark Infrastructure.

The AER also had regard to beta estimates from overseas jurisdictions, however placed limited weight on these and used the foreign estimates to confirm the upper bound of the domestic equity beta estimate.[521] To address the issue of short trading histories of Australian comparable companies, the AER estimated the beta using weekly observations (as opposed to monthly observations).[522]

Synergies submitted that asset stranding risk is a systematic risk driver in its beta analysis.[523] Synergies noted it was aware that asset stranding risk 'could' be a problem on the Amadeus gas pipeline, but was by its own admission not requested to—or in a position to—assess the materiality of that risk.[524] However, the AER considers asset stranding risk is not a systematic risk driver and does not justify a higher beta estimate for NT Gas.[525] The Allen Consulting Group (ACG) noted that under PWC's contractual arrangements with the Blacktip gas field and the Bonaparte Pipeline,[526] the AGP is a uniquely riskless asset with no foreseeable stranding risk.[527] The Northern Territory Treasury (NTT) similarly noted that PWC's dominant usage of the AGP leads to lower operating risks than those faced by other pipeline operators.[528] Consistent with the 2002 ACCC final decision[529], the AER considers that asset stranding risk is a business specific risk and should be accounted for by a cash flows adjustment (that is, accelerated depreciation), as opposed to an adjustment to the rate of return.

Further, the AER considers asset stranding risk has largely been eliminated in the 2001–2011 access arrangement period given the large return of capital in the earlier access arrangement period (through the accelerated depreciation allowance). [530] This has also been raised by the NTMEU which states that the accelerated depreciation of assets in the earlier access arrangement period has eliminated 'the bulk' of asset stranding risk.[531] The AER likewise does not consider the same uncertainty about usage of the pipeline exists in the current access arrangement review, as:

521 AER, *Final decision: WACC Review*, 1 May 2009, pp. 128–174.

522 AER, *Final decision: WACC Review*, 1 May 2009, pp. 128–174.

523 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline,* December 2010, p. 4.

524 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline,* December 2010, pp. 26–27.

525 The AER considers that the amount of gas reserves in the Amadeus Basin is unrelated to the overall market volatility.

526 A separate pipeline managed by APA, connecting the Blacktip gas fields to the AGP.

527 The Allen Consulting Group, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation in support of its submission to the AER's access review,* February 2011, p. 9.

528 NT Treasury, *Submission to the AER*, March 2011, p. 5.

529 ACCC, *Final decision*, December 2002, pp. 19–20.

530 ACCC, *Final decision*, December 2002, p. 68.

531 NTMEU, *Submission to the AER*, February 2011, p. 55.

- NT Gas has proposed a 'postage stamp' tariff, under which the same tariff would apply for users at the south of the pipeline sourcing gas from either the Blacktip fields (north) or the Amadeus Basin (south)[532]

- the majority of gas on the pipeline is now being sourced from the Blacktip fields, relieving concern about the heavily, but not completely depleted Amadeus Basin gas fields

- NT Gas expects to enter into a new contract with PWC for transport on the pipeline for the majority of pipeline capacity.[533]

Contrary to NT Gas's submission, the AER considers the Amadeus gas pipeline does have market power. The AER considers the only user does not have significant countervailing power. This user is unable to easily substitute away from the services offered by NT Gas as:

- the user takes and is expected to take delivery of gas across the entire pipeline, making bypass unlikely, and therefore has no feasible alternative sources of gas

- a large cost would be incurred by the user to substitute away from gas as a fuel source for electricity generation.

ACG submitted that an equity beta of 0.5 was appropriate for NT Gas, but note that there is an amount of arbitrariness arising from any point estimate of an asset's equity beta, particularly a quantitative assessment. This being the case, ACG submitted that the unique 'risklessness' of the AGP was strongly persuasive for informing such an estimate.[534]

Synergies also suggested that betas are mean reverting and over time, all betas of all firms will gradually move towards the equity beta of the market which is one.[535] As discussed in the WACC review, the AER considers that adjusting the beta for mean reversion to one (Blume adjustment and Vasicek adjustment) is not appropriate.[536] For instance, the Blume adjustment considers a firm becomes more diversified over time and therefore its beta approaches unity over time. However, the AER considers in a regulatory setting, the beta is determined on pure play basis and therefore the beta can not be estimated on a diversified entity. Further, in a regulatory setting the Blume adjustment is not an appropriate method to address imprecision of beta estimates.[537] The AER considers that an adjustment for mean reversion to one is likely to introduce an upward bias in the beta estimate. As outlined in the WACC review, the issue of precision can be better addressed through other methods which are unlikely to introduce a bias.[538]

532 NT Gas, *Access arrangement information*, December 2010, p. 29.

533 NT Gas, *Access arrangement submission*, December 2010, p. 10.

534 ACG, *Amadeus Gas Pipeline—Estimation of WACC*, February 2011, p. 15.

535 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 20–21.

536 AER, *Final decision: WACC Review*, 1 May 2009, p. 293.

537 AER, *Final decision: WACC Review*, 1 May 2009, p. 298.

538 AER, *Final decision: WACC Review*, 1 May 2009, p. 307.

A.3 Debt risk premium

The AER considers that the DRP should be based on an Australian corporate bond issuance with a term to maturity of ten years and a BBB+ credit rating. The ten year benchmark reflects consistency with the term of the risk free rate, while the BBB+ credit rating reflects what the AER determined during the WACC review following consideration of comparable energy businesses.[539]

NT Gas's regulatory proposal did not explicitly state the benchmark characteristics on which to base estimates of the DRP under the NGR.[540] Implicit in NT Gas's proposal, however, is that the DRP should reflect debt issued for a period of ten years, with a BBB+ credit rating.

The methodology proposed by NT Gas for estimating the DRP relied entirely on Bloomberg's five and seven year, BBB rated fair value yields, which were extrapolated linearly to determine a ten year estimate.[541] Based on a 20 day averaging period ending 30 November 2010, this approach provided a debt margin of 546 basis points above the risk free rate.

The AER considers that the DRP implied by Bloomberg's current fair value estimates, and proposed by NT Gas, is excessive, and not commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.[542] Further, the AER considers that the proposed debt margin is not consistent with section 24 of the NGL, in so much as the estimate of the benchmark cost of debt has insufficient regard to:

- the regulatory and commercial risks involved in providing the reference service (section 24(5))
- the economic costs and risks of the potential for under and over investment (section 24(6)).

The AER has previously expressed its concerns in placing full reliance on Bloomberg's fair value estimates.[543] Accordingly, the AER has examined alternative sources of information for estimating the DRP. In particular, the AER has considered the relevance of the ten year, BBB rated bond issued by the APA Group, the two BBB rated Sydney Airport floating rate bonds maturing in 2021 and 2022, the eight year, BBB rated Brisbane Airport bond, the ten year, A- rated SP AusNet and Stockland bonds, and the ten year, BBB+ rated Dalrymple Bay Coal Terminal (DBCT) bond as possible sources of information when setting the benchmark cost of debt.

539 While the SORI has no status under the NGR, it was intended to provide guidance to the gas sector.

540 NGR, r. 87(2).

541 Bloomberg does not publish separate fair value estimates for BBB-, BBB and BBB+ rated debt. Instead, all BBB bonds are included in a single sample. References within this chapter to Bloomberg's BBB fair value estimates encompass all bonds with a credit rating of either BBB-, BBB or BBB+.

542 NGR, r. 87(1).

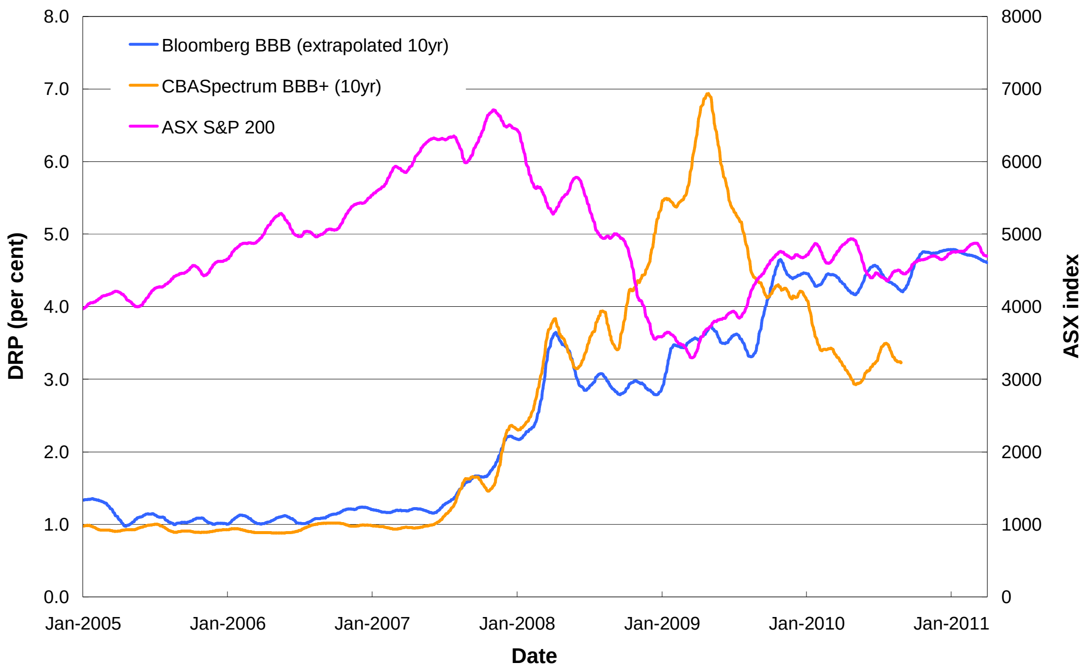
543 AER, *Draft decision–APT Allgas*, February 2011, p. 62.

A.3.1 Bloomberg

The AER has considered that Bloomberg's fair value estimates provided one independent and potential source of yield information on corporate bonds with a BBB+ credit rating and maturities up to seven years.[544] However, CBASpectrum's decision to cease publication of its fair value yield curves has given the AER cause to question the reliability of Bloomberg's estimates as the only source of information when setting the DRP, particularly given that both Bloomberg's and CBASpectrum's estimates rely on similar input data.

In exploring the performance of Bloomberg's estimates, the AER has compared them to the CBASpectrum yield curve and the value of the Standard and Poor's ASX 200—a broad based Australian share market index. These data are illustrated in figure A.1.

Figure A.1 Changes in debt risk premia in comparison to the ASX S&P 200—20 day moving average



Source: Bloomberg, CBASpectrum, RBA, AER analysis.

In viewing this figure, one should generally observe the DRP moving inversely to returns in the equity market. That is, during a bull market when equity returns are strong, the risk of default on debt should be comparatively low. Conversely, as the equity market falls, and the risk of default across the market increases, the debt risk premium demanded by investors should logically increase.[545]

While both the CBASpectrum and Bloomberg series increased in line with deteriorating equity market returns, Bloomberg’s spreads continued to increase with improving conditions in the equity market (implying increasing default risk). Indeed, the Bloomberg DRP was actually higher in December 2010 than at any time in recent

544 AER, *Final decision–Victorian electricity distribution network service providers, distribution determination 2011–2015*, October 2010, pp. 505–506.

545 In practice, the interaction between debt and equity markets is more complicated than this, but generally, heightened financial risk translates to lower share prices and a higher DRP.

history, including periods spanning the GFC. This contrasts with the RBA's June 2010 bulletin.

Specifically, the RBA stated that as risk aversion increased during the financial crisis, spreads (above the CGS) for BBB rated corporate bonds widened to historical highs, peaking in March 2009.[546] Further, the RBA added that spreads across all bond classes have since narrowed, though remain above the unusually low levels observed prior to the financial crisis.[547] The NTT also supports this view, noting that credit markets have stabilised and risk spreads are now substantially lower than during the GFC.[548] Unlike Bloomberg, the CBASpectrum fair value yield curve gradually declined in accordance with improved equity market conditions.

The significant divergence of estimates derived from Bloomberg data and from CBASpectrum over the timeframe including and since the GFC is also difficult to explain. The AER considers it is likely, however, to relate to the different proprietary methods employed by the data service providers, the method of extrapolating Bloomberg estimates to a comparable ten year maturity, and the general paucity of lower rated, long dated bonds.

To some extent, the limited market data that has recently become available further suggests that Bloomberg's series may not be representative of bond spreads beyond seven years. Specifically, in July 2010 the Australian Pipeline Trust—the financing arm for the APA Group—announced the issuance of a new ten year, BBB rated corporate bond (APT bond) with a yield to maturity well below that indicated by Bloomberg's fair value estimates. Similarly, both SP AusNet and the property firm Stockland recently issued ten year, A- rated bonds with current yields that are in excess of 200 basis points below the extrapolated Bloomberg fair value curve. Brisbane Airport also issued, in March 2011, eight year, BBB rated corporate bonds whereby investor interest was double that of the level finally issued.[549] Finally, reported yields for the BBB rated, Sydney Airport floating rate notes maturing in 2021 and 2022, are currently between 80 and 100 basis points below Bloomberg's BBB rated fair value estimates.

The paucity of corporate bonds currently trading in the market with maturities greater than five years and credit ratings at or close to BBB+ has been acknowledged by both NT Gas and the Tribunal.[550] For the indicative averaging period for this draft decision, the AER has compared all bonds with these characteristics, as reported on UBS and Bloomberg. These bonds are shown in figure A.2, along with Bloomberg's fair value estimates for five and seven years, and an extrapolation to ten years (using the AER's extrapolation method, discussed below).

546 The AER acknowledges that the RBA data refers to corporate bonds with maturities between one and five years. Though this differs from the AER's benchmark characteristics, the AER considers that relationship between risk aversion and debt margins holds equally for longer rated bonds.

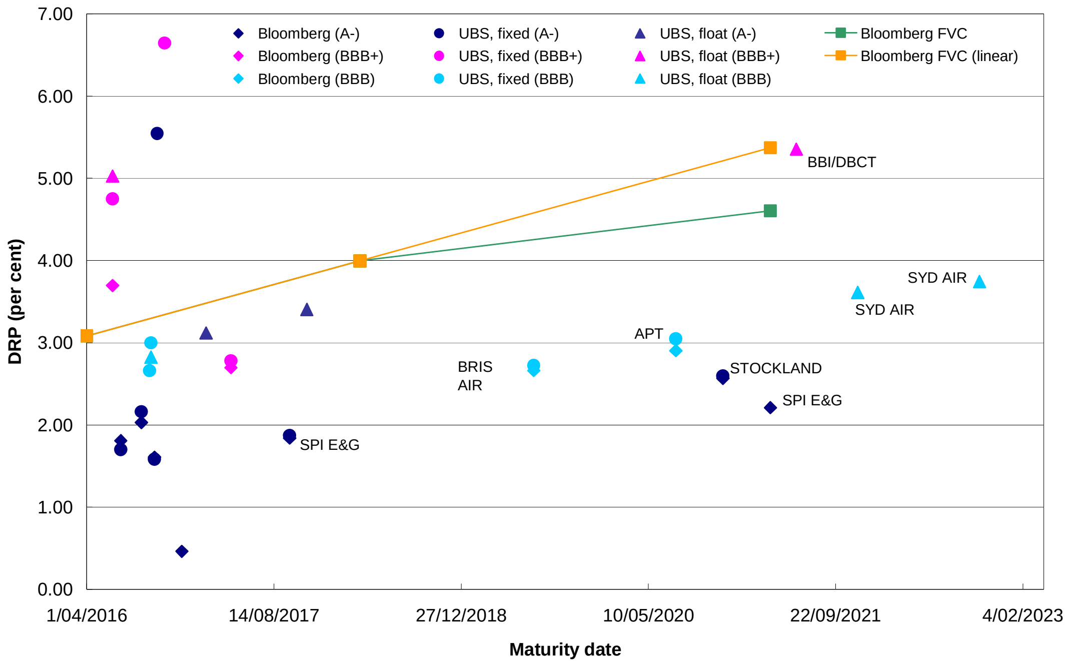
547 RBA, *Bulletin: June quarter 2010*, June 2010, pp. 58–59.

548 NT Treasury, *Submission to the AER*, March 2011, p. 5.

549 Brisbane Airport media release, *AUD$600 million debt successfully raised for BAC*, 23 March 2011.

550 NT Gas, *Access arrangement submission*, December 2010, p. 104; Australian Competition Tribunal, *Application by ActewAGL Distribution [2010] ACompT4*, 17 September 2010, paragraph 75, 77.

Figure A.2 Australian corporate bonds with maturities greater than five years and credit ratings ranging from BBB to A-



Source: Bloomberg, UBS, AER analysis.

Of the bonds plotted in this figure, the seven of immediate interest are the APT, Brisbane Airport, Sydney Airport (two), SP AusNet, Stockland and DBCT bonds, which are considered in turn below.

A.3.2 APA Group bond

For the indicative averaging period ending 1 April 2011, the annualised yields on the APT bond are 8.43 per cent and 8.58 per cent, as provided by Bloomberg and UBS respectively. The AER considers that these yields are likely to provide a close match to those of the benchmark corporate bond.[551] Specifically, the AER considers that the APT bond—with a BBB credit rating and ten year term to maturity—closely resembles the characteristics relevant to the benchmark corporate bond adopted by the AER in both electricity and gas determinations. To the extent that credit ratings reflect the risk of default, use of the APT bond would be expected to over compensate NT Gas with respect to the BBB+ rated benchmark cost of debt. This was also suggested by the NTMEU.[552]

However, credit ratings are not a perfect indicator of the risks involved in investing in the provision of reference services. As noted by Standard and Poor's:

> …Standard & Poor’s ratings opinions are not intended as guarantees of credit quality or as exact measures of the probability that a particular issuer or particular debt issue will default. Instead, ratings express relative opinions about the creditworthiness of an issuer or credit quality of an individual debt issue, from strongest to weakest, within a universe of credit risk. The

551 AER, *Draft approach for measuring the debt risk premium*, September 2010, p. 3.

552 NTMEU, *Submission to the AER*, February 2011, p. 79–82.

> likelihood of default is the single most important factor in our assessment of creditworthiness.[553]

Investors use means in addition to credit ratings to determine the risks associated with investing in particular firms. Consequently it is common to observe different yields on bonds with the same credit rating. Again, Standard and Poor’s noted that:

> … while credit quality does indeed influence credit spreads or prices, so do many other factors, sometimes overwhelmingly. For instance, investors typically require additional yield or spread compensation to buy a bond if the issuer is smaller than others in the market. Similarly, if an issuer rarely comes to market, or if little published research or coverage exists on it, its bond spreads may be higher, all else being equal.
>
> … Another non-credit-related factor that can widen a bond spread reflects the cost of insufficient information.[554]

The fact that investors take into account information other than credit ratings when assessing the risk of default is supported by recent analysis prepared for the AER by Oakvale Capital. In particular, when explaining the divergence in yields on bonds with similar credit ratings, Oakvale suggested that factors such as industry (for example, infrastructure versus financial institution bonds) and liquidity are relevant.[555] Similarly, a report by Associate Professor John Handley stated that empirical evidence may suggest factors other than simply credit risk (as reflected in the assigned credit rating) are taken into account by the market in pricing bonds.[556]

Synergies also noted the importance of liquidity in pricing bonds. Specifically, Synergies stated that liquidity is a critical factor in establishing the extent to which the price of a debt instrument fully reflects current information.[557] In this regard, Synergies proposed that the APT bond is illiquid, and that its lack of turnover implied that the yields on the APT bond were not reflective of prevailing market conditions.[558]

Yield estimates for the APT bond, however, are published by two independent data providers—Bloomberg and UBS. Moreover, both yield estimates are consistent, differing by less than 15 basis points.

Estimates of the APT bond yield from Bloomberg reflect Bloomberg Evaluated Prices (BVAL). The AER considers that while BVAL may not be the most preferred measure of bond yields published by Bloomberg—notably, other Bloomberg prices such as Bloomberg Generic Prices and Bloomberg Composite Market Prices reflect prices contributed to Bloomberg, whereas BVAL are derived prices—they still reflect yields published by an independent and well respected data services provider based on

553 Standard and Poor's, *Guide to credit rating essentials*, 2010, p. 4.

554 Standard and Poor's, *The wishes of crowds: Do credit spreads measure credit risk?*, 2010, p. 3.

555 Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011, pp. 2–3.

556 John Handley, *Comments of the CEG Report: Estimating the 10 year BBB+ cost of debt*, 11 February 2011, p. 6.

557 Synergies Economic Consulting, *Estimating a WACC for the NT Gas Transmission Pipeline*, December 2010, pp. 39–42.

558 Synergies Economic Consulting, *Estimating a WACC for the NT Gas transmission pipeline*, December 2010, p. 42.

prevailing market conditions.[559] Accordingly, the AER considers that in the current circumstances, Bloomberg's BVAL represent a reasonable estimate of the expected yields on the APT bond.

Similarly, the AER regards UBS as an independent and well respected data services provider, and considers that in the current circumstances its published yields provide reasonable estimates for the APT bond.

In regard to factors other than those reflected in credit ratings, the AER considers the factors specific to regulated energy networks affecting the APT bond to be relevant considerations in setting the benchmark cost of debt. In particular, the default risk of the APA Group's operations reflect its large, fixed investments whose returns are set in part under the regimes administered by the AER under the NGR and NER. The key features of these regimes—in contrast to investment risks in unregulated sectors—include "locked in" asset values and periodic resets of prices with respect to updated sales forecasts. Hence, to the extent that investors consider industry specific characteristics in addition to the assigned credit rating, the yields on the APT bond should be given weight in determining a rate of return that is commensurate with the risks involved in providing reference services.

NT Gas also proposed that it would be difficult to replicate the terms of the APT bond, as evidenced by the bond being awarded the KangaNews Australian domestic corporate market deal of the year, and Finance Asia magazine's best local bond deal. NT Gas proposed, therefore, that the APT bond was not a suitable comparator for assessing the DRP.

The APT bond, however, was negotiated in the period directly following the GFC. NT Gas characterised this period as representing a "very uncertain environment for domestic corporate issuers".[560] Accordingly, to the extent that market conditions have subsequently improved—as evidenced previously in this section—the AER considers that the difficulties in replicating a similar deal are likely to be overstated. The recent issuance by SP AusNet of a ten year corporate bond—albeit, with a higher credit rating—supports this position. Similarly, the recent eight year, BBB rated bond issued by Brisbane Airport suggests that NT Gas's concerns are unfounded.

Synergies also criticised the AER for not scrutinising the APT bond with the same veracity as it did the DBCT bond, to determine whether it is unusual or an outlier for the purposes of setting the DRP. In particular, Synergies proposed that the illiquidity of the APT bond rendered it an unsuitable comparator to the benchmark corporate bond. Synergies and NT Gas stated that this bond is unusual on the basis that:

- its yields are significantly below those derived from the extrapolated Bloomberg fair value curve,
- it is not included by Bloomberg when deriving its fair value curve; and

559 Specifically, BVALs reflect end of day, mark to market prices, derived from a multi-dimensional pricing methodology that incorporates real-time market data and advanced algorithmic models.

560 NT Gas, *Access arrangement submission*, December 2010, p. 107.

- two finance magazines name this bond issue the "deal of 2010".[561]

The AER, however, sought but did not find any information regarding the APA Group that suggested the yields on the APT bond were unusually low with respect to its credit rating or other benchmark characteristics. Pertinently, if anything, illiquidity is likely to drive estimated yields higher.

Further, the AER does not consider that the exclusion of the APT bond from Bloomberg's seven year, BBB rated fair value estimates necessarily inferred any substantive issues with the APT bond yields. Notably, the maturity of this bond is around two years longer than the seven year, BBB rated fair value estimates published by Bloomberg. Additionally, the methodology used by Bloomberg to determine fair value estimates is proprietary, limiting the AER's ability to assess the reasonableness of the sample used. Had the APT bond been included in Bloomberg's sample, the AER expects that Bloomberg's fair value estimates would have been lower.

A.3.3 Brisbane Airport, Sydney Airport, SP AusNet and Stockland bonds

In March 2011, SP AusNet issued ten year, A- rated corporate bonds. In November 2010, Stockland issued bonds with an identical tenor and credit rating. Brisbane Airport also recently issued eight year, BBB rated corporate bonds, and reported yields for two BBB rated Sydney Airport floating rate notes (maturing in 2021 and 2022) are currently available.

The characteristics of all these bonds—that is, their tenor and credit rating—are comparable to the APT bond, as well as the AER's benchmark. Moreover, as SP AusNet owns and operates network gas and electricity assets, its operations resemble those of the AER's notional benchmark firm.

In contrast, however, the ownership structure of SP AusNet—specifically, its ownership by the Singaporean Government—differs markedly from the APA Group, and from the AER's benchmark firm. Additionally, the nature of Stockland's assets and the industry in which it operates clearly differ to that of NT Gas. Brisbane and Sydney Airport's operations also differ from the AER's benchmark firm, though still reflect characteristics of a monopoly infrastructure firm.

These issues notwithstanding, the AER considers that the yields on the Brisbane Airport, Sydney Airport, SP AusNet and Stockland bonds provide points of reference to assess the reasonableness of Bloomberg's BBB fair value estimates and also of the APT bond yield. In this regard, the AER considers that many factors are likely to contribute to the divergent bond yields. The magnitude of these differences, however, is considerable. These yield comparisons are discussed below:

A.3.3.1 Brisbane Airport bond

The yield on the Brisbane Airport bond is 194 basis points below the extrapolated ten year Bloomberg fair value estimate. The AER considers that this yield differential is likely to be substantially driven by the bonds lower tenor, and to a lesser extent, its

561 KangaNews, Volume 5, Issue 46, December 2010, p. 47; FinanceAsia, Achievement awards 2010, December 2010.

credit rating. That is, the Brisbane Airport bond has a remaining term to maturity of approximately eight years (as distinct from the extrapolated, ten year estimate for Bloomberg), and a credit rating of BBB (as distinct from the Bloomberg compilation of all BBB-, BBB and BBB+ rated bonds).

The small yield differential between the Brisbane Airport and APT bonds (24 basis points) is expected, given their identical credit ratings and minimal difference in remaining tenor.

A.3.3.2 Sydney Airport bonds

The yield on the two Sydney Airport floating rate notes, converted to fixed rate equivalents, are 86 and 99 basis points below the extrapolated ten year Bloomberg fair value estimates. Given the longer tenor—these bonds mature in November 2021 and October 2022—and BBB credit rating, these yield differentials suggest concerns with either the Sydney Airport bond yields, Bloomberg's BBB rated fair value estimates, or that factors other than tenor and credit ratings are evident. The empirical evidence, however (as highlighted throughout section A.3.3), supports the yields on the Sydney Airport debt are reasonable.

The higher yield of the Sydney Airport bonds in comparison to the APT bond (70 and 84 basis points) is expected, given the greater remaining term to maturity of the Sydney Airport bonds.

A.3.3.3 Stockland bond

The remaining term to maturity for the Stockland bond closely matches the ten year term of the extrapolated Bloomberg estimates. Accordingly, the yield differential between the Stockland and Bloomberg estimates—204 basis points—is likely to be driven, primarily, by the difference in credit ratings. The lower yield on the Stockland bond is therefore expected. The magnitude of this difference, however, is considerable, indicating that other factors may be evident.

In regard to the APT bond, the yield on the Stockland issuance is 34 basis points below the APT bond yield. This divergence is reasonably expected given the counterbalancing effects of Stockland's slightly longer tenor but higher credit rating.

A.3.3.4 SP AusNet bond

The tenor of the SP AusNet bond is identical to the extrapolated Bloomberg fair value estimate. Accordingly, similar to the Stockland issuance, the difference between the yield on the SP AusNet bond and Bloomberg's fair value estimate—239 basis points—is likely to reflect the credit rating differential. The size of this difference, however, indicates that other factors are likely to be relevant.

The offsetting differences in tenor and credit ratings are likely to be key drivers of the yield differential (70 basis points) between the SP AusNet and APT bonds.

Overall, while the APA Group, Brisbane Airport, SP AusNet, Stockland and Sydney Airport bonds provide only six points of reference, they all consistently indicate that the extrapolated Bloomberg fair values may not be representative of longer dated, low rated bonds. Where NT Gas's method of extrapolation is applied, these differences are greater still.

Additionally, the observed yields of the Brisbane Airport, SP AusNet, Stockland and Sydney Airport bonds support the reasonableness of the observed yields on the APA Group bond.

A.3.4 Dalrymple Bay Coal Terminal (DBCT) bond

The characteristics of the DBCT bond maturing in 2021 match the benchmark ten year, BBB+ corporate bond. The AER, however, has previously expressed concerns over the reliability of this bond in comparative analysis.[562] Specifically, Bloomberg has intermittently published observations for the DBCT bonds in the past and they have been previously excluded from Bloomberg's fair value estimates given divergent data feeds.[563]

Further, while the voluntary trading suspension and subsequent market recapitalisation of BBI occurred in the past, market perceptions of the BBI/DBCT bonds may have shifted, despite the official credit rating assigned by Standard and Poor's remaining unchanged.[564] This consideration was supported by Oakvale Capital, who noted that for the period between April and May 2010, the uncertainty surrounding the issuer and the future status of the issue were likely to have been key contributors to the higher yield on the DBCT bond.[565] To the extent that these factors persist—and the large spread on the DBCT bond (around 500 basis points) compared to the smaller spreads on the APT, Brisbane Airport, Sydney Airport, SP AusNet and Stockland bonds supports this—the AER considers that they limit the reliability the DBCT bond for the purpose of assessing the benchmark cost of debt.

A.3.5 AER's method for setting the DRP

The lack of corporate bonds with BBB+ ratings and maturities of ten years makes it difficult to reliably ascertain the appropriate benchmark cost of debt. For the reasons outlined above, the AER considers there is a positive case for placing greater reliance on the APT bond in setting the DRP, particularly as the reasonableness of the spreads on this bond are now corroborated by the issuance of the Brisbane Airport, Sydney Airport, SP AusNet and Stockland bonds. In recognising the risks in setting a DRP on such limited information, the AER has adopted a cautious approach for the purposes of this decision and considered equally the spreads of the extrapolated ten year, BBB fair value derived from Bloomberg and of the APT bond when setting the DRP.[566]

NT Gas, however, stated that because the APT bond was issued by NT Gas's majority owner—the APA Group—references to this bond effectively reference NT Gas's actual cost of funds. NT Gas proposed, therefore, that reliance on the APT bond

562 AER, *Final decision*, October 2010, pp. 505–506.

563 PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, pp. 8–10.

564 Application by ActewAGL Distribution [2010] ACompT4, p. 22, paragraph 70.

565 Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011, pp. 20–22.

566 The AER notes that for the indicative averaging period—the 20 trading days ending 1 April 2011—the sample of bonds used to determine Bloomberg's BBB fair value estimates did not include the APT bond. The AER is uncertain as to why Bloomberg did not include this bond—noting that Bloomberg's methods are proprietary and not available for assessment by the AER—though does not consider that this materially impacts the use of the APT bond in assessing the benchmark cost of debt.

would limit their incentive to outperform the benchmark, as any benefits that would have otherwise accrued to the firm from adopting a particularly efficient financing strategy would be removed.[567]

The benchmark cost of debt set by the AER, however, does not adopt the yield on the APT bond. That is, the AER's benchmark cost of debt also gives weight to Bloomberg's fair value yields. Additionally, the APT bond only represents a limited proportion—approximately 9.50 per cent—of the actual funding costs of the APA Group, and subsequently, an even lower percentage of NT Gas's funding costs.[568] For these reasons, the AER considers that the use of the APT bond in determining the benchmark cost of debt does not materially reduce the incentive for NT Gas to source efficient financing strategies.

A.3.5.1 Extrapolation method

Since Bloomberg only publishes BBB fair value estimates to seven years, the AER and service providers have been required to extrapolate this curve to a ten year tenor for the purposes of setting the DRP. The AER has most recently considered that in lieu of Bloomberg publishing a ten year, BBB rated fair value estimate, the spread on Bloomberg's AAA rated estimates from seven to ten years should be added to Bloomberg's seven year, BBB rated fair value curve.[569] The AER considers that this extrapolation approach provides a better estimate of the ten year, BBB rated yields than an approach based on linear extrapolation, as proposed by NT Gas.

Specifically, the AER has previously demonstrated that a linear extrapolation of Bloomberg's BBB curve (using the change in spread between the five and seven year estimates, and projecting this to ten years) overcompensates network service providers, both on theoretical grounds (given that yield curves are not linear) and with respect to testing against earlier reported observations of Bloomberg's ten year BBB fair value estimates.[570] The ACG report supports this view:

> The standard methodology of linear extrapolation of Bloomberg corporate bond data has become increasingly unreliable as the source of longer maturity corporate bonds has gradually disappeared … When a higher maturity is sought to be estimated using bonds of lower maturity, linear extrapolation (as opposed to nonlinear extrapolation) becomes increasingly inaccurate, leading to over-estimates.[571]

In regard to the alternative extrapolation methods tested by the AER, these tests compared the absolute and squared differences from Bloomberg's ten year, BBB rated fair value estimates. The AER found that the spread between Bloomberg's AAA rated, seven and ten year fair value curves provided a smaller mean squared difference compared to the linear extrapolation method proposed by NT Gas. This contrasts to

567 NT Gas, *Access arrangement submission*, December 2010, p. 107.

568 Based on the $300 million face value of the APT bond, and total borrowings of $3156.8 million (at 30 June 2010) as reported in the APA Group's 2010 financial statements.

569 AER, *Final decision*, October 2010, pp. 510–511.

570 Bloomberg last published ten year, BBB+ fair value estimates for the periods from December 2001 to March 2002, June 2003 to October 2004, and November 2005 to October 2007. AER, *Final decision*, October 2010, p. 490.

571 The Allen Consulting Group, *Amadeus Gas Pipeline – Estimation of WACC, Report for Power and Water Corporation in support of its submission to the AER's access review*, February 2011, p. 5.

the Synergies analysis, though Synergies did not compare extrapolation methods over the entire period for when Bloomberg last published ten year, BBB rated fair value estimates.[572] The AER considers it more appropriate to assess the entire period (from November 2005 to October 2007). Table A.4 provides these results.

Table A.4: Mean absolute and mean squared differences from Bloomberg's ten year, BBB rated fair value estimates

	Nov 2005–Oct 2007		June 2003–Oct 2004		Jan 2002 –Mar 2002	
Extrapolation method	**Squared difference**	**Absolute difference**	**Squared difference**	**Absolute difference**	**Squared difference**	**Absolute difference**
Bloomberg BBB (5 to 7 years, linear)	0.0124	0.0863	0.0895	0.2886	0.0529	0.1786
Bloomberg AAA (7 to 10 years)	0.0025	0.0400	0.0085	0.0670	0.0908	0.2870
Bloomberg IRS (7 to 10 years)	0.0048	0.0586	0.0095	0.0742	0.0558	0.2265

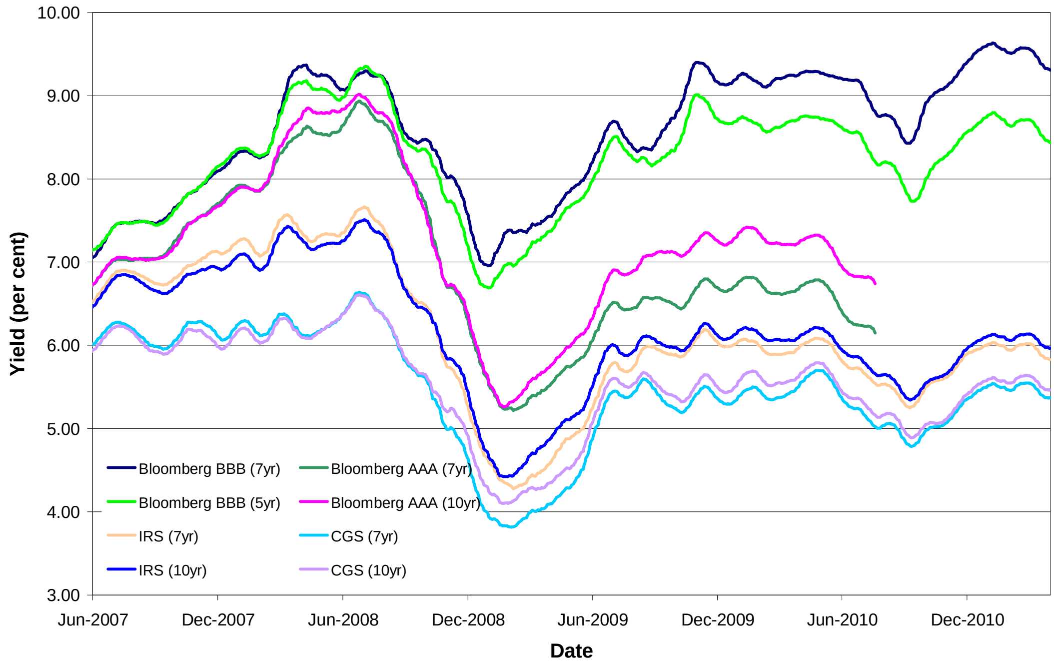
Source: Bloomberg, AER analysis.
Note: The AER also considered the spread between Commonwealth Government Securities, however, the results of this approach were demonstrated as being unreasonable in the Victorian electricity determination.

Further, a linear extrapolation of Bloomberg's seven year, BBB fair value curve results in a ten year yield estimate which is greater than the observed yield on the DBCT bond, for which the AER has previously expressed its doubts over.

Bloomberg, however, has not published seven or ten year, AAA fair value estimates since June 2010. Regardless, the AER considers that the most reasonable extrapolation approach is to add the spread on Bloomberg's AAA rated estimates from seven to ten years—as averaged over the last 20 trading days when these estimates were available, ending 22 June 2010—to the most recent estimates of Bloomberg's seven year, BBB rated fair value curve. This approach implicitly assumes that the spread between Bloomberg's seven and ten year, AAA fair value estimates has remained relatively constant over the period since June 2010. Figure A.3, below, supports this assumption.

572 Instead, Synergies only considered the first and last three month subsections for when Bloomberg last published ten year, BBB rated fair value estimates. Synergies Economic Consulting, *Estimating a WACC for the NT Gas transmission pipeline*, December 2010, pp. 47–50.

Figure A.3 Yield curve analysis—20 day moving averages—Bloomberg's AAA and BBB fair value estimates, interest rate swaps and Commonwealth government securities



Source: Bloomberg, AER analysis.

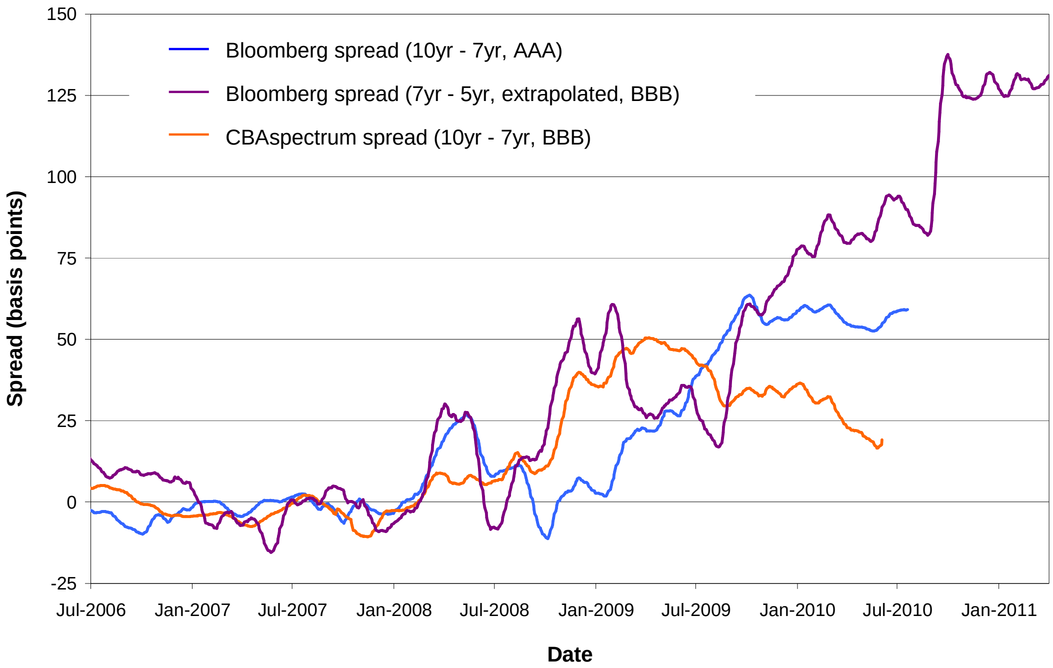
Notably, Bloomberg's seven year, BBB rated fair value curve has historically moved broadly consistent with Bloomberg's seven and ten year, AAA rated fair value curves. Further, these yield estimates have all moved consistently with the Australian dollar interest rate swaps and the Australian CGS. Accordingly, the AER considers it reasonable to infer that had Bloomberg continued to publish seven and ten year, AAA rated fair value curves, these curves would likely have continued to move in line with those examples provided above. In this regard, the AER considers that the spread between Bloomberg's seven and ten year, AAA rated curves reflects as reasonable an extrapolation method now as it did in June 2010.

The AER, however, has reservations, more generally, regarding the spreads on Bloomberg's AAA rated, seven and ten year fair value estimates. In particular, the spread between these two estimates in June 2010 was near historical highs, contrasting both improving conditions in debt markets and market commentary from the RBA.[573] The AER's reservations are even greater for the spread between Bloomberg's BBB rated, five and seven year fair value estimates, especially as this spread is magnified with NT Gas's proposed linear extrapolation approach. Notwithstanding these concerns, the AER is significantly constrained in regard to viable alternatives for extrapolating Bloomberg's seven year, BBB rated fair value estimates to a ten year term.[574] The corresponding spreads are shown below, in figure A.4.

573 RBA, *Bulletin: June quarter 2010*, June 2010, pp. 58–59.

574 The AER considers the proposal within the ACG report—to adjust the results of the linear extrapolation method downwards by 200 basis points. The also AER considers this approach to be arbitrary and lacking substantive theoretical analysis.

Figure A.4 Yield curve analysis—20 day moving averages—five to seven year, and seven to ten year spreads for Bloomberg and CBASpectrum



Source: Bloomberg, CBAspectrum, AER analysis.

For the reasons outlined above, the AER considers that NT Gas's extrapolation methodology does not provide for a rate of return on capital that is commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.[575] In contrast, the AER considers its extrapolation approach provides the best estimate possible in the circumstances.[576] Substitution of NT Gas's method with the AER's approach results in a reduction in the DRP of approximately 77 basis points (based on the indicative averaging period ending 1 April 2011).

A.3.6 Conclusion – debt risk premium

The AER acknowledges that Bloomberg is a well established and independent data service provider, and that Bloomberg's fair value yield curves have been relied on by the AER in previous regulatory determinations. However, given the concerns raised throughout this section, the AER does not consider that, in the current circumstances, sole reliance can be placed on Bloomberg's fair value estimates.

The AER has also considered other information which it considers relevant to the benchmark BBB+ rated, ten year bond yield. In particular, the AER considers that the credit rating, maturity and similarities between the operations of the APA Group and the AER's notional benchmark firm are likely to result in the spread on the APT bond being reflective of the default risk associated with investment in the provision of reference services. However, the AER has taken a cautious approach and does not consider that full reliance can be placed on any one individual bond. The AER's decision to consider equally the APT bond and Bloomberg has been substantiated to some extent by observations from the DBCT bond (which the AER has expressed

575 NGR, r. 87(1).

576 NGR, r. 74(2).

doubts over), and the Brisbane Airport, Sydney Airport, SP AusNet and Stockland bonds.

The AER therefore considers that an average of Bloomberg's ten year, BBB rated fair value curve and the APA Group bond represents the best DRP estimate possible in the circumstances of NT Gas.[577] Based on the indicative averaging period for this draft decision, these two information sources produce margins over the risk free rate of 4.60 per cent and 2.98 per cent. In exercising its discretion, the AER has given equal weight to both Bloomberg's fair value yield estimates, and the APA Group bond. This results in a DRP of 3.79 per cent over the indicative averaging period ending 1 April 2011.

A.4 Market risk premium

A.4.1 Time periods for historical excess returns

Table A.5: Historical excess returns estimated using geometric means and arithmetic means (assuming an imputation credit utilisation rate of 0.65) (%)

	Historical excess returns (geometric means)	Historical excess returns (arithmetic means)
1883–2010	4.9	6.3
1937–2010	4.1	6.1
1958–2010	4.1	6.6

Source: Handley, *An estimate of the historical equity risk premium for the period 1883 to 2010*, January 2011, p. 8.

The starting points for each sample period in table A.5 are consistent with those considered by the AER during the WACC review. The AER considered the sample periods noted above for the following reasons, which were mostly based on the findings of a study by Brailsford, Handley and Maheswaran:

- The period 1883 to 2010 provides a large sample, which incorporates many years of excess returns data as well as large negative and positive market events. However, for the period up to 1937 there is a relatively small sample of stocks available and periods of government stock price controls.[578]
- The period 1937 to 2010 provides a slightly smaller number of observations than the 1883 to 2010 period, but it incorporates a consistently larger sample of stocks and avoids the problems associated with data prior to 1937.
- The two time periods above both incorporate data from the Lamberton data series up to 1958, which is likely to overstate historical excess returns prior to 1958. The Lamberton data series uses an equal weighted rather than value weighted average of stock returns, which results in a bias towards high yielding small stocks. In

577 NGR, r. 74(2)(b).

578 Brailsford, Handley and Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and Finance, vol. 48, pp. 78–79.

addition to this, the Lamberton data series comprises dividend paying stocks only, which results in an overstatement of the market average. This is because not all stocks pay dividends. In estimating historical excess returns, Brailsford et. al. adjusted pre-1958 data by a factor of 0.75 and Associate Professor Handley incorporates this adjustment also. However, it is uncertain what the exact adjustment factor should be. Therefore, it is useful to consider estimates using data from 1958 onwards as well.[579]

- The period 1958 to 2010 provides a smaller number of observations, but it avoids the issues associated with data prior to 1958.

A.4.2 The difference between arithmetic and geometric means

Table A.5 outlines Associate Professor Handley's latest historical excess returns estimates calculated as arithmetic and geometric means. The difference between these estimates demonstrates the variability of excess returns over time.

Arithmetic means are more appropriate when observations are considered independent in a statistical sense. In contrast, geometric returns are more appropriate when observations are related to each other over time (for example, if yearly excess returns are the relevant observations, returns can be expected to accumulate over time). As long as returns vary over time a geometric mean will always be less than an arithmetic mean. The greater the volatility in returns, the greater the difference between arithmetic and geometric means.

The difference between arithmetic and geometric means becomes apparent through a simple example. Suppose an index starts at 100, falls to 80 and then increases again to 100, the arithmetic mean return is 2.5 per cent.[580] The geometric mean return is zero.[581] The arithmetic mean return contemplates two possible scenarios—the index falls by 20 per cent or the index rises by 25 per cent. The geometric mean return contemplates the accumulated return over two years (if the investor had a two year investment horizon, the return over that horizon would be zero). It is clear that over a two year investment horizon, the arithmetic mean would overstate the return. However, if the investment horizon was one year, the arithmetic return would be the correct estimate. To form an expectation about one year in the future based on historical evidence we would look at what is possible over a one year horizon, which could be either a loss of 20 per cent or a gain of 25 per cent. In this case, the geometric mean would be an underestimate of the forward looking return.

The historical excess returns used in Associate Professor Handley's estimates are calculated on a yearly basis.[582] Therefore, for a 10 year horizon the arithmetic mean of yearly excess returns in each of the sample periods (127 years, 73 years, and 52 years) will overestimate the historical return on a 10 year investment. In contrast, the geometric mean for each of the samples will underestimate the historical return on a

579 Officer and Bishop, *Comments on the AER draft distribution determination for Victorian electricity distribution network service providers*, July 2010, p. 21.Officer and Bishop appear to incorporate this adjustment in their long-term estimates.

580 A fall of 20 per cent plus a rise of 25 per cent, divided by 2.

581 The square root of (1–0.20)*(1+0.25), minus 1.

582 Handley, *An estimate of the historical equity risk premium for the period 1883 to 2010*, January 2011, pp. 3–4.

10 year investment because the data reflects a cumulative return over the entire sample period.

It may seem appropriate to estimate a 10 year return within each of the sample periods outlined above. However, without any overlap in yearly observations this would significantly reduce the number of observations. The number of observations within each of the samples considered would fall from 127, 73 and 52 yearly observations to approximately 13, 7, and 5 observations.

Therefore, it is not easy to calculate excess returns over a 10 year investment horizon with the available data. Arithmetic means are generally used in estimating expected values and it is also likely that investors 'think' in terms of annual returns, which the AER noted in the WACC review final decision.[583] However, the issues outlined above suggest that the arithmetic mean of yearly excess returns is likely to overstate the excess return over a 10 year horizon.

In the WACC review, the AER noted that Blume, as well as Dimson, Marsh and Staunton have proposed methods that could be used to calculate an expected MRP using both arithmetic and geometric means.[584] The results from these weighted averages produce different results, which makes it harder to determine which form of adjustment is best. Rather than using a complex weighted average or an adjustment approach, which may not add a greater degree of precision to historical estimates, the AER considers that arithmetic averages should be interpreted with the understanding that they may overstate the expected forward looking 10 year MRP to some extent.

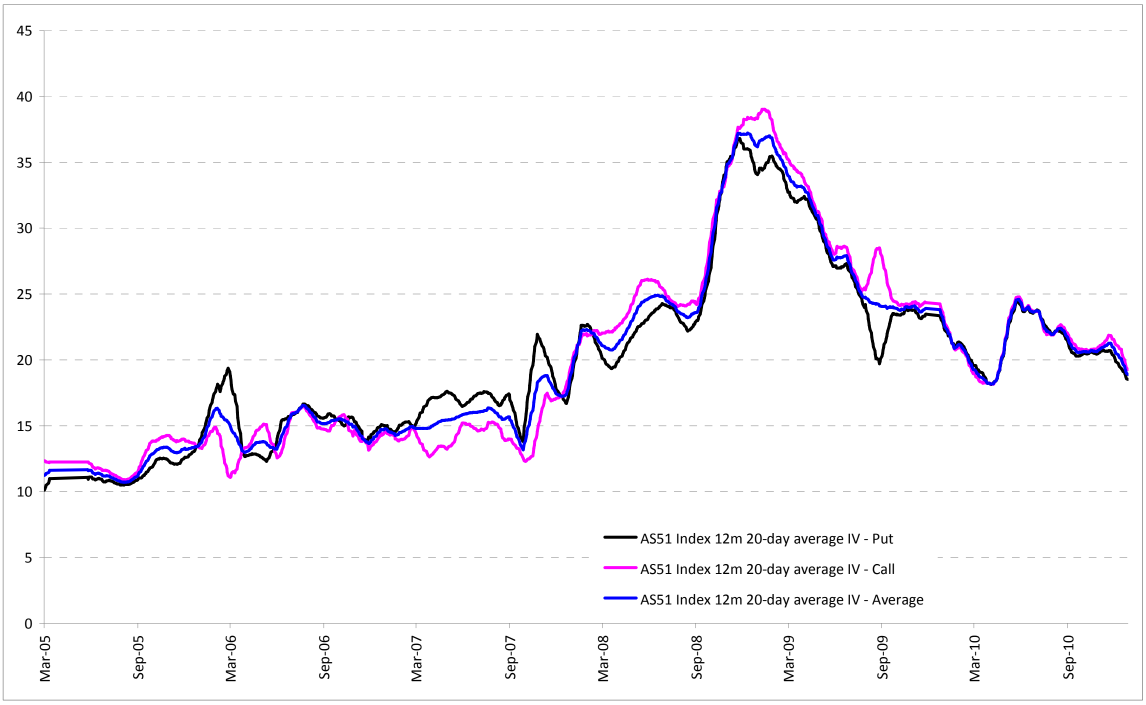
A.4.3 Implied volatility and Officer and Bishop's 'glide path' approach

The current level of volatility in the stock market can be estimated using the volatility implied by the Black-Scholes option pricing formula. However, implied volatility varies significantly and provides only a very short term view of market volatility at any point in time. This can be seen in figures A.5 and A.6.

583 AER, *WACC review final decision*, 1 May 2010, p. 199.

584 AER, *WACC review final decision*, 1 May 2010, pp. 198–199.

Figure A.5: Implied volatility from option prices as reported by Bloomberg



Source: Bloomberg, AER analysis.

Figure A.6: Implied volatility on S&P/ASX200 as reported by the ASX

Source: ASX, http://www.asx.com.au/products/indices/types/sp_asx200_vix_index.htm viewed 13 January 2011.

Officer and Bishop submitted that an MRP of 8 per cent is appropriate over a five year period to 2016 based on a 'glide path' approach:

- Officer and Bishop estimated the volatility implied from the Black-Scholes option-pricing formula for 12-month ASX200 index call options to be 11.9 per cent. This estimate assumed a market risk per unit of option implied volatility of 0.5. It is a 1-year estimate of the MRP.

- Officer and Bishop then estimated the geometric average MRP over five years assuming the MRP would revert from 11.9 per cent in 2011 to a long run estimate of 7 per cent within a five year period. [585]

Officer and Bishop implicitly assumed there was no structural break in the MRP as a result of the GFC because the MRP is assumed to revert to a long run MRP estimate of 7 per cent.[586] In a previous report, Officer and Bishop advocated using a long term estimate due to the variability in data on market returns.[587] However, Officer and Bishop still incorporate the short term 11.9 per cent option implied volatility into their estimate of the MRP, rather than simply advocating their long term MRP estimate of 7 per cent. Officer and Bishop have previously stated that due to abnormally high levels of volatility, it is appropriate to estimate the forward looking MRP using the current level of implied volatility and a ‘glide path approach’. Figures A.5 and A.6 show that implied volatility has dropped significantly since the onset of the GFC. It does not seem reasonable to continue to apply a ‘glide path’ approach rather than applying a long term historical estimate of the MRP.

The AER also has a number of concerns with the use of implied volatility in providing the best estimate of the MRP over a 10 year time horizon. Officer and Bishop’s 11.9 per cent estimate of the 1-year MRP relies on an assumption that the market risk per unit of option implied volatility is constant at 0.5. Officer and Bishop have previously claimed that this approach is justified based on empirical and theoretical support from a paper by Doran et al.[588] However, Doran et al found that short run volatility had a surprisingly small impact on the medium term MRP. Specifically, they found that short term volatility only has a 10 per cent weight in determining the medium term volatility and suggests ‘that investors focus more on long-term volatility and are relatively insensitive to short term volatility swings.’[589] Doran et al also found that their implied risk approach produced a negative implied equity risk premium from S&P 500 index option prices during periods of “irrational exuberance”.[590] Other research also suggests that option implied volatility is an unreliable estimator of the expected MRP.

585 Officer and Bishop, *Comments on the AER draft distribution determination for Victorian electricity distribution network service providers*, July 2010, p. 19.

586 The AER notes above that Officer and Bishop’s 7 per cent historical MRP estimate is an arithmetic average and is subject to the data issues related to long term historical MRP estimates outlined above.

587 Officer and Bishop, *Market risk premium*, A review paper, August 2008, pp. 36–37.

588 James Doran, Ehud Ronn and Robert Goldberg, *A simple model for time-varying expected returns on the S&P 500 index*, working paper, University of Texas, June 2005. See Officer and Bishop, Market risk premium, further comments, January 2009, pp. 7–8.

589 James Doran, Ehud Ronn and Robert Goldberg, *A simple model for time-varying expected returns on the S&P 500 index*, working paper, University of Texas, June 2005. See Officer and Bishop, Market risk premium, further comments, January 2009, p. 17.

590 James Doran, Ehud Ronn and Robert Goldberg, *A simple model for time-varying expected returns on the S&P 500 index*, working paper, University of Texas, June 2005, p. 19.

Santa-Clara and Yan studied the ex ante risk premiums implied from S&P 500 index option prices. Santa-Clara and Yan's research shows that option implied volatility is much higher than realised market risk. Santa-Clara and Yan stated:[591]

> …the average premium that compensates the investor for the risks implicit in option prices, 11.8%, is about 40% higher than the premium required compensating the same investor for the realised volatility in stock market returns, 6.8 per cent.

Chernov studied the role of risk premia in volatility forecasting and explained why at-the-money option implied volatility is a biased and inefficient forecast of future realised volatility.[592]

Based on the research from Doran et al, Santa-Clara and Yan, and Chernov, the AER considers that option implied volatility is too highly variable to be used as a basis for estimating the forward looking 10 year MRP.

Officer and Bishop's 'glide-path' approach incorporates a highly variable 1-year estimate of implied volatility and then combines it with a long term historical estimate of 7 per cent over a five year time horizon. As discussed in chapter 5 and outlined in figure 5.1, realised excess market returns fluctuate significantly between a positive and a negative MRP. It is quite possible that in one year realised excess market returns will be below their long term estimate of 7 per cent (or 6 per cent), but this is not considered in Officer and Bishop's analysis. All that is considered is a level of implied volatility measured as at July 2010, which trends downwards to a long term historical estimate. However, the realised MRP could be below long term estimates in some years (for example, below 6 per cent). Officer and Bishop do not take this into account in their 'glide path' analysis. The AER considers that the significant variability in the short term MRP derived from implied volatility measures makes such estimates an unreliable source of evidence when setting a MRP for a 10-year investment horizon.[593]

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591 Pedro Santa-Clara and Shu Yan, '*Crashes, volatility, and the equity premium lessons from S&P options,' Review of Economics and Statistics*, 92(2), May 2010, p. 450.

592 Mikhail Chernov, '*On the role of risk premia in volatility forecasting, Journal of Business and Economic Statistics*, October 2007, vol. 25, no. 4, pp. 411–426.

593 Officer and Bishop's approach also looks specifically at a five year, rather than a 10 year time horizon. Within the CAPM, the MRP is calculated as the expected return on the market portfolio minus the risk free rate. For the purposes of this access arrangement review the AER has used the yield on 10 year CGS as a proxy for the risk free rate. As a result the MRP needs to be estimated for a 10 year time horizon as well. Therefore, in addition to other problems with Officer and Bishop's 'glide-path' approach, Officer and Bishop consider a time horizon that is inconsistent with the assumed 10 year period for the risk free rate.

B Debt raising costs

Debt raising costs are transaction costs—such as legal fees, underwriting fees or credit rating fees—incurred as debt is raised or refinanced. The AER accepts NT Gas's proposal to determine debt raising costs using the AER's standard method.[594] The AER has updated the inputs to this model and determines a debt raising cost unit rate of 10.9 basis points per annum (bppa), which is applied to the benchmark debt component of the capital base to estimate the total allowance for debt raising costs for the access arrangement period. Although NT Gas proposed this allowance be rolled into the overall WACC, the AER implements a separate opex line item to preserve transparency.

B.1 Access arrangement proposal

NT Gas proposed to follow the AER's standard method for the determination of debt raising costs,[595] which is based on a 2004 report to the ACCC by the Allen Consulting Group (ACG).[596] NT Gas proposed a debt raising cost unit rate of 10.8 bppa,[597] which was based on the allowance set for Jemena Gas Networks in an earlier AER decision document.[598] This unit rate was then incorporated into the overall cost of debt used as an input to the WACC, such that NT Gas proposed to receive debt raising costs as an implicit component of its return on capital. NT Gas stated that this was the 'simplest and most transparent approach'.

B.2 AER considerations

The AER accepts NT Gas's proposal to use the AER standard method, but has reservations about the inclusion of debt raising costs as an implicit component of the return on capital. Although this practice was common amongst state regulators, it conflates two separate components of the building block model. Separating out the transaction costs of accessing capital from the return to capital providers preserves the distinction between these components of the model, and therefore is the most transparent option available. Further, discretely stating the debt raising cost allowance aids comparability across different regulatory decisions, and has been the practice of the AER in all decisions to date.

Table B.1 shows the build up of debt raising costs, after updating inputs to the model.

594 NT Gas, *Access arrangement submission*, December 2010, p. 115. This standard methodology, based on the 2004 ACG report, has been refined by the AER across previous regulatory decisions, and is explained in detail below.

595 AER, *Final decision, South Australia distribution determination 2010–11 to 2014–15*, May 2010, pp. 124–133, 371–384 appendix J; AER, *Final decision - appendices, Victorian electricity distribution network service providers, Distribution determination 2011–2015*, pp. 474–501, ppendix N.

596 ACG, *Debt and Equity Raising Transaction Costs, Final Report to the Australian Competition and Consumer Commission*, December 2004.

597 NT Gas, *Access arrangement submission*, December 2010, p. 115.

598 AER, *Final decision– JGN*, June 2010, p. 278.

Table B.1 Indicative direct debt raising costs

Fee	Explanation	1 Issue	2 Issues	3 Issues	4 Issues	5 Issues
Amount Raised	Multiples of median MTN ($250m)	$250m	$500m	$750m	$1000m	$1250m
1. Gross underwriting fee	Median gross underwriting spread, up front per issue, amortised	7.30	7.30	7.30	7.30	7.30
2. Legal and roadshow	$115K upfront per issue, amortised	0.75	0.75	0.75	0.75	0.75
3. Company credit rating	$50K per annum	2.00	1.00	0.67	0.50	0.40
4. Issue credit rating	4 basis points up front per issue, amortised	0.65	0.65	0.65	0.65	0.65
5. Registry fees	$3.5K per issue, per annum	0.14	0.14	0.14	0.14	0.14
6. Paying fees	$4/$1 million per annum	0.04	0.04	0.04	0.04	0.04
Total	**Basis points per annum**	**10.9**	**9.9**	**9.5**	**9.4**	**9.3**

Source: ACG, Bloomberg, AER analysis.

NT Gas has an opening capital base of $104 million, which leads to a notional debt component of $63 million at the assumed gearing ratio (60 per cent). This amount of debt requires one standard size ($250 million) bond issue. After adjusting for the indicative draft decision discount rate the appropriate unit rate estimate is 10.9 bppa.[599] This leads to the debt raising allowance set out in table B.2.

Table B.2 AER's conclusion on debt raising costs ($m, 2010–11)

Description	Unit rate	Form of allowance	2011–12	2012–13	2013–14	2014–15	2015–16	Total
NT Gas Proposal	10.8 bppa	Implicit in WACC	(no explicit allowance)					
AER draft decision	10.9 bppa	Opex line item	0.07	0.07	0.07	0.06	0.06	0.32

Source: NT Gas, *Access arrangement submission*, December 2010, p. 115; AER analysis.
Note: Numbers may not add due to rounding

B.3 AER conclusion

The AER approves the method proposed by NT Gas for determining the debt raising cost unit rate, but does not approve the form of this allowance (as an implicit

599 For the final decision, this unit rate will be updated in respect of the discount rate.

component of the WACC). The AER considers that a separate debt raising costs line item as shown in table B.2 is:

- consistent with the expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with r. 91 of the NGR
- arrived at on a reasonable basis and represent the best estimate possible in the circumstances, in accordance with r. 74 of the NGR.

The AER requires NT Gas to amend its debt raising costs as outlined in amendment B.1.

Amendment B.1: make all necessary amendments to the access arrangement proposal and access arrangement information in order to be consistent with table B.2

C Non-tariffs —Terms and conditions

<table>
<tr><th>Matter</th><th>Description of terms and conditions, submissions and AER’s consideration</th><th>Amendment required</th></tr>
<tr><td>Prudential requirements

clauses 1(a) and (b)</td><td>NT Gas proposed that it may require a User to provide financial security that is acceptable to NT Gas for the performance of the User’s obligation under the User’s transportation agreement. This may be required prior to the commencement of services or in certain other circumstances during the term of the agreement (clause 1(a)).

NT Gas has also proposed that it may refuse to provide or suspend the provision of services without liability in certain circumstances. This may be where the User has failed to pay any amounts due payable under its transportation agreement or where the User has failed to obtain and maintain any approvals required to meet its obligations under its agreement (clause 1(b)).

Santos and Magellan submitted the following in regards to clause 1 of NT Gas’s access arrangement:
▪ the right to call for security should be clearly defined
▪ the maximum amount of any security should be defined
▪ NT Gas should be required to act reasonably in requiring security
▪ the right to suspend should be clearly defined.

PWC submitted that clause 1 in its lack of specificity was “[o]ne sided and discretionary” and would “defeat the purpose of an access arrangement.” PWC also in its submission includes the following (“Actual contracting party has to be company of financial substance and technical capability otherwise additional security such as parent company guarantee to be provided”) which the AER understands to be a reference to clause 1.

The AER considers that clause 1 should clearly set out the scope of the prudential requirements with the requirement qualified to reflect that the security sought must be reasonably determined by the Service Provider. The AER considers that this would better reflect the description in clause 2.5(a)(iii) of the Access Arrangement proposal which states that the User “may be required to provide reasonable security in the form of a parent company guarantee or a bank guarantee or similar security…”. The AER accepts PWC’s submission that a parent company guarantee may be an appropriate form of security but considers that it is for the Servicer Provider to reasonably determine the form and the circumstances in which such a</td><td>Amend clause 1(a) as follows:

“(a) require the User to provide, prior to commencement of Services and thereafter as reasonably required, financial security in the form of a parent company guarantee, bank guarantee or similar security as reasonably determined by the Service Provider for the performance…”

Amendment to clause 1(b) as follows:

“where the User:
(i) fails to pay when due any amounts payable under the Transportation Agreement, excepting any contested amounts; or
(ii) fails to obtain and maintain any Approvals required to meets its obligations under the Transportation Agreement

subject to providing at least 7 days written notice to the User, refuse to provide or suspend the provision of Services, without liability to the User.”</td></tr>
</table>

	security would be reasonably required. This would effectively apply a similar approach to security as adopted in the previous Terms and Conditions applicable in the earlier access arrangement. Clause 1(a) should be amended accordingly. The AER considers that clause 1(b) is too broadly drafted in covering "certain circumstances" without specifying all such circumstances. The AER agrees with Santos and Magellan that the circumstances which trigger the right to suspend should be clearly defined. In addition, including a failure to pay any amounts due is too broad and should exclude any payments which are in dispute. The AER considers that this term is not reasonable to the extent that it is not appropriate to cease supply and remove liability in circumstances where a payment is contested. The AER further considers that clause 1(b) should include a requirement that at least 7 days written notice be provided to the User before Services are suspended. The AER considers that this would be more reasonable than ceasing supply without any notice to the User at all.	
Nominations clauses 2, 3, 4 and 5	In relation to Nominations, NT Gas has proposed a reduction in the time a User must give notification from at least 7 days before the beginning of each month to at least 3 days (**clause 2**). Clause 2 further provides that if a User does not provide a Nomination then its Nomination for each day it fails to provide notification will be zero GJ. The AER considers that clause 2 is acceptable. In **clause 3**, NT Gas has proposed a Nomination Deadline of 2.30pm where as 3pm was the previous deadline for variations for a particular day. PWC submitted that NT Gas should have a reasonable endeavours obligation to comply with nominations received later than 2.30pm on the day before. The AER considers that clause 3 is acceptable. As the purpose of revising the Nomination by the Nomination Deadline is to allow the User to make any required adjustments and allow NT Gas sufficient time to meet this request, it is appropriate that NT Gas be able to nominate a set time so as to ensure it can meet the revised Nomination. The AER further notes that no reasonable endeavours qualification attached to the obligation under the previous terms and conditions. **Clause 4** provides that NT Gas is not liable for providing to the User any service beyond a minimum obligation to provide services only once it has scheduled those services. The Service Provider is not obliged to schedule the services nominated by the User, but is required only to process the Nomination.	Amendments: Insert new clause 1 under the heading "Obligation to Transport": *"Subject to the terms of the Agreement, the Service Provider will receive gas from the Users at the Receipt Points and deliver gas at the Delivery Points."* Delete clause 4. Amend clause 5. *"The service provider will not be obliged to receive or deliver on any Day a quantity of gas in excess of the User's MDQ."* The word *"intended"* to be deleted from the definition of "Schedule".

	PWC submitted that NT Gas should be obliged to schedule the Nominations made up to the MDQ. In the absence of any justification that would warrant the inclusion of this clause, the AER considers that **clause 4** is not reasonable. The AER notes that the definition of "Schedule" is defined to mean "a determination…of the Service Provider's intended Schedules of receipt quantifies and delivery quantities of Gas on that Day under Transportation Agreements…" The AER considers that this implies that there is no obligation to provide the services of transport and delivery but only to make a determination of what NT Gas, intends to do. It appears to reflect an intention, rather than any actual obligation to provide the service. Accordingly, the AER considers that clause 4 should be deleted. The AER further considers that the definition of "schedule" should be amended to reflect more than an intention to schedule. In addition, the Terms and Conditions should be amended to expressly include a clause providing for the service provider's obligation to transport and deliver gas, as reflected in clause 3 of the Terms and Conditions in the earlier Access Arrangement. This should appear as the first clause of the Terms and Conditions under the heading "Obligation to Transport". The AER agrees with PWC that NT Gas should be obliged to schedule the Nominations up to the MDQ. Such an obligation would reflect the obligations in the previous Terms and Conditions (at clauses 11 and 12). The AER therefore considers that **clause 5** should be amended accordingly.	
Scheduling clauses 6, 7, 8(not used), 9 and 10	NT Gas proposed that under **clause 6** it must schedule quantities of gas nominated by a User for receipt at Receipt Points and for delivery at Delivery Points subject to any adjustments the Service Provider deems necessary. The AER considers that **clause 6** should be amended to remove the words "and subject to certain other exceptions" as it is too uncertain and the clause otherwise provides NT Gas with sufficient discretion. Under **clause 7** where there is not sufficient capacity to transport all quantities of gas nominated by Users on a day, NT Gas has proposed a priority sequence beginning with quantities nominated under Firm	Delete *"and subject to certain other exceptions"* from clause 6. Amend the definitions of Overrun Quantity and Overrun Charge in Schedule 2 by adding *"Overruns may be authorised or unauthorised."* Amend Schedule 1 by adding *"Authorised Overrun Rate: 120% of Reference Tariff"* and adding *"Unauthorised"* at the beginning of "Overrun Rate: 250% of Reference Tariff."

600 NT Gas, *Access arrangement for Amadeus Basin to Darwin Pipeline*, February 2003, p 4.

601 APT Petroleum Pipelines Limited, *Access arrangement for Roma Brisbane Pipeline*, 28 March 2007, p 8.

602 NT Gas, *Access arrangement for Amadeus Basin to Darwin Pipeline*, February 2003, p 13.

603 APT Petroleum Pipelines Limited, *Access arrangement for Roma Brisbane Pipeline*, 28 March 2007, p 12.

	Transportation Agreements. PWC submitted that given PWC's role in providing an essential service and its historical role in underwriting the pipeline, it should have initial priority under **clauses 6, 7 and 10**. The AER considers that such priority would not be acceptable given the non-discrimination provision in the Access Arrangement (s. 2.1.3). The AER considers that as **clause 7(a)** has the potential to severely impact on users that NT Gas should confine any rescheduling to the portion(s) of the pipeline that are affected by capacity constraints. The AER notes that the operation of clause 7 is "subject to …the operability of applicable…pipeline networks" which may possibly confine any rescheduling to only certain portions of the pipeline but as this is not clear, the AER considers it necessary to include an express provision to this effect. **Clause 7(b)** does not include excesses pursuant to authorised overruns. PWC submitted that in the Services provided by the Service Provider there is no provision for authorised overruns and request than the Terms and Conditions include provision for such i.e. for transport of gas in excess of the MDQ or MHQ that would encompass a reasonable endeavours obligation to comply with a request if capacity is available. Further, the cost of the authorised overrun service should not be at a premium to firm service. The AER notes that provision was made in the earlier access arrangement for authorised overruns.[600] Authorised overruns are also provided for in the Roma to Brisbane Pipeline access arrangement[601] which is owned and operated by the APA Group. NT Gas in its access arrangement submission has provided no reasons as to why authorised overruns are not included in its access arrangement proposal. The AER agrees with PWC that the absence of authorised overruns in NT Gas's access arrangement needs to be addressed. It considers that the provision of authorised overruns in the proposed access arrangement would better promote the national gas objective under s. 23 of the NGL. Accordingly the AER has proposed a number of amendments to the access arrangement proposal that make provision for authorised overheads. These are: ▪ include a statement in the definitions of Overrun Quantity and Overrun Charge in Schedule 2 that overruns may be authorised or unauthorised ▪ include in Schedule 1 the authorised Overrun Rate of 120 per cent of the Reference Tariff. This rate is consistent with the authorised overrun rates in the earlier access arrangement[602] and in the Roma to	Amend clause 7(a) by adding *"Such scheduling limitations will be applied only to the portion or portions of the Pipeline that are capacity constrained."* Amend clause 7(b) by adding *"pursuant to authorised overruns."* Require definition of As Available Transportation Agreement in Schedule 2.

	Brisbane Pipeline access arrangement.[603] ▪ include in clause 7(b) of the Terms and Conditions a reference to excesses that are pursuant to authorised overruns. The AER also notes that the term "As Available Transportation Agreement" as used in clause 7(c) and (d) is not defined (a point raised by PWC) and requires the inclusion of a definition to address this omission. The AER considers that clauses 7(c) and (d) are otherwise acceptable. Santos and Magellan's submit that **clause 7(d)** of NT Gas's access arrangement should be amended so that the scheduling priority for interruptible service involves allocation of available capacity for the interruptible service on a *pro rata* basis and the AER should review the non-reference services priority list against the NGR. The AER, however, notes that there are no NGR requirements that are relevant to this enquiry. The AER notes that **clause 9** permits the service provider to schedule and reschedule subject to the requirements of clauses 6 to 15, without liability to the User. No submissions were received in relation to clause 9. The AER considers that clause 9 is reasonable. No submissions were received in relation to **clause 10.** The AER considers that clause 10 is acceptable.	
Curtailment clauses 11, 12, 13 and 14	NT Gas proposed that it may curtail or interrupt the transportation or delivery of gas in accordance with a defined sequence and set of priorities if the pipeline capacity on any day is insufficient to serve all quantities of gas scheduled to Users (**clause 11**). Under **clause 12** NT Gas has proposed that it is not liable to the User if an interruption or curtailment occurs under a defined set of circumstances. It has also proposed that it will adjust delivery and receipt MDQs and daily Throughput Rate(s) to take into account differences in specified heating values when the aggregate quantities of gas to be delivered to all Users exceeds the pipeline capacity. This adjustment will not affect delivery MDQ for the purpose of calculating the Minimum Bill or Capacity Charge (**clauses 13 and 14**). Santos and Magellan submitted that the right to curtail is much wider than previous terms and conditions and that the only criterion is insufficient capacity regardless of the reason for the insufficiency. Santos and Magellan further submit that **clauses 11–14** should be amended so as: ▪ the right to curtail a service is limited to planned work, for safety reasons, to comply with the law, in	Delete clause. 12(a)(ii) Delete clause 12(a)(iii) Amend clause 12(a) as follows in order to effect the change to clause 12(c): "if the interruption or curtailment *is due to:* *(a) planned or unplanned maintenance in respect of the Pipeline and the Service Provider acts in accordance with clause 32 or clause 33; or* *(b) a Force Majeure Event."*. Delete clause 12(d)

	an emergency or event of force majeure ▪ NT Gas is required to provide reasonable notice of any curtailment ▪ NT Gas is subject to an obligation to minimise, as far as reasonably practical, any curtailment. PWC submitted that it is necessary to put a time limit on the planned and unplanned maintenance to ensure that Users "can have surety of service being provided." In addition, PWC object to clause 12(d) as providing "unreasonable relief" to the Service Provider for not providing the firm service, and request that it be deleted. The AER in reviewing subclauses **12(a)(i) and (ii)** notes that clause 32 covers planned maintenance as the User is to be given one month's notice and clause 33 covers unplanned maintenance as it is other than what is covered in clause 32 and only "as much notice…as is reasonably practicable" is required. However, clause 12(a)(ii) appears to introduce another category of unplanned maintenance in which case it is unclear what is meant to be covered and why the coverage needs to be broader than that set out in clauses 32 and 33. The AER notes in this respect that clause 33 covers "works, repairs and maintenance…in order to protect the operational integrity or safe operation of the Pipeline" and this is to be based on Good Engineering and Operating Practice. The AER therefore considers that subclause **12 (a)(ii)** is unnecessary and should be deleted. In relation to clauses 32 and 33 also, the AER requires an amendment to the drafting to clarify that the Service Provider must act in accordance with the requirements of these clauses. The AER further considers that subclause **12(a)(iii)** is not acceptable as the AER cannot envisage in what other circumstances such curtailments and interruptions would be necessary and NT Gas has not offered any specific justification for this subclause. The AER therefore considers that this subclause should be deleted. The AER considers that **subclause 12(c)** does not clearly establish a link between the force majeure event and the interruption and curtailment and requires the deletion of clause 12(c) and the amendment of clause 12(a) to take this change into account. With regard to **subclause 12(d),** the AER has considered the comments of Users and notes that this clause sets a very high threshold for liability of the service provider given that it is reasonable to expect the Service Provider to maintain and operate its assets in all circumstances excepting where events are beyond its control and/or where risk is more appropriately assigned to the user. As such, the AER considers that where the Service Provider's act or omission is the cause of a curtailment or interruption, it should bear the risk in such circumstances. The AER therefore considers that subclause 12(d) should be deleted.	Amend clause 14 by adding words '*provided for in clause 13*' after the word adjustment. Definitions to be included for Minimum Bill and Capacity Charge.

	The AER notes Santos's suggestion that reasonable notice always be given to Users. The AER considers that this is unnecessary given the deletion of various of the subclauses in clause 12 and given that clause 32 requires one month notice and clause 33 requires notice as reasonably practicable. For similar reason, the AER considers that Santos's request that the right to curtail or interrupt services be subject to an obligation to minimise, as far as reasonably practical, any curtailment is not necessary given the deletion of various of the subclauses in clause 12. Those remaining already include an obligation to minimise disruption (clause 32) or are appropriately qualified (in clause 33, "to the extent necessary") and if a Force Majeure Event occurs, the AER considers that the Force Majeure Event provisions provide sufficient incentive for a party to use its reasonable endeavours to remedy the situation. The AER has considered PWC's submission in relation to the need for surety of service but considers that it is not appropriate to set a strict time limit on the amount of maintenance that can be undertaken especially where such maintenance may result from a Force Majeure event. The AER also notes that no such time limit applied in the earlier access arrangement. No submissions were received in relation to **clause 13**. The AER considers that clause 13 is acceptable. No submissions were received in relation to **clause 14**. The AER considers that clause 14 is acceptable though it notes that definitions of Minimum Bill and Capacity Charge have yet to be included (see above requested amendment).	
Imbalances clauses 15, 16, 17, 18 and 19	NT Gas proposed that a User must use reasonable endeavours to ensure that receipts and deliveries of gas at Receipt and Delivery Points are equal and have been adjusted for any Authorised Imbalances (**clause 15**). Under **clause 16**, NT Gas proposed that the User must promptly take steps to correct Unauthorised Imbalances or potential Unauthorised Imbalances by adjusting its Nominations and co-ordinating receipts and deliveries with the Service Provider. NT Gas has also proposed that the Service Provider may correct an Unauthorised Imbalance by reducing or buying sufficient quantities of the User's gas, where a User has not taken reasonable steps to correct such an imbalance (**clause 17**). If the Service Provider purchases gas to make such a correction, then the User will indemnify the Service Provider for 130 per cent of all the Service Provider's costs incurred. The Service Provider may retain 30 per cent of the proceeds of the sale to make a correction (**clause 18).** Under **clause 19** the Service Provider is not responsible for eliminating any imbalances between the User and an Interconnect Party. Santos and Magellan have submitted that for the purposes of **clause 17** and consistent with the National Gas Objective, the User's obligation to correct the imbalance should only be to the extent that the	Amend clause 17 as follows: Delete the words "as necessary or" and replace with "*to the extent necessary to enable NT Gas to comply with any requirements under the Transportation Agreement or to operate the Pipeline properly or, with the consent of the User,…*" Amend clause 18 as follows: *"The User will indemnify the Service Provider for 100% of all costs and expenses reasonably incurred by the Service Provider in purchasing Gas to make a correction."*

	imbalance will impair the ability of NT Gas to transport the quantities of gas scheduled under the user's agreement or any other agreement. Also the User should be permitted to elect whether NT Gas will reduce the user's gas by reducing the user's receipts or buying or selling the user's gas. Further, Santos and Magellan have submitted that **clause 18** is not reasonable as it constitutes a penalty for the User having an imbalance. Santos and Magellan have also submitted that if the AER allows for NT Gas to indemnify all costs and expenses it incurs in seeking to correct an imbalance then this indemnity should be limited to 100 per cent of the reasonable costs incurred by NT Gas. Similarly, PWC submitted also that the User should only be required to reimburse the Service Provider of its costs reasonably incurred in purchasing the relevant quantity of gas. PWC objected to the Service Provider being able to sell the User's gas without the User's agreement. PWC submitted that no Imbalance Charge should be payable given the availability of cost reimbursement under these provisions. The AER accepts that NT Gas, under **clause 17**, should be able to reduce the User's receipts and/or deliveries of quantities as necessary. The AER notes that NT Gas must have "reasonable grounds" for acting so. The qualification that there needs to be "reasonable grounds" requires the Service Provider to have made an assessment that the imbalance may impair the ability of NT Gas to transport the quantities of gas scheduled under the User's agreement or any other agreement. However, the AER also accepts Santos and Magellan's comments that any reduction in the User's receipts and/or deliveries should be clearly confined. Therefore the AER requires that clause 17 be amended to reflect this. Such an amendment will reflect the nature of the obligation as set out in the previous Terms and Conditions. Further, the AER does not accept Santos's submission that the Users should be permitted to elect whether NT Gas will reduce the user's gas by reducing the user's receipts or buying or selling the user's gas. The AER accepts that NT Gas should be in a position to make a determination, on reasonable grounds, and "as necessary" that it may correct an imbalance by making a reduction. However, as the title to the gas in the pipeline remains with the User, the AER does not consider it appropriate in **clause 17** for the service provider to buy or sell the User's gas without the User's consent. The AER requires an amendment to this effect. As to recovery of costs under **clause 18**, it is not clear to the AER on what basis NT Gas arrived at the figure of 130% which in the AER's view could lead to NT Gas receiving an amount in excess of its costs. For like reasons, the AER considers that it is not appropriate, under **clause 18**, for the servicer provider to retain 30% of the proceeds of sale of the User's gas to make a correction. The AER notes the absence of any justification to support these figures and as a result considers these terms to be unreasonable.	

	Therefore the AER considers the following amendments are required: ▪ clause 18 be amended so that the indemnity under clause 18 be limited to 100 per cent of the reasonable costs incurred by NT Gas; ▪ clause 18 be amended to allow the servicer provider to retain the reasonable costs incurred in the sale of the User's gas, the sale of which, as noted above, will be subject to the User's consent. The AER notes that an Imbalance Charge will apply in addition to these costs and PWC's view that this is not appropriate and its claim that no such charge applied under the earlier access arrangement. However, the AER considers these cost reimbursements address the costs in correcting the imbalance through the sale and purchase of gas whereas the Imbalance Charge is intended to provide incentive for the User not to cause an imbalance and to act promptly to correct an imbalance. Further, under clause 4.5 of the Access Arrangement a Service Provider "may charge the User an Imbalance Charge" and therefore such a charge may not always be applied. The AER also notes that in the earlier access arrangement an imbalance rate could be applied in addition to a user paying a charge to NT Gas which was the equivalent of the amount paid by NT Gas for gas used to correct an imbalance shortfall. For these reasons the AER does not accept PWC's submission on this point. The AER considers that clause 19 is acceptable.	
Adjustments to Rates and Charges/Additional Payments clauses 20, 21, 22 and 23	**Under clause 20** NT Gas has proposed that it may adjust rates and charges to recover any New Impost which would increase the cost of providing services by more than a trivial amount. It has proposed that the User transfer or pay the value of permits used, held or surrendered as well as paying the Service Provider any other costs incurred in relation to greenhouse gas emissions (**clause 21**). NT Gas has also proposed that under **clause 22** adjustments will be made to amounts payable by Users if there is a change in law which results in a change in costs incurred by the Service Provider. It has further proposed that all tariffs, charges and amounts payable under the Access Arrangement be exclusive of GST (**clause 23).** Santos and Magellan raised concerns with **clauses 20 and 21** in that they are drafted too widely and permit NT Gas to act inefficiently in its pass through of costs. In particular it submits that: ▪ these clauses are inconsistent with r. 97(1)(c) with respect to cost pass throughs as a tariff variation	Deletion of clauses 20, 21 and 22. Delete definitions of Impost, New Impost, Greenhouse Law, Emissions Permit and Substitute Permits.

	being approved by the AER ■ NT Gas should only be entitled to pass through those taxes, charges. which increase the direct costs of providing services ■ NT Gas should be required to minimise any such costs (acting reasonably) ■ clause 20 should be amended to include a mechanism which provides for any decreases in cost to be rebated to a user ■ clause 21 should be amended so that the user is only liable to reimburse direct carbon costs incurred by NT Gas in providing pipeline services and not for indirect costs or costs of NT Gas's related corporate entities. PWC submitted that a cost pass through event should be limited to the net financial effect resulting from a Change in Law (defined to mean a new law or a change in existing law) but only to the extent it affects pipeline operations. It further submitted that the risk of events that fall within the normal definition of Force Majeure should lie where they fall and be covered by a Service Provider's insurance not passed on to users. PWC maintains that costs associated with assets that have no future purpose in delivery of services should not be passed to users and that costs decreases should be passed through by the Service Provider. The AER has reviewed clause 20 and notes that the provider can recover the amount by which the New Impost increases the service provider's costs such that the amount charged could possibly exceed the actual cost of the New Impost. Also, the AER notes that the definition of a "New Impost" includes a carbon tax so where this tax, once introduced, is increased, any cost will be borne by the User where it "has the effect of changing the Service Provider's cost of delivering the Services under the Transportation Agreement" even though such costs may not be directly associated with the tax. Overall, the AER considers that such a clause is unnecessary given that a cost pass through mechanism is already available under the Access Arrangement. Such a provision could possibly circumvent the process of approving cost pass throughs as part of their proposed tariff adjustment (see sections 4.7.2 and 4.7.3 of the proposed access arrangement which are assessed by the AER in section 11.5 of this decision). The AER is requiring an amendment to NT Gas's proposed cost pass through mechanism that allows users to	

	benefit from unexpected events that lead to a material reduction in the service provider's costs. The AER considers that the definition of Cost Pass-Through Event is sufficiently broad to cover New Imposts as defined as well as any costs which result in respect of a Greenhouse Gas Law as defined. The cost pass through mechanism as provided for under r. 97 of the NGR is designed to address the kinds of cost increases and decreases that may arise from the introduction of or changes to such laws including the possible introduction of a carbon tax but each will need to be assessed in line with the definition of a Cost Pass-Through Event and the reference tariff variation mechanism under the oversight of the AER. For these reasons, the AER requires the deletion of clause 20. For the same reasons, the AER requires the deletion of clauses 21 and 22. The AER further notes in relation to clause 22, that the "change in law" contemplated appears to be indistinguishable from any change in law that may have resulted from an Impost or New Impost. As a consequence of the AER's conclusions, the definitions of Impost, New Impost, Greenhouse Law, Emissions Permits and Substitute Permits are required to be deleted. The AER considers that the deletion of these clauses will effectively address the submissions made by Santos and Magellan and PWC.	
System use gas and line pack clauses 24, 25, 26, 27, 28 and 29	NT Gas has proposed that each User must supply a quantity of System Use Gas required by the Service Provider to operate the pipeline (**clause 24**). Under **clause 25** NT Gas has proposed that it will determine the quantity of System Use Gas to be provider by a user each month by taking the proportion of the gas delivered to the User to the quantity of gas delivered to all Users. The Service Provider will own the System Use Gas supplied by the Users (**clause 26**). The Service Provider will also supply and own a quantity of gas to ensure that it can operate the pipeline in accordance with good engineering and operating practice (i.e. Base Line Pack) (**clause 27**). Under **clause 28** NT Gas has proposed that the User will provide Line Pack in addition to the Base Line Pack, on the first day the User uses the Firm Service and at other times as advised by the Service Provider. The quantity of gas provided by the User for Line Pack will be determined by the Service Provider by taking the proportion that the Delivery MDQ bears to the total of all Users' MDQs. Under **clause 29** the User is required to give APA directions about the delivery of the User's Line Pack on or before the end of the transportation agreement, otherwise title to the User's Line Pack transfers to the Service Provider. PWC submitted that the Service Provider should provide:	Amend clause 25 to include the following: *"The Service Provider will provide all Users a monthly statement showing the calculation and the amount of gas used for System Use Gas."* Amend clause 28 to include the following*:* *"The Service Provider will provide all Users a monthly statement showing the movement of User's Line Pack."* Amend clause 29 as follows: *, and the Service Provider must comply with such directions at no cost to the User.*"

	▪ calculation of monthly statement of System Use Gas used; and ▪ monthly statement in movement of User's Line Pack. The AER considers that PWC's request is reasonable because NT Gas should be determining quantities of gas required on a regular basis for it to operate the pipeline in accordance with good engineering and operating practice. In the case of System Use Gas NT Gas determines each month the quantity of gas to be provided by the Users. Therefore the AER requires that **clauses 25 and 28** be amended to include the requirements that the Service Provider provide to the Users monthly statements showing the calculation and the amount of gas used for System Use Gas and the movement of Users' Line Pack. PWC submitted that an additional clause is required under which the Servicer Provider should be obliged to follow the User's instructions for redelivery of Line Pack before the end of term at no cost to the User. The AER considers that **clause 29** should be amended to provide that APA must comply with such directions and that it should be clarified that this is at no cost to the User.	
Operation of pipeline clauses 30, 31, 32, 33, 34 and 35	Under clauses 30 to 35 NT Gas has proposed how it will operate the pipeline. It is required to operate and maintain the pipeline in accordance with good engineering and operating practice and provide services subject to compliance with all laws and approvals (**clauses 30 and 31**). Under **clause 32** the Service Provider must give the User at least one month's notice of its intention to curtail services due to repairs and maintenance. These repairs are to be made during a period of forecast relatively low aggregate demand so as to avoid or minimise disruption. If for operational integrity or safety reasons the Service Provider determines that repairs are required, it will give the User as much notice of the proposed curtailment as is reasonably practical (**clause 33**). Under **clause 34** NT Gas has proposed that the User ensures that its arrangements for gas supply and acceptance at receipt and delivery points are compatible to the Service Provider's pipeline operations. It has also proposed that the User must provide access to the Service Provider relevant charts, records and data including relevant measurement and SCADA information (**clause 35**). PWC submitted that the words "without liability to the User" should be deleted from clause 32 which sets out the nature of the Service Provider's obligations when undertaking planned works, repairs or maintenance. The AER agrees with PWC that the words "without liability to the User" should be removed from **clause**	Amend clause 32 as follows: Delete the words *"without liability to the User"* Amend clause 35 as follows: *"The User must facilitate the Servicer Provider's access as reasonably required by the Servicer Provider to relevant charts…"*

	32. It is within the Service Provider's control to manage planned maintenance in accordance with the terms of clause 32. The AER also notes that under clause 12 the Service Provider's liability in relation to the insufficiency capacity of the Pipeline is also reduced to the extent that it acts in accordance with clause 32. The AER also notes that this is consistent with the approach adopted in the previous Terms and Conditions. The AER considers that **clauses 33 and 34** are acceptable. Santos and Magellan submitted that **clause 35** should be limited to such data as is reasonably required by NT Gas to provide the pipeline services under the agreement. The AER agrees that the data provided under clause 35 should be limited to what is reasonably required by the Servicer Providers noting that the costs of providing such data will be borne by the User.	
Metering clauses 36, 37, 38, 39 and 40	NT Gas has proposed that it will install, operate and maintain metering equipment at receipt and delivery points unless otherwise agreed. If there is any other metering equipment used to measure and monitor gas at receipt and delivery points then this equipment must conform to the Service Provider's metering requirements (**clause 36**). NT Gas has also proposed that the User will at its cost provide, operate and maintain all metering equipment required for the purposes of its Transportation Agreement (**clause 37**). This includes installing facilities at receipt and delivery points that will permit co-ordination of metering, scheduling and transportation activities by the Service Provider and the User (**clause 38**). It has further been proposed that all parties ensure that access is provided to their respective metering equipment to permit inspections and testing to be carried out (**clause 39**). Under **clause 40** NT Gas has proposed that the Service Provider's Metering and Measurement Requirements govern the measurement of Gas unless otherwise negotiated by the Parties. Santos and Magellan submitted that **clause 40** regarding the metering arrangements should be specified in the Terms and Conditions rather than being left to NT Gas's discretion. PWC submitted that as the Metering and Measuring Requirements are as published by the Service Provider from time to time at its discretion and as these may require the User to upgrade facilities, such requirements are one sided and defeat the purpose of an access arrangement. The AER considers that the Metering and Measuring Requirements form part of the terms and conditions and are not separate to these terms and conditions and as such should be attached as a Schedule to the Terms and Conditions. This will necessarily establish what the relevant requirements are as of the date of the contract.	Attach as a schedule to the Terms and Conditions the current version of the Metering and Measuring Requirements. Insert new clause: *"The Service Provider will provide reasonable notice to the User of any changes to the Metering and Measuring Requirements and such changes are to be reasonably determined by the Servicer Provider."*

	The AER notes that clause 40 is qualified in that the parties may agree that the Metering and Measuring Requirements do not govern the measurement of Gas. However, the AER considers that the concerns submitted by Users are justified to some extent. As the Requirements are subject to unilateral change at any time, the AER considers that such change should be reasonable given that it could result in a costly upgrade of User facilities. The AER also considers that Users should receive reasonable notice of any such changes. The AER has included a new clause to effect these changes.	
Quality clauses 41, 42, 43, 44, 45 and 46	NT Gas has proposed that gas delivered at a receipt point must be of a quality to meet the Gas Specification requirements. The Service Provider may vary the specifications if it is required to do so by law or any authority (**clause 41**). Under **clause 42** NT Gas has proposed that the Service Provider may allocate costs incurred resulting from changes to the Gas Specification to all Users. If gas offered for transportation is Off Specification Gas then the User must immediately notify the Service Provider (**clause 43**). Under **clause 44** the Service Provider may refuse to accept Off Specification Gas. If the User offers and NT Gas accepts receipt of Off Specification Gas then the Service Provider is indemnified by the User against any loss or damage suffered or incurred as a result of transporting this gas (**clause 45**). Under **clause 46** NT Gas has proposed that it is responsible for any loss or damage it, the user or any other person suffers or incurs if the User has notified it in writing to reject the receipt of Off Specification Gas and NT Gas could reasonably have stopped receipt, transportation or deliveries. In relation to **clause 41**, Santos and Magellan submitted that gas specifications should be specified in the Terms and Conditions rather than leaving them to NT Gas's discretion. Further, **clause 42** should be amended to provide that: ▪ only direct unavoidable costs can be passed through ▪ if a change to the gas quality specifications decreases NT Gas's costs, those costs should be rebated to all users in the same way that increases to costs are. PWC submitted, with regard to **clause 43**, that in addition to the User notifying the Service Provider immediately on becoming aware that gas offered for transportation is or may be Off-Specification gas, the Service Provider should also have a similar obligation to notify the User as soon as it becomes aware that gas entering or leaving the pipeline is Off-Specification Gas. In relation to **clause 41**, the AER considers that the gas specifications form part of the Terms and Conditions and the current version should be included in the Terms and Conditions. In addition, the definition of Gas Specification will require amendment to reflect this. The AER also considers that it is not	Attach as a schedule to the Terms and Conditions the current version of the Gas Specifications. Definition of Gas Specification to be amended as follows: "Gas Specification means the gas specifications in Schedule [X] and currently available at http://www.apa.com.au/media/185586/gas%20specification%20-%20agp.pdf." Include new clause as follows: *"The Service Provider's right to vary the Gas Specifications is subject to the recognition and preservation of existing contractual rights and obligations."* Amend clause 42 as follows: Delete all words from *"Without limiting…such costs on demand."* Amend clause 43 as follows: "*The User and the Servicer Provider must each notify the other* immediately…." Include definitions of Minimum Bill and Capacity Charge.

	necessary for the definition to include aspects of the Service Provider's right to amend those specifications or the requirement that these comply with applicable laws or that the Service Provider is to advise the User, as these terms are more appropriately and sufficiently set out under clause 41. The AER further notes that in the previous Terms and Conditions, variation was subject to existing contractual rights and obligations. The AER is of the view that variation should include this same protection for Users with service agreements given that the Service Provider can vary the specifications unilaterally. The AER has included a new clause to this effect. **Clause 42** is effectively a provision which seeks to pass on costs to the User where there has been a change in the law or a regulatory obligation. The AER considers that such an event is more appropriately dealt with under the cost pass-through provisions of the access arrangement for similar reasons set out in relation to clauses 20, 21 and 22. The AER therefore requires the deletion of part of this clause. In relation to **clause 43**, the AER agrees with PWC that the Service Provider should have a corresponding obligation to inform the User immediately on becoming aware that gas entering or leaving the Pipeline is Off-Specification Gas. In relation to **clause 44**, the AER also notes the omission of a definition of Minimum Bill and of Capacity Charge. The AER requires that the Servicer Provider include definitions for both terms. The AER considers that clauses 45 and 46 are acceptable.	
Receipt pressures clauses 47, 48 and 49	NT Gas has proposed that the User must supply gas to the Service Provider at Receipt Points which is at a pressure nominated by the Service Provider. This pressure is to be sufficient as to allow gas to enter the pipeline but can not be greater than a set maximum pressure determined for each Receipt Point (**clause 47**). If the User does not meet this requirement then it must indemnify the Service Provider for all resulting loss and damage suffered or incurred by the Service Provider (**clause 48**). NT Gas has also proposed that it is under no obligation to install inlet compression or other facilities to permit the entry of User's gas into the pipeline (**clause 49**). Santos and Magellan submitted that under NT's proposed clause 47 (as under the previous terms and conditions) no methodology is set for determining the maximum pressure and there is no transparency in the process of NT Gas setting the gas pressure for each receipt point. However, unlike the previous Terms and Conditions, these new Terms and Conditions include that the User must indemnify NT Gas against loss or damage as a result of the User failing to comply with the pressure obligations and the indemnity is not subject to the limitation of liability to direct damages only (clause 79(f)). Santos and Magellan	Amend clause 47 as follows: "The User must supply Gas to the Service Provider at the Receipt Points at pressures nominated by the Service Provider…but in no case greater than *the Receipt Point Pressure or the maximum allowable operating pressure*." Include a definition of Receipt Point Pressure. Amend clause 48 as follows; "…the above obligation *to the extent that the loss or damage was not caused or contributed to, by the negligence of the Service Provider*." Insert new clause:

	submitted that theses clauses should be amended as follows: ▪ the maximum pressure should be determined in consultation with the user or alternatively by NT Gas acting reasonably ▪ the indemnity in clause 48 should be reduced to the extent that the loss or damage was caused or contributed to by NT Gas's negligence. In relation to **clause 47**, PWC's submission accepts that the gas must be supplied at the Receipt Points at pressures nominated by the Servicer Provider from time to time as being sufficient to allow the gas to enter the pipeline but submits that the User should not be required to deliver gas at a Receipt Point at pressures in excess of the Receipt Point Pressure or the maximum allowable operating pressure (MAOP). PWC also submits that the Terms and Conditions should include a requirement, subject to the User providing sufficient Gas at the Receipt Point and at the required pressure, for the Service Provider to deliver Gas for User's account at the Delivery Point Pressure. In relation to **clause 47**, the AER notes that no maximum pressure is identified in the Terms and Conditions. Given the indemnity sought by NT Gas, which is a new provision, the AER agrees with Santos and Magellan that clause 47 should be amended. The AER considers that rather than requiring NT Gas to reasonably determine pressure, it is sufficient to adopt PWC's approach that the User should not be required to deliver gas at a Receipt Point at pressures in excess of the Receipt Point Pressure or the MAOP. This will be a clearly defined pressure whereas under the existing provision the reference to "set maximum pressure" leaves open the possibility that this may be other than the Receipt Point Pressure or MAOP. This will clarify and balance the obligations of the Servicer Provider and the User and will ensure security of supply of natural gas in line with the National Gas Objective. The AER notes Santos and Magellan's comments in relation to **clause 48.** While the User's liability is confined to loss or damage causes "as a result of the User breaching the above obligation", the AER accepts that the indemnity in clause 48 should be reduced to the extent that the loss or damage was caused or contributed to by NT Gas's negligence and accordingly, clause 48 is to be amended. The AER also accepts PWC's submission that there should be a requirement for the Service Provider to deliver Gas for User's account at a certain pressure. The AER notes that there is no definition of Delivery Point Pressure and that in the previous Terms and Conditions there was a requirement for delivery at pressure as agreed between the parties "which will be not less than 2000 kPa(a)." As the pipeline is	*"Providing gas is received by the Service Provider in accordance with these conditions, the Service Provider will deliver Gas to the User's Delivery Points at the pressure agreed between the Service Provider and the User."*

	operating at higher pressure than previously, and this figure may no longer be appropriate, the AER has resolved that the pressure should be as agreed between the Parties. . No submissions were made on clause 49. The AER considers that **clause 49** is acceptable.	
Possession of gas and responsibility clauses 50, 51, 52 and 53	NT Gas has proposed that it will have control and possession of gas following receipt of gas from the User and prior to the delivery of gas. This is net of any System Use Gas provided by the User (**clause 50**). The Service Provider will not be responsible for losses of the User's gas while the gas is in the Service Provider's control and possession (**clause 51**). NT Gas has also proposed that the Service Provider will have no responsibility or liability with respect to any gas prior to its supply at Receipt Points or after its delivery to Users at Delivery Points (**clause 52)**. Under **clause 53** NT Gas has proposed that gas received at Receipt Points may be commingled with gas in the pipeline. It may also deliver gas to Users in a commingled state. The AER considers that **clauses 50, 51 52 and 53** are acceptable.	
Warranties and representations clause 54	NT Gas has proposed that the User warrants and represents that it has title to and the right to supply gas for transportation under its Transportation Agreement (**clause 54)**. No submissions were received in relation to clause 54 and the AER considers that **clause 54** is acceptable.	
Title clause 55 and 56	NT Gas has proposed that the title to gas received at the Receipt Point does not pass to the Service Provider except for any liquid hydrocarbons which condense or separate out of the gas, System Use Gas or where the jurisdiction is in Western Australia (**clause 55)**. In Western Australia title to the gas passes to the Service Provider at the Receipt Point and reverts to the User at the Delivery Point (**clause 56)**. No submissions were received on **clauses 55 and 56** and the AER considers both are acceptable. The AER further considers that an additional clause should be included to provide certainty on the rights of the Parties on termination as provided for in the earlier access arrangement.	Include new clause as follows: *On the termination of a Service Agreement, the User will be entitled to:* *(a) recover a quantity of gas equivalent to any quantity delivered by or on behalf of the User into the Pipeline (net of System Use Gas) and not delivered to or for the account of the User; or* *(b) sell the gas to another User and advise the Service Provider of the quantity and identity of that User.*
Allocation of receipts and deliveries clause 57, 58, 59 and 60	NT Gas has proposed that it can allocate amongst Users any quantities of gas received at the Receipt Points or delivered at the Delivery Points that do not equal the quantities Scheduled by the Service Provider (**clause 57)**. If quantities of gas are delivered to a Delivery Point which is a hub then such quantities will be allocated firstly based on the User's Scheduled deliveries for that Delivery Point, secondly in accordance with the STTM Rules and thirdly on a *pro rata* basis according to the User's Scheduled	Delete clause 58. Amendment to clause 59: Delete phrase "*to the above methodologies*"

	deliveries (**clause 58)**. NT Gas has also proposed that all Users for a Receipt Point or Delivery Point agree on an alternative allocation methodology then the Service Provider may apply such an alternative methodology (**clause 59)**. NT Gas may revise its allocation methodology from time to time to reflect as far as reasonably possible any allocation methodology imposed by a third party in respect to a particular Receipt or Delivery Point (**clause 60)**. The AER notes that **clause 58** refers to gas delivered to a hub and STTM rules. As there is no hub or STTM proposed for NT, the AER considers that clause 58 is irrelevant for the AGP and this clause should be deleted. The AER also requires an amendment to **clause 59** to reflect that clause 58 is deleted. Santos and Magellan have submitted that **clause 59** should be amended to require NT Gas to apply any methodology agreed by the users. PWC submitted that clause 59 (PWC refers to clause 57 but the AER understands this to mean clause 59) is indicative of the one sided and discretionary clauses that defeat the purpose of an access arrangement. The AER notes that under clauses 20 and 21 of the previous Terms and Conditions that the Users could establish allocation methodologies. While this new provision proposed by NT Gas removes this ability of the Users to make such a determination, the AER considers that allocation of the gas on a pro rata basis is reasonable and it remains open to the Service Provider to apply an alternative methodology as agreed between Users. Such an approach is consistent with ensuring the efficient operation of natural gas services in line with the National Gas Objective. The AER therefore does not require any amendment to clause 59 other than that noted above.	
Addition of receipt points and delivery points clause 61, 62, 63, 64, 65 and 66	NT Gas has proposed that the User may by notice to the Service Provider request that the Service Provider provide services under the Transportation Agreement to receipt and delivery points in addition to those set out in the Transportation Agreement (**clause 61)**. This notice must specify certain details such as the proposed location of the additional receipt or delivery points, MDQ, MHQ, changes to existing MDQs and MHQs, date of commencement and period required (**clause 62**). NT Gas has also proposed that it will determine whether and the extent to which it is able to meet the User's request and if so any applicable conditions on which it will accept (**clause 63**).Under **clause 64** NT Gas has proposed a number of conditions on which it will not agree to the User's request. Also under **clause 65** NT Gas has proposed a number of conditions on the construction or modification of addition receipt and delivery points. Finally under **clause 66** NT Gas has proposed that where a receipt or delivery point has been added, the amount payable under the Transportation Agreement will be no less than what was payable prior to the addition. Santos and Magellan submitted that **clause 65(e)(ii)** should be amended to clarify that the User is only liable to compensate NT Gas for obtaining a reasonable rate of return on capital expended to make the	Amend clause 65(e) as follows: "the User must pay *only the incremental costs that are considered reasonable and efficient which have been* incurred by the Service Provider in" Amend clause 65(e)(i) as follows: "*designing and* constructing the additional receipt point or additional delivery point *to the appropriate industry standard*" Amend clause 65(e)(ii) as follows: "obtaining a reasonable rate of return on capital expended to make the additional receipt point or additional delivery point available to the User, *where the costs are being recovered over*

	additional receipt or delivery point, where the costs are being recovered over time. PWC submitted that these provisions should cover more generally all new facilities irrespective of whether associated with a receipt or delivery point. Further the Service Provider should ensure costs of new facilities are reasonable and efficient and designed consistent with appropriate industry standards. PWC submitted that the User be only liable for the incremental cost of operating and maintaining any improvements (if any), recognising that there may be savings on any replaced facility. The AER agrees with the views expressed in submissions and considers that the costs of additional receipt or delivery points may be recovered over time and that the costs of new facilities should be reasonable and efficient reflecting appropriate industry standards. The AER also considers that Users should only be required to pay the incremental costs associated with additional receipt and delivery points recognising that there may be savings made where these facilities are replacing existing facilities. Such an approach is consistent with ensuring the efficient operation of natural gas services in line with the National Gas Objective. The AER therefore requires amendments to clause 65(e) that address the concerns noted above.	*time*"
Dispute resolution clause 67, 68 and 69	NT Gas has proposed that where there is a dispute of an accounting, engineering or scientific nature between parties with respect to the Transportation Agreement then either party may refer to an independent expert for a determination (**clause 67)**. The independent expert's decision in the absence of manifest bias or error will be final and binding on the parties (**clause 68)**. NT has also proposed that once a dispute is referred to an independent expert for determination then neither party may commence or continue court proceedings in relation to that dispute (**clause 69)**. No submissions were received regarding these provisions. The AER considers that clause 67 should be amended to require that both parties must agree to refer an issue of the kind described in clause 67 to an independent expert. In order for the dispute resolution provisions to work effectively there must be agreement to make such a referral if the decision of the independent expert is to be accepted as final and binding under clause 68. The AER further considers that in the event there is no such agreement the Parties may request that the Institute of Arbitrators nominate a person who has appropriate commercial, technical and practical experience.	Amend clause 67 as follows: "The Parties *by mutual agreement,* may refer for determination by an independent expert….Transportation Agreement. *In the absence of such agreement, the Parties may request that the Institute of Arbitrators nominate a person with appropriate commercial, technical and practical experience to determine the issue*."
Default clauses 70, 71 and 72	NT Gas has proposed that the Transportation Agreement may by written notice be terminated or suspended by a party after seven business days for financial default and after 21 business days for a non-financial default (**clause 70**). In addition a non-defaulting party may sue for damages or exercises any other legal or equitable remedy (**clause 71**). NT Gas has also proposed that such a termination will not affect any rights	

	or obligations which may have accrued prior to the termination (**clause 72**). No submissions were received in relation to **clauses 70, 71 and 72**. The AER considers these clauses acceptable.	
Billing and payment clauses 73, 74, 75 and 76	NT Gas has proposed that it will render monthly accounts (**clause 73**) and that the User will pay the Service Provider's tax invoices by the Payment Date otherwise interest will be charged on late payments (**clause 74**). It has also proposed that any disputed amount (including interest) which is subsequently found to be payable will be due no later than 14 days after the issue of an adjustment note by the Service Provider (**clause 75**). If an error is discovered in any tax invoice, then the error will be adjusted with interest on the next tax invoice, however no adjustments will be made if the error is discovered more than 12 months after the delivery of gas (**clause 76**). Santos and Magellan have submitted that the Terms and Conditions should specify the interest charge that is payable under **clause 74.** PWC did not make any comment about clause 74 though it made a general comment that many clauses lacked proper specificity and the AER considers that this comment may be applicable with respect to clause 74. Taking the view that the User should be fully informed of the rate that interest will be charged, the AER considers that it is necessary for the Terms and Conditions to specify the applicable interest rate. The AER considers that the Commonwealth Bank corporate overdraft reference rate plus two percentage points represents an appropriately commercially-based interest charge rate and has included an amendment to this effect. The AER considers that **clauses 73, 75 and 76** are acceptable.	Amendment to clause 74: "The User will pay the Service Provider's tax invoices by the Payment Date. *Late payment will attract an interest charge payable at the Commonwealth Bank corporate overdraft reference rate plus two percentage points*."
Information interface clauses 77 and 78	NT Gas has proposed that it retains ownership of all intellectual property rights in the Information Interface. It has also proposed that it will grant the User a non-exclusive, non-assignable, non-transferable right to access the Information Interface solely for the purpose of submitting or receiving information regarding receipts, deliveries, balances and gas flows under the Transportation Agreement (**clause 77**). **Clause 78** sets out the User's liability for any loss incurred by the Service Provider resulting from use of the Information Interface by such of the user's employees. Santos and Magellan have submitted that **clause 78** should be amended to provide that:	Clause 78 to be amended as follows: "…above right of access. *The User is liable for loss incurred by the Service provider resulting from the User's employees negligence or misuse of the Information Interface other than loss caused by the negligence of the Service Provider."*

	■ the user is subject to liability for direct damages only ■ the user is only liable where a user's employees misuse the information interface or act negligently. In addition, the user's liability should be reduced in the event, and to the extent, of any negligence by NT Gas. No submissions were received in relation to **clause 77**. The AER considers that clause 77 is acceptable. In relation to **clause 78**, the AER considers that it is within the control of the User to manage its employees' use of the Information Interface. However, the AER agrees with the submission by Santos and Magellan that the liability of the User should be confined to situations where a User's employees misuse the information interface or act negligently and that the User's liability should be reduced in the event and to the extent of any negligence by NT Gas. NT Gas is therefore required to amend clause 78. The AER notes the submission by Santos and Magellan that liability be limited to direct damages only but given the required amendments outlined above considers this unnecessary to limit liability in this manner. The AER considers that these amended provisions will more clearly articulate the User's liability.	
Limitation of liability and indemnity clauses 79, 80 and 81	NT Gas has proposed that neither party is liable to the other party in respect of the Transportation Agreement except for the User's liability in relation to a number of defined conditions (**clause 79**). Under **clause 80** NT Gas has proposed that the aggregate liability of the Service Provider in respect of the Transportation Agreement will be limited to a monetary liability cap set under the Transportation Agreement. NT Gas has also proposed that the User indemnifies the Service Provider against any liability, claim, action, loss, damage, cost or expense sustained or incurred during or after the expiry of the Transportation Agreement (**clause 81**). Santos and Magellan have submitted that: ■ Clause 79 is unreasonable and is an inappropriate allocation of risk as between the parties. Clause 79 should be amended so that both the user and NT Gas have the benefit of the limitation in the following	Amend clause 79: *"To the extent permitted by law, neither Party (including the Service Provider's Related Body Corporate) is liable to the other Party for Consequential Loss or for punitive or exemplary damages arising in respect of the Transportation Agreement except where such loss or damage arises out of:* *(a) gross negligence or wilful misconduct by either the Service Provider or the User;* *(b) the Service Provider's liability relating to the delivery of Off-Specification Gas to a Delivery Point due to its*

604 APT Petroleum Pipelines Limited, *Access arrangement for Roma Brisbane Pipeline*, 28 March 2007, p 43.

	cases: ▪ the delivery of off specification gas. If the user is liable for consequential loss for delivering off specification gas then NT Gas should be equally liable where it delivers off specification gas to the delivery point (unless otherwise agreed with the user) ▪ the obligation to deliver gas at the required pressure (for the same reasons as the treatment of off specification gas) ▪ the payment of rates, charges and other payments under the agreement (for example where NT Gas is liable to pay to the user refunds of over-payments which include interest) ▪ The following exceptions to the limitation of liability should also be deleted: ▪ the use of the information interface (if this is retained it should only apply where the user has wilfully misused the information interface - see discussion on clause 78 above) ▪ the indemnity in clause 81 ▪ Clause 80 is inconsistent with the purpose of regulated terms and conditions and the cap, if any, should be specified in the Terms and Conditions. Where damages are capped to direct damages only then the inclusion of a further liability cap is not reasonable. If the AER is minded to allow a cap it should be an amount which provides sufficient incentive for NT Gas to perform the agreement. For example, a minimum of 200 per cent of contract value. ▪ The matters referred to in clause 81(a) are acts or omissions which are the responsibility of NT Gas and not the user. It is not reasonable for the user to indemnify NT Gas and its related bodies corporate for these matters. Santos and Magellan further submitted that the indemnity in clause 81(b) is very broad and, combined with the exclusion of the limitation of liability to direct damages only (see above) potentially exposes the user to very broad damages claims. If the indemnity is retained then it should apply to both the user and NT Gas. Further, the indemnity should only cover actual losses and not extend to losses which a third party "claims	*negligence or wilful default; or* *(c) the User's liability relating to:* *(i) imbalances;* *(ii) the receipt, transportation or delivery of unauthorised Overrun Quantities* *(iii) the User's obligation to deliver gas which meets the quality required by the Gas Specification or any other quality as the law in the relevant jurisdiction requires;* *(iv) a failure to supply Gas at Receipt Points within a specified pressure range; and* *(v) the indemnity described in clause 81.* Delete clause 80: Delete of subclause 81(a). Include new clause as follows: *Each Party will be required to indemnify the other for any loss arising out of its gross negligence or wilful misconduct.*

	to suffer". PWC submitted that there should be no exceptions regarding liability for consequential loss or for punitive or exemplary damages arising in respect of the Transportation Agreement. Further, where there is a failure to deliver by the Service Provider, it should be liable for User's costs and the Transportation Charge should not apply or be reduced with respect to the gas not delivered. In relation to cap on the Service Provider's liability, PWC submitted that if a cap was agreed by negotiation, the Service Provider's liability is not limited where the liability is as a result of Service Provider's gross negligence or wilful misconduct. The AER considers **clause 79(a)** is acceptable. The AER considers that **clause 79(b)** is not acceptable as the provisions relating to late payment, which apply an interest penalty rate, and any claim for damages would be sufficient to address liabilities relating to rates, charges and other payments. The AER therefore requires the deletion of this provision. The AER notes that this deletion will address Santos and Magellan's comments regarding clause 79(b). The AER considers that the User's liability relating to overruns should necessarily be limited to unauthorised overruns. The AER considers **clause 79(c)** acceptable. The AER considers **clause 79(d)** acceptable. The AER considers that **clause 79(e)** is not reasonable on the basis that the "offering" of Off-Specification Gas for transportation would be unlikely to create a risk for the Service Provider (as distinct from the delivery of Off-Specification Gas which is covered in subclause (d)). The AER therefore requires deletion of this clause. In relation to **clause 79(f),** the AER notes the amendment above (inserting a new clause after clause 48) which requires a provision that sets out the Service Provider's obligation to deliver gas at a certain pressure. The AER requires an amendment to clause 79(f) that is consistent with the new inserted clause. With respect to Santos and Magellan's submission, the AER considers that as the earlier access arrangement did not extend liability for consequential loss to a failure to deliver gas at certain pressures in accordance with its obligations under that agreement, and given that no justification has been provided to support such a change, that the new clause (a) along with other of the amendments to clause 79 will be sufficient to address the perceived overall imbalance between the liability of the User and of the Service Provider. In particular, in line with the AER's required amendments to clause 80 regarding the liability cap, the AER considers that liability for consequential loss should extend to any acts or omissions	

	amounting to gross negligence or wilful misconduct by either the Service Provider or the User. This will ensure that the liability provisions are rebalanced. In addition, the AER also accepts the submission by Santos and Magellan to the extent that the Service Provider should be liable where it delivers off-specification gas to the delivery point. However, the AER has qualified this to the extent that such liability is due to the Service Provider's negligence or wilful default, an approach consistent with the Terms and Conditions of the earlier access arrangement. The AER requires the insertion of new subclauses to clause 79 to effect these additions. The AER accepts **clause 79(g)** subject to the required amendment to clause 81. The AER considers that only minor amendment to **clause 79(h)** is required in light of the amendments to clause 78. Those amendments sufficiently limit the scope of the User's liability with respect to the Information Interface. Further, with reference to the broad concerns raised by Users in relation to clause 79, the AER has reviewed the definition of "consequential loss" and considers that it extends beyond what is ordinarily contemplated as being within the boundaries of consequential loss. In particular, if loss is too remote it is generally not recoverable. Subclause (b) of the definition is problematic in this respect (and is to a certain extent covered by subclause (a)), and in addition it uses the term "consequential loss" so that it is unclear how this should be interpreted. Subclause (c) is also potentially broader than is generally understood and the AER considers that it is more appropriate that some of these terms ("bargain, opportunity or anticipating savings") are assessed under subclause (a). The AER therefore requires amendments to the definition. Regarding **clause 80**, the AER considers that Santos and Magellan's submission raises a valid concern that the absence of an amount of the monetary liability cap in the Terms and Conditions is problematic as the AER is unable to assess whether the cap is reasonable. The AER considers that the amount of the liability cap would need to be assessed against the overall contract value, as proposed by Santos and Magellan, but also against the liabilities of the service provider, and justified accordingly in order to establish its reasonableness. The AER considers that a figure could have been provided given that there is likely to be only one user of the pipeline. Further, NT Gas has offered no specific justification for inclusion of a cap. In the absence of a figure and justification, the AER considers the clause should be deleted. **Clause 81** provides that the user is to indemnify the Service Provider and its Related Body Corporate in certain circumstances. The AER agrees with Santos and Magellan that the indemnity referred to in **subclause 81(a)** is unreasonable. It is not appropriate for the User to indemnify the Servicer Provider for acts or omissions that are clearly beyond the User's control. The AER therefore requires deletion of this	

	subclause 81(a). **Clause 81(b)** provides that the User must indemnify the Service Provider in respect of any third party claim resulting from the User's acts or omissions. The AER considers this reasonable as such acts or omissions are within the control of the User. The AER also notes Santos and Magellan's submission that the indemnity should only cover actual losses and not extend to losses which a third party "claims to suffer". While it may be that these concerns relate to the need for step-in rights, it is not clear to the AER what Santos and Magellan are seeking or the justification for such a change. Therefore, no amendment is required. The AER notes Santos and Magellan's submission that the Service Provider should indemnify the User in the same way. In the previous Terms and Conditions, each party indemnified the other including in relation to the maintenance and operation of its properties and facilities and any claim or action arising out of them and in addition in respect of failure to perform or satisfy any of the provisions of the Services Agreement. NT Gas has offered no specific reasons as to why these indemnities have been removed. NT Gas has provided a general justification for the change in Terms and Conditions that these no longer correspond with NT Gas's and APA Group's gas transportation arrangements but it is not clear to the AER how this relates to the absence of indemnities provided by NT Gas. The AER notes that in the Roma to Brisbane Pipeline access arrangement each party (the User and the Service Provider) are required to indemnify the other for any loss arising out of its gross negligence or wilful misconduct.[604] The AER therefore considers that it would be appropriate for NT Gas to provide to the User the security of an indemnity in respect of the Service Providers' acts or omissions. The AER requires the insertion of a new clause that requires each Party to indemnify the other for any loss arising out of its gross negligence or wilful misconduct.	
Force majeure clause 82, 83, 84, 85, 86 and 87	NT Gas has proposed a definition of a Force Majeure Event in **clause 82** and has listed various events in subclauses (a) to (g) that are included in the definition. **Clause 83** sets out various events which are excluded from the definition. A Party's obligations are suspended during a Force Majeure Event to the extent set out in **clause 84**, however, such suspension does not relieve the User of certain obligations as set out in **clause 85**. A Force Majeure Event does not relieve either Party of liability in relation to certain circumstances covered in **clause 86**. **Clause 87** provides for termination as a result of a Force Majeure Event. Santos and Magellan have submitted that: ▪ the events listed in clause 82(g) should be two sided. If a breakdown of NT Gas's equipment constitutes a Force Majeure Event then it should also cover breakdown of the User's equipment	Delete the word 'reasonable' from chapeau to clause 82. Amend clause 82 (a) to read… acts of God, including without limitation, earthquakes, floods, washouts, landslides, lightning, storms and *other acts caused by* the elements; Amend clause 82(f) by deleting the words "any order or direction of any Authority" and "or the failure to obtain or maintain any necessary Approval" Amend clause 82 (g) by deleting the words "breakdown, loss or damage or the necessity to undertake alterations, repairs or maintenance (other than routine maintenance for which notice

	■ clause 83, by excluding listed events from the definition of a Force Majeure Event, will be of little benefit for a User and is contrary to the purpose of a Force Majeure clause. There is no justification for removing these events from the definition and they should be subject to the general Force Majeure Event test as set out at the beginning of clause 82 ■ with respect to clause 85 if the user is unable to accept gas as a result of an event beyond its control then the user should not be liable to pay the charges under the agreement. PWC submitted that a reduction in the Tolling Charge should be related to the inability of the Service Provider to transport Nominated quantities up to MDQ and not the Scheduled quantity. Otherwise, if the Service Provider is unable to schedule all gas nominated, it is able to reduce its transport obligation and the User is then obliged to maintain payment of tolls. The AER notes that the term **'***force majeure*' was defined in the previous Terms and Conditions as "…beyond the control" of a Party rather than "the reasonable control…" of a Party as is the case here. The AER understands that such an event is typically one over which a party to a contract has no control, for example, an event such as a cyclone. The AER notes that the qualifying phrase "that Party is not reasonably able to prevent or overcome" adds the necessary element of reasonableness to the test. The AER therefore requires that the word "reasonable" be deleted from clause 82. Further, NT Gas has proposed several events as constituting a Force Majeure Event provided they meet the general criteria in clause 82. The AER notes that the previous Terms and Conditions do not take this approach and the AER has reservations about the need to identify such events when the general criteria must be satisfied in any case. The words "provided that they meet the foregoing criteria" sufficiently address Santos and Magellan's second point in that each of the events must meet this general criteria and is not automatically deemed to be a force majeure event. Nonetheless, accepting this approach, the AER considers that only some, not all of the above events should be included and in addition, requires amendments to the drafting of some of the listed events in order to achieve greater clarity. In subclause (a), the AER considers that the drafting should be amended to improve clarity and therefore requires that it conclude: "and *other acts caused by* the elements;…" The AER considers that clauses 82(b), (c), (d) and (e) are acceptable. Regarding **clause 82(f),** the AER considers that while an omission or failure to act by any Authority might constitute a Force Majeure Event, the other aspects of this provision might ordinarily be within the control of either party to affect. The AER therefore requires their deletion. The AER considers that this deletion is	has not been given)." Amend clause 83 to read: "*Lack of finances and changes in market conditions for the transportation and purchase or sale of gas are not a Force Majeure Event.*" Amend clause 84 as follows: "Subject to certain exceptions *as specified under clause 85*, …". Amend clause 85 by deleting the current wording and replacing it with the following: '*Where there is a charge based on a Minimum Bill, Capacity Charge, Tolling Charge or MDQ, and the Service Provider is unable to perform its obligations under the Service Agreement due to an event of Force Majeure the charge will be based on the highest quantity of gas (up to the MDQ) available to be withdrawn during that period rather than MDQ. The ACQ specified in the Service Agreement will be adjusted to reflect the period during which the Service Provider was not able to deliver the quantity of gas nominated by the User.* Include definition of *Tolling Charge*

	necessary so that there can be no inferred presumption that such events are likely to be a Force Majeure Event even accepting that they must first meet the general criteria. Regarding **clause 82(g)**, the AER considers that this has the potential to remove liability for negligence on the part of the Service Provider in circumstances where the Servicer Provider has failed to maintain the Pipeline. The AER considers that it is the responsibility of the Service Provider to act to undertake alterations, repairs and maintenance and to avoid breakdowns and that any loss or damage associated with such actions are within the control of the Service Provider and would not meet the general criteria. Therefore, the scope of this clause should be limited to accidents only. Accordingly, the AER requires deletion of the following words: “breakdown, loss or damage or the necessity to undertake alterations, repairs or maintenance (other than routine maintenance for which notice has not been given)”. The AER notes that this does not mean that some breakdowns may not constitute a Force Majeure Event but should such an event occur, there will be no inferred presumption that it is a Force Majeure Event and the analysis of whether it is or not will depend entirely on whether it meets the general criteria. The AER considers that the above changes will sufficiently address the concern raised by Santos and Magellan as to the non-reciprocal nature of this clause and that it is not necessary to require reciprocity. Regarding **clause 83**, the AER agrees with Santos and Magellan’s submission that this clause is contrary to the purpose of a Force Majeure clause in that there is no reason why if the User’s inability to supply or consume is caused by a Force Majeure Event such as a cyclone that the User should not be able to rely on the Force Majeure clause. The AER therefore does not accept the clause in its entirety. Accordingly, the scope of the clause is to be limited to lack of finances and changed market conditions. The AER considers that **clause 84** requires amendment to reflect that the phrase “Subject to certain exceptions” is a reference to clause 85. The AER considers that this is necessary so that no confusion arises as to the meaning. Regarding clause 85, the AER requires the deletion of the phrase “among other things” as the meaning of the phrase is unclear and in the AER’s view, the obligations during suspension appear to be clearly set out as in clause 85 and clause 86(c). The AER notes the submissions made by Santos, Magellan and PWC in relation to **clause 85**. The AER considers that the reasonable course is for payment to be required in direct proportion to the highest quantity of gas available to be withdrawn, a situation that would reflect clause 28 of the Terms and Conditions in the earlier access arrangement. The AER considers it appropriate to include the wording from clause 28 of the earlier access arrangement at clause 85. The AER notes that no definition is provided for Minimum Bill and Capacity Charge (as previously	

	noted) and also that no definition is provided for Tolling Charge. The AER requires the inclusion of definitions for all these terms. The AER considers that clause 86 is acceptable. The AER considers that clause 87 is acceptable.	
Assignment clauses 88, 89, 90, 91 and 92	NT Gas has proposed that a party may assign the whole or part of its interest in the Transportation Agreement if the assignment is part of a corporate acquisition, merger or reorganisation (**clause 88**). The Service Provider may assign its interests to another person who owns the pipeline (**clause 89**) and a party may assign the whole or part of its interests if the assigning party remains bound by the Transportation Agreement (**clause 90**). Any other assignment requires the consent of the other party (**clause 91**). NT Gas has further proposed that any assignment permitted will be conditional on the execution by the assignee in a form that is satisfactory to the non-assigning party acting reasonably (**clause 92**). The AER considers that clauses. 88, 89, 90, 91 and 92 are acceptable.	No amendments
Confidentiality clause 93, 94 and 95	NT Gas has proposed that a party receiving Confidential Information may use it solely for the purpose of performing its obligations under the Transportation Agreement or for internal purposes related to corporate governance (**clause 93**). Under **clause 94** a party must obtain the prior written consent of the other party in order to use or disclose Confidential Information for any other purpose, subject to certain specific circumstances where consent is not required (such as if disclosure is required by law). If in such circumstances NT Gas has proposed that the disclosing party may still be required to notify the other party of the intended disclosure and to obtain a confidential undertaking from the third party (**clause 95**). Santos and Magellan have submitted that given the sensitivity of gas volumes, and the fact that NT Gas has various related entities acting in different roles, these obligations of confidentiality should be clear, and specifically: ▪ clause 93 should be amended to clarify the meaning of 'internal purposes related to the governance of the Party or its Related Bodies Corporate.' ▪ clause 95 should be amended to specify when a disclosing party will be required to notify the other party and/or obtain a confidentiality agreement from a third party. The AER considers that **clauses 93, 94 and 95** are not consistent with the requirements under Part 16 of the NGR which sets out a service provider's obligations concerning confidentiality. Of note is	Amend clause 93 as follows: *"The User may use Confidential Information solely for the purposes of performing its obligations under the Transportation Agreement."* Amend clause 94 as follows: "…for any other purpose *except where* disclosure is required by law or lawfully required by an Authority or if the information..." Delete clause 95. Insert new clause: *"The Service Provider must comply with any confidentiality requirements imposed on it pursuant to the National Gas Law and the National Gas Rules (Part 16)."*

	rule 137(1)(b) of the NGR which sets out that a scheme pipeline service provider must not use relevant confidential information for a purpose other than the purpose for which the information was given to the service provider. Given these obligations, the AER requires that these clauses 93, 94 and 95 be amended so as to apply to the User only and that an additional clause be included to address the Service Provider's specific obligations under the NGL and NGR. The AER also agrees with Santos and Magellan that clause 93 is unclear as to the meaning of internal governance purposes and is potentially too broad as a result. The AER therefore requires the deletion of this part of clause 93. The AER also considers that clause 94 regarding disclosure is uncertain in scope and requires amendments to clarify the scope. In addition, the AER agrees that clause 95 is unclear as to the circumstances that would require the User to notify the other Party of an intended disclosure in circumstances where consent is not required. The AER requires that clause 95 be deleted.	

D. Submissions

The AER received submissions on N.T. Gas's proposal from the following entities:

- Northern Territory Major Energy Users
- Santos Limited and Magellan Petroleum Australia Limited
- Power and Water Corporation
- Northern Territory Treasury

Glossary

AAG	access arrangement guideline
ABS	Australian Bureau of Statistics
Access Economics	Access Economics Pty Ltd
ACG	Allen Consulting Group
ACIL Tasman	ACIL Tasman Pty Ltd
ActewAGL	ActewAGL Distribution
APA	APA Group
APT Allgas	APT Allgas Energy Pty Limited
ATO	Australian Taxation Office
AWOTE	average weekly ordinary time earnings
Capex	capital expenditure
CAPM	capital asset pricing model
CEG	Competition Economics Group
CGS	Commonwealth Government Securities
DCVG	direct current voltage gradient
EBA	enterprise bargaining agreement
EGW	electricity, gas and water
Envestra	Envestra Limited
GDP	gross domestic product
GFC	global financial crisis
GJ	gigajoules (equal to 1 000 000 000 joules)
ISR	industrial special risk
IT	information technology
LPI	Labour price index
MDQ	maximum daily quantity
MRP	market risk premium
NER	National Electricity Rules

NT	Northern Territory
NTMEU	Northern Territory Major Energy Users
NT Treasury	Northern Territory Treasury
O&M	operating and maintenance expenditure
opex	operating expenditure
PTRM	post-taxation revenue model
PWC	Power and Water Corporation
QLD	Queensland
RBA	Reserve Bank of Australia
Santos and Magellan	Santos Limited and Magellan Petroleum Australia Limited
SCADA	supervisory control and data acquisition
SFG	Strategic Finance Group Consulting
STTM	short term trading market
TJ	terajoules (equal to 1000 gigajoules)
Tribunal	Australian Competition Tribunal
UBS	Union Bank of Switzerland
WACC	weighted average cost of capital
Wilson Cook	Wilson Cook & Co.