Draft Decision

APT Allgas

Access arrangement proposal for the Qld gas network

1 July 2011 – 30 June 2016

February 2011

AUSTRALIAN ENERGY REGULATOR

Request for submissions

This document sets out the Australian Energy Regulator's (AER) draft decision for APT Allgas Energy Limited's (APT Allgas) access arrangement proposal for the period 1 July 2011 to 30 June 2016.

The AER will hold a forum on its draft decision for APT Allgas on 1 March 2011 in Brisbane. At this forum the AER will outline the reasons for its draft decision and provide an opportunity for questions or comments from interested parties.

This draft decision requires APT Allgas to revise its access arrangement proposal. APT Allgas must submit a revised access arrangement proposal responding to the AER's draft decision by 23 March 2011.

Interested parties are invited to make written submissions on issues regarding the draft decision, consultants' reports and revised access arrangement proposal to the AER by 21 April 2011. The AER will consider all information it receives in the access arrangement review process in accordance with the ACCC/AER information policy. The policy is available at www.aer.gov.au.

Submissions can be sent electronically to qldsagas@aer.gov.au.

Alternatively, submissions can be mailed to:

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

The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non–confidential version of the submission.

All non-confidential submissions will be placed on the AER website. Copies of APT Allgas's access arrangement proposal, 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 qldsagas@aer.gov.au.

Contents

Draft decision

The AER does not propose to approve APT Allgas's access arrangement proposal as it is not satisfied that it meets the requirements specified in the NGR.[1] The draft decision sets out the reasons for this decision.[2]

This decision also outlines the amendments (or nature of amendments)[3] required to be made to the access arrangement proposal[4] or access arrangement information[5] 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.[6]

1 NGR, r. 41 and r. 100.
2 NGR, r. 59(4).
3 NGR, r. 43(3) and r. 59(2).
4 APT Allgas, *Access arrangement – 01 July 2011 – 30 June 2016*, 30 September 2010.
5 APT Allgas, *Access arrangement information – 01 July 2011 – 30 June 2016*, 30 September 2010.
6 NGR, r. 100.

Shortened forms

Shortened form	Extended form
access arrangement information	APT Allgas, *Access arrangement information – 01 July 2011 – 30 June 2016*, 30 September 2010
access arrangement period	1 July 2011 to 30 June 2016
access arrangement proposal	APT Allgas, *Access arrangement – 01 July 2011 – 30 June 2016*, 30 September 2010
AER	Australian Energy Regulator
capex	capital expenditure
Code	National Third Party Access Code for Natural Gas Pipeline Systems
CPI	consumer price index
earlier access arrangement	Access arrangement for 1 July 2006 to 30 June 2011 inclusive
earlier access arrangement period	1 July 2006 to 30 June 2011
NGL	National Gas Law
NGR	National Gas Rules
opex	operating expenditure
QCA	Queensland Competition Authority

Overview

APT Allgas owns and operates gas distribution pipelines in Queensland and northern New South Wales that supply natural gas to customers in Brisbane (south of the river), and in other regional centres including Toowoomba and the Gold Coast. In total around 79 000 residential, 4900 small business and 100 large demand customers are serviced by the network. The network is a natural monopoly and is regulated by the AER to ensure that APT Allgas does not charge excessive prices or impose unduly onerous terms and conditions on customers.

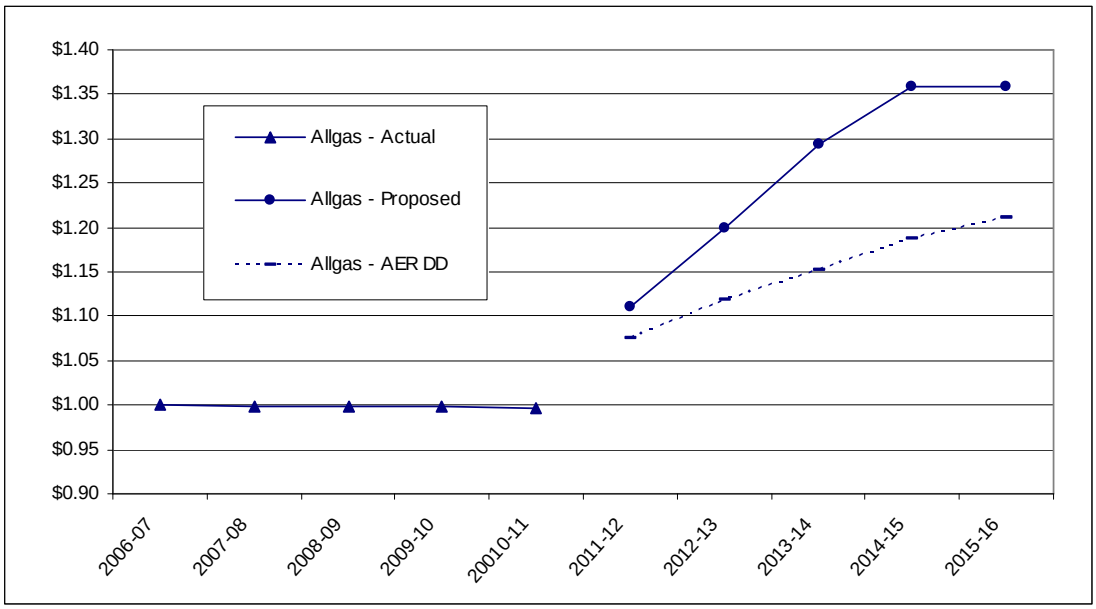
Under the regulatory framework— which is set out in legislation— APT Allgas first lodges a proposed access arrangement with the AER that sets out its proposed tariffs and terms and conditions. The AER then reviews the proposal and decides whether it is acceptable, or whether amendments are required to make the proposal acceptable in accordance with the National Gas Rules (NGR) and National Gas Law (NGL).

Overall, the AER has come to the view that APT Allgas's access arrangement proposal is not acceptable because the proposed tariffs are too high and the terms and conditions are too much in favour of APT Allgas. As a result, the AER is requiring APT Allgas to lower its proposed prices and amend its terms and conditions. However, the AER is of the view that some price increases are warranted so that APT Allgas 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. The draft decision should be read in conjunction with APT Allgas's access arrangement proposal and the AER's consultants' reports, which are available on the AER's website.

Proposed tariffs

APT Allgas's proposed tariffs (indexed) are shown in figure 1 along with the tariffs that the AER has calculated in this draft decision. The tariffs are calculated based on forecasts of required capital expenditure for new pipeline assets as the network grows, the replacement of existing assets as needed, the costs of capital and the cost of operating APT Allgas's business. In addition, the tariffs reflect forecasts of demand on the network over the next five years. This draft decision sets out the AER's considerations and own forecast of each of these cost components.

Figure 1: Real price index – haulage tariffs (index price starts at $1 for 2005-06)

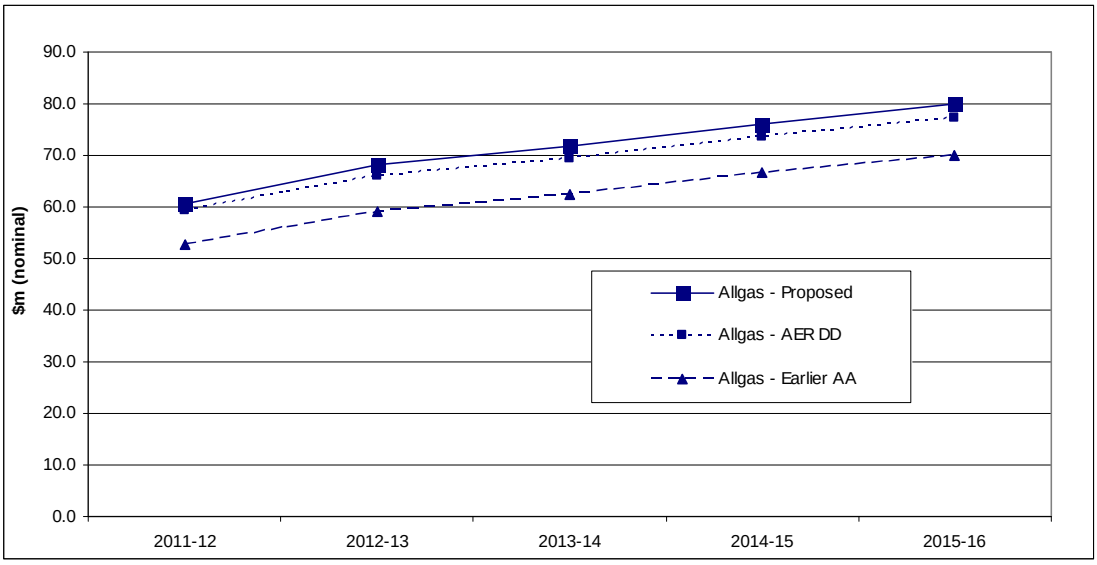


The tariff increases proposed by APT Allgas for the access arrangement period are clearly higher than applied over the earlier access arrangement period. These increases are driven by several factors, with the main causes being higher financing costs and a significant increase in forecast customer requested capital expenditure. APT Allgas also revised it asset lives. As well, operating costs are expected to rise by around 22 per cent compared to costs over the current period due to higher labour costs and other factors. These issues are discussed in more detail below and in the relevant chapters of this draft decision.

Cost of capital

APT Allgas's proposed cost of capital of 10.3 per cent, compared with its lower cost of capital in the earlier access arrangement period of 8.75 per cent, increases APT Allgas's estimated revenue requirement by 13 per cent over the access arrangement period. The AER does not accept the cost of capital proposed by APT Allgas and has instead estimated it to be 9.96 per cent. This estimate would still account for an increase in the revenue requirement of 11 per cent over the access arrangement period. The higher cost of capital will be the major driver of real tariff increases over the access arrangement period. Figure 2 shows APT Allgas's revenue (including ancillary services revenues) in the access arrangement period under a number of cost of capital scenarios.

Figure 2: APT Allgas's forecast revenue under different cost of capital scenarios



The parameters used to calculate the cost of capital by APT Allgas and the AER are shown in table 1.

Table 1: APT Allgas's proposed; and AER's allowed cost of capital parameters

Parameters	APT Allgas proposal	AER draft decision
Nominal risk free rate	5.07	5.68
Inflation forecast	2.50	2.52
Real risk free rate	2.51	3.08
Cost of debt[7]	8.69	9.61
Debt risk premium	3.39	3.93
Cost of equity	13.02	10.48
Equity beta	1.1	0.8
Market risk premium	6.5	6.0
Gearing	60	60
Nominal cost of capital	**10.64**	**9.96**

The AER considers that the parameters estimated by APT Allgas do not meet the requirements of the NGR. In addition, the AER does not consider the proposed approach of calculating the cost of equity meets the requirements of the NGR.

Capital expenditure

APT Allgas has forecast capital expenditure of $129 million over the access arrangement period, representing a real increase of 5 per cent over the earlier access arrangement period. Over 60 per cent of this proposed capital expenditure is in the

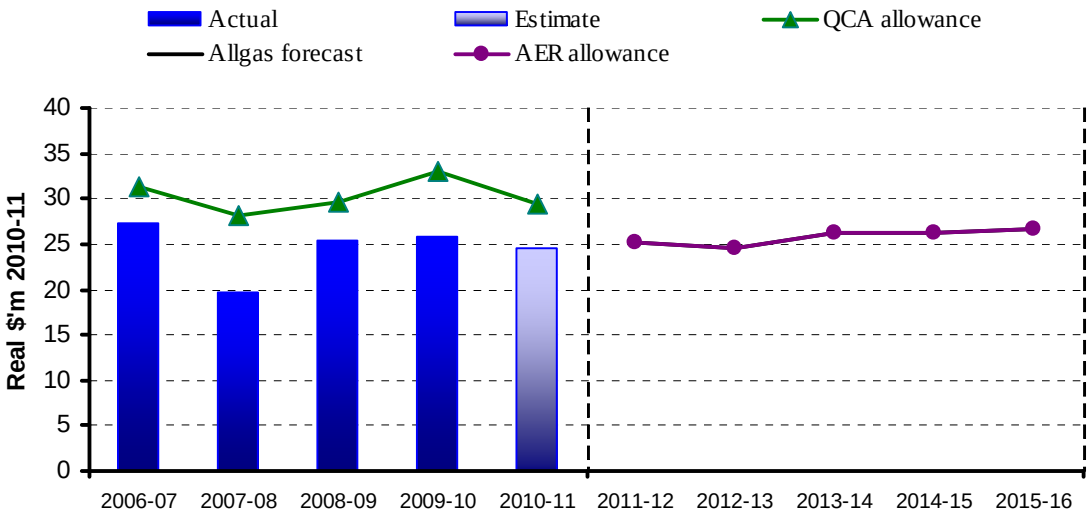
[7] APT Allgas proposed to include debt raising costs in the cost of debt, as per previous state regulator practise. However, the AER's preferred practice is to separate debt raising costs from the overall cost of debt.

'customer requested' category, which is consistent with its share of total capital expenditure in the previous access arrangement period.

APT Allgas has proposed approximately $80 million of customer requested capital expenditure, an increase of 16 per cent on the earlier access arrangement period. The forecast rate of customer requested capital expenditure is closely related to projections of growth in customer numbers. The program itself is comprised of expenditure on mains, meters and services. Considering the advice of Wilson Cook, who were engaged by the AER to provide expert technical advice, the AER accepts that APT Allgas's projected customer requested capital expenditure is prudent and efficient.

The AER did not agree with some elements of the remainder of APT Allgas's capital expenditure program, in particular APT Allgas's estimates for contingency allowances, overheads and real cost escalators. The AER, however, did not consider that this difference ($3.9 million) is large enough to require APT Allgas to amend its proposed capital expenditure. Figure 3 shows APT Allgas's proposed and approved capital expenditure programs for the earlier access arrangement period and access arrangement period.

Figure 3: Total capex – APT Allgas proposed and AER allowed



Operating expenditure

APT Allgas has forecast operating expenditure of $102 million over the access arrangement period, representing a real increase of 23 per cent on the previous period. According to APT Allgas, this increase was driven by expected changes in input costs, unaccounted for gas (UAG) and the need for various types of non-base year costs to cover circumstances not reflected in the earlier access arrangement period.

The AER does not consider APT Allgas's forecast operating costs are prudent and efficient and the lowest sustainable cost of managing its network, as the NGR requires. The AER:

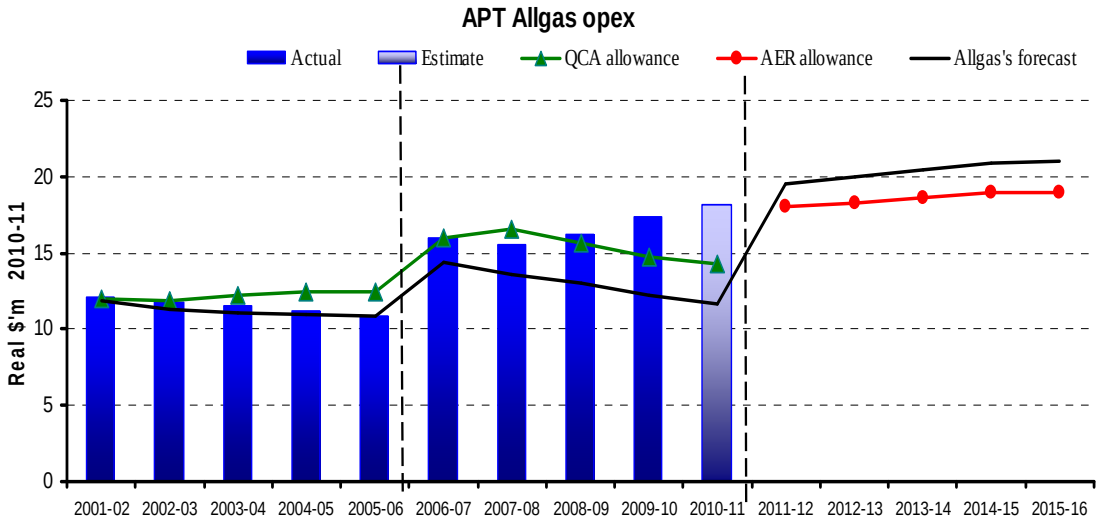
- has estimated real labour and material cost escalators that are lower than those forecast by APT Allgas, based on its own analysis and advice from Wilson Cook and Access Economics

- does not consider APT Allgas sufficiently justified the inclusion of a margin on forecast UAG prices, and has amended the UAG prices to remove this margin

- does not accept a number of APT Allgas's step changes on the basis that these are not consistent with the requirements of the NGR.

The adjustment made by the AER to APT Allgas's forecast operating costs results in a real increase of 12 per cent on actual expenditure over the access arrangement period, compared to the 23 per cent increase forecast by APT Allgas. The lower levels of opex accepted by the AER are evenly spread over the access arrangement period, as shown in figure 4.

Figure 4: Total opex – APT Allgas proposed and AER allowed

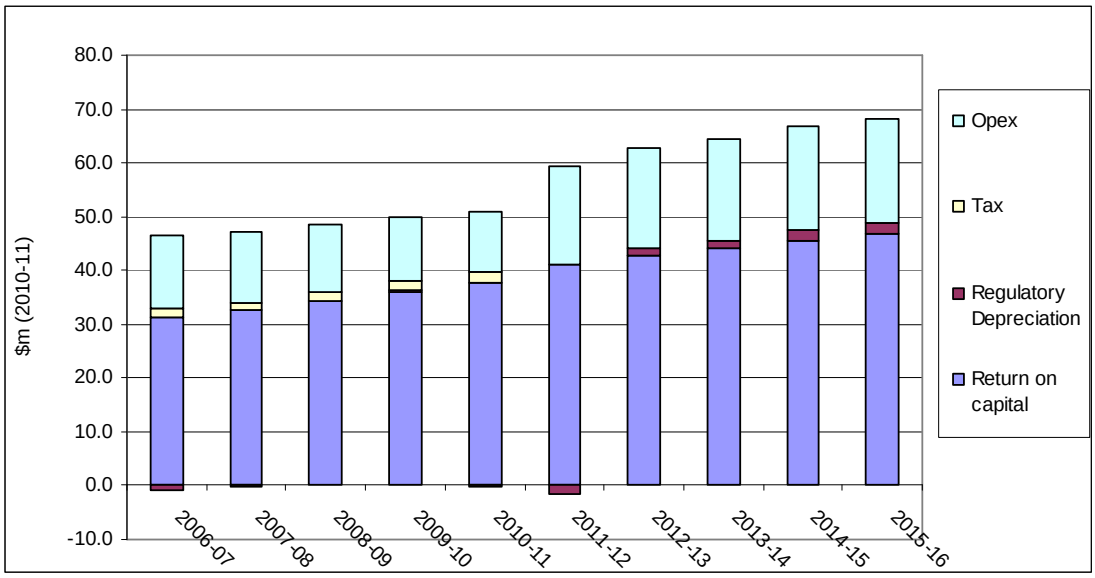


Revenue requirement

Once the capital base on 1 July 2011 has been determined, the revenue requirement for the access arrangement period can be calculated. The AER does not accept the depreciation amounts used by APT Allgas to roll forward its capital base to 1 July 2011. In particular, errors were found in the actual inflation rates used to adjust the forecast depreciation amounts. After adjusting for these issues, the AER has determined the capital base to be $424 million on 1 July 2011. This is a 0.5 per cent increase from APT Allgas's proposed capital base of $422 million.

The AER's forecast revenue requirement is based on forecast capital and operating expenditure considered to be prudent and efficient, forecast depreciation, forecast inflation, a provision for tax and the return on capital. The AER has calculated APT Allgas's revenue requirement (including ancillary services revenues) over the forecast period to be $346 million (nominal), a real increase of 32 per cent over the earlier access arrangement period. This compares to APT Allgas's forecast revenue requirement of $372 million (nominal), a real increase of 42 per cent. The forecast revenue requirement is shown in figure 5.

Figure 5: AER's approved revenue requirement for APT Allgas (including ancillary services)



The AER does not accept a number of individual components that determine APT Allgas's total tax allowance. In particular, the AER has estimated that a gamma value of 0.45 is appropriate, compared to APT Allgas's proposal of 0.2. The AER also did not accept APT Allgas's approach to the treatment of capitalised overheads for taxation purposes. The expensing of these overheads for tax purposes resulted in zero tax allowance being determined for APT Allgas for the access arrangement period.

The AER has accepted adjustments to the remaining lives of existing assets that APT Allgas proposed. The impact of the shortened asset lives is indicated in figure 7 by regulatory depreciation during the access arrangement period being much greater than in the earlier access arrangement period. Regulatory depreciation is the sum of straight-line depreciation and the negative depreciation associated with indexation of the capital base. In the earlier access arrangement period the indexation effect dominated and regulatory depreciation overall was therefore negative.

Other Issues

APT Allgas proposed a single general cost pass through event, for which two separate materiality thresholds apply in different circumstances. The AER does not accept the general event, or either of the materiality thresholds, on the basis that they do not provide the appropriate level of risk sharing between APT Allgas and its customers. The AER instead applied a framework of defined cost pass through events, with a materiality threshold of 1 per cent of revenue per event.

The AER accepted APT Allgas's general approach to forecasting customer demand. However, the AER considered it necessary to amend specific forecast elements, resulting in an upward revision to residential demand forecasts in the Western region, and a downward revision to business volume customers. The AER's draft decision provides for forecast residential demand which is, on average, 6 per cent higher than forecast by APT Allgas.

Terms and conditions

APT Allgas's access arrangement sets out the proposed terms and conditions that are not directly related to the nature or level of tariffs paid by users. Some of the terms and conditions vary from those included in the earlier access arrangement. The AER has not accepted a number of the terms and conditions of APT Allgas's access arrangement proposal and requires them to be amended. The AER considers that amended provisions for these terms and conditions better promote the national gas objective in s. 23 of the NGL, which the AER considers requires it to balance the interests of the service provider and users.

Background

The AER is responsible for the economic regulation of covered natural gas distribution pipelines in all states and territories (except WA). The AER's functions and powers are set out in the NGL and the 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 distribution pipelines.

On 1 October 2010, APT Allgas submitted an access arrangement proposal for its Queensland gas distribution network for the period 1 July 2011 to 30 June 2016. In accordance with the NGR, the AER published APT Allgas's access arrangement proposal on 21 October 2010. Interested parties were invited to make submissions on the proposal and two submissions were received. APT Allgas also presented its access arrangement proposal at a public forum held in Brisbane on 28 October 2010.

1 Introduction

1.1 Background

APT Allgas Energy Pty Limited (APT Allgas) is wholly owned by APT Pipelines Limited, part of the publicly listed APA Group. APT Allgas is both owner and operator of the APT Allgas network.[8]

1.2 APT Allgas's network

The APT Allgas network comprises 2942 km of pipeline delivering 10.5 PJ of gas annually to approximately 82 000 customers. The network is separated into three operating regions: Brisbane (covering the area south of the Brisbane River), the Western region (including Toowoomba and Oakey) and the South Coast region (covering the Gold Coast, Tweed Heads and Banora Point in north east NSW). The assets used to service Brisbane constitute the majority (58 per cent) of the network.[9]

1.3 Regulatory requirements

The Australian Energy Regulator (AER) is responsible for the economic regulation of covered natural gas distribution pipelines in all states and territories (except WA). The APT Allgas distribution network is a covered pipeline.[10] The AER's functions and powers are set out in the National Gas Law (NGL) and the National Gas Rules (NGR).

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:[11]

> ... 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 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.[12]

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8 APT Allgas, *Access arrangement submission*, September 2010, p. 6.
9 APT Allgas, *Access arrangement submission*, September 2010, pp. 6–9.
10 AEMC, *List of natural gas pipelines*, viewed 9 December 2010, <http://www.aemc.gov.au/Gas/Scheme-Register/Pipeline-list-summary.html>.
11 NGL, s. 23.
12 NGL, s. 28. The revenue and pricing principles are set out in NGL, s. 24.

1.3.2 National Gas Rules

The NGR sets out the provisions the AER must apply in exercising its regulatory functions and powers, including prescribing the AER's discretion in making the draft decision on APT Allgas's access arrangement proposal.

In assessing APT Allgas's access arrangement proposal, the AER:

- has no discretion in respect of r. 50(2) (review submission and revision commencement dates)
- has limited discretion in respect of r. 79 (capital expenditure criteria), r. 89 (depreciation criteria), r. 91 (operating expenditure criteria) and r. 94 (tariffs)
- has full discretion in all other cases.

APT Allgas's access arrangement for 1 July 2006 to 30 June 2011 inclusive 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 APT Allgas's access arrangement proposal for the period 1 July 2011 to 30 June 2016.

1.4 Structure of draft decision

The AER's consideration of APT Allgas's access arrangement proposal and accompanying access arrangement information is set out as follows:

- Introductory chapters outline the regulatory environment, network description 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 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

The AER has scheduled a forum on the draft decision for 1 March 2011 in Brisbane. The AER will use this forum to explain the draft decision to interested parties and to obtain comments from interested parties.

APT Allgas may submit a revised access arrangement proposal and updated access arrangement information to the AER by 23 March 2011. Submissions on the AER's draft decision and APT Allgas's revised access arrangement proposal from interested parties are due by 21 April 2011.

The AER expects to make a final decision in late May or early June 2011.

2 Pipeline services

APT Allgas'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 APT Allgas has identified the pipeline to which the access arrangement relates and described the proposed pipeline services in accordance with the requirements of the NGR. However, the AER is not satisfied that APT Allgas's proposal to exclude the relighting of appliances from the definition of the inlet reconnection service is in the long term interests of consumers.

Further discussion of the specified reference services and tariffs proposed by APT Allgas is provided in chapter 10 of this draft decision.

2.1 Introduction

This chapter considers the pipeline services set out in APT Allgas'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.[13] Reference services are defined as pipeline services that are likely to be sought by a significant part of the market.[14] 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[15]
- describe the pipeline services the service provider proposes to offer to provide by means of the pipeline[16]
- specify the reference services, and the reference tariff for each reference service.[17]

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

APT Allgas has proposed to offer two haulage reference services, three reference ancillary services, and non-reference ancillary services (also called negotiated services) in the access arrangement period.[18] The proposed services are the same as

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13 NGL, s. 2.
14 NGR, r. 101(2).
15 NGR, r. 48(1)(a).
16 NGR, r. 48(1)(b).
17 NGR, r. 48(1)(c) and r. 48(1)(d).
18 APT Allgas, *Access arrangement proposal*, September 2010, pp. 4–7.

those provided in the earlier access arrangement period. The definition of the demand customer service includes customers with a daily demand of 50 GJ in addition to customers with an annual demand of 10 TJ per year.[19] The pipeline services proposed by APT Allgas are set out in table 1 below.

Table 1: APT Allgas's proposed pipeline services

Type of service	Title	Description
Haulage reference services	Volume customer service	Available where the end user is reasonably expected to withdraw a quantity of gas less than 10TJ per year and less than 50GJ per day
	Demand customer service	Available where the end user is reasonably expected to withdraw a quantity of gas more than 10TJ per year or 50GJ per day
Reference ancillary services	Special meter reading	A meter reading at the request of a user which is not a scheduled meter reading
	Inlet disconnection	The physical disconnection of pipework joining a delivery point to the network
	Inlet reconnection	Physical reconnection of a delivery point
Non-reference services	Additional services	Services other than reference services, for which terms and conditions may be negotiated

Source: APT Allgas, *Access arrangement proposal*, September 2010, pp. 5–7.

2.4 Submissions

The AER received a submission from AGL on the definitions of the specified pipeline services.[20] The issues raised in this submission regarding haulage reference services are considered in the reference tariff chapter (chapter 10) of this draft decision. In relation to reference ancillary services, AGL submitted that APT Allgas should reconsider its proposal to exclude the relighting of appliances from the definition of an inlet reconnection service given safety concerns surrounding customers attempting to relight appliances.[21]

2.5 AER's consideration

APT Allgas has correctly identified the pipeline to which the access arrangement relates. APT Allgas has included a reference to a website at which a description of the pipeline can be inspected.[22] The AER therefore considers that APT Allgas's access arrangement proposal meets the requirements of r. 48(1)(a) of the NGR.

APT Allgas has described the services which it proposes to offer to provide by means of the pipeline in section two of its proposed access arrangement.[23] The AER

19 APT Allgas, *Access arrangement submission*, September 2010, p. 12.
20 AGL, *APT Allgas's access arrangement proposal*, November 2010.
21 AGL, *APT Allgas's access arrangement proposal*, November 2010, pp. 1 and 3.
22 APT Allgas, *Access arrangement proposal*, September 2010, p. 1.
23 APT Allgas, *Access arrangement proposal*, September 2010, pp. 4–7.

therefore considers that APT Allgas's access arrangement proposal meets the requirements of r. 48(1)(b) of the NGR.

The haulage reference services and reference ancillary services proposed by APT Allgas are likely to be sought by a significant part of the market. These are essentially the same as the services sought by users in the earlier access arrangement period.

The AER shares the safety concerns raised by AGL regarding the proposed change to the definition of the inlet reconnection service to exclude the relighting of appliances at reconnected premises.[24] APT Allgas has provided no justification for the proposed change to the inlet reconnection service. The AER considers the inlet reconnection service as specified in the earlier access arrangement period is a preferable alternative, which better meets the national gas objective for the long term interests of consumers of natural gas with respect to safety.

The AER has no information before it to suggest that the proposed non-reference services are likely to be sought by a significant part of the market. The AER therefore considers that APT Allgas's access arrangement proposal is consistent with the requirements of r. 101(2) of the NGR.

Consistent with the earlier access arrangement, APT Allgas has proposed that data on metered volumes will be provided as part of each haulage reference service. However, to the extent practicable and reasonable APT Allgas will provide separate tariffs for elements of any service if requested by a user.[25] The AER therefore considers that APT Allgas's access arrangement proposal meets the requirements of r. 109(1) of the NGR.

2.6 Conclusion

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

However, the AER does not consider APT Allgas has appropriately specified the reference services as required under r. 48(1)(c). The AER considers a preferable alternative to the specified inlet reconnection service exists which better meets the national gas objective.

2.7 Required amendments

Before the access arrangement proposal can be approved, the AER requires the following amendment:

Amendment 2.1: Amend the access arrangement proposal to include, as part of the inlet reconnection service, the relighting of appliances installed at the place or premises to which gas is delivered.

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[24] AGL, *APT Allgas's access arrangement proposal*, November 2010, pp. 1 and 3.
[25] APT Allgas, *Access arrangement proposal*, September 2010, p. 4.

Part A – Total revenue (building block components)

3 Capital base

APT Allgas proposed an opening capital base on 1 July 2011 of $422 million ($ nominal). The AER considered that most elements of APT Allgas's proposed opening capital base were in accordance with the NGR. However, the AER required APT Allgas to make changes to the amounts calculated for depreciation and indexation and consequently accepted an opening capital base value of $424 million ($ nominal).

APT Allgas has forecast $129 million ($2010–11) in capex over the access arrangement period. The AER estimated the cost of APT Allgas's capex program to be $125 million ($2010–11) with the variance due to APT Allgas's estimates for contingency allowances, overheads and real cost escalation. However, the AER considers that this difference ($3.9 million ($2010–11)) is not large enough to require APT Allgas to amend its capex proposal. The AER accepts that the process for estimating capex is not necessarily an exact process and that there is some degree of imprecision in estimating capex.

Over 60 per cent of APT Allgas's proposed capex was in the customer requested category. A further 23 per cent of APT Allgas's proposed capex was in the network renewal category. The AER has calculated a closing capital base on 30 June 2016 of $562 million ($ nominal). Differences to the closing capital base proposed by APT Allgas are due to differences in the approach to calculating forecast deprecation and indexation.

3.1 Introduction

This chapter sets out the AER's consideration of the capital base and forecast capex proposed by APT Allgas for the access arrangement period.

3.2 Regulatory requirements

In assessing APT Allgas'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 capex (new facilities investment) under s. 8.21 of the Code.

In relation to the opening and projected capital base, the NGR requires APT Allgas to demonstrate:

- capex (by asset class) over the earlier access arrangement period (72(1)(a)(i) of the NGR)
- how the capital base is arrived at including a demonstration of how it is increased or diminished over the previous access arrangement period (72(1)(b) of the NGR)
- 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

- a forecast of conforming capex (r. 72(1)(c)(i) of the NGR) and depreciation over the access arrangement period, including a demonstration of how it is derived (r. 72(1)(c)(ii) of the NGR)

- the projected capital base is derived using the formula (opening capital base plus forecast conforming capex less forecast depreciation and disposed pipeline assets) in r. 78 of the NGR

- forecast capex is such as would be incurred by a prudent service provider (r. 79(1)(a) of the NGR)

- forecast capex is justifiable on a ground stated in r. 79(2) of the NGR. Such as, where the overall economic value is positive, or that either the expenditure is necessary to maintain and improve the safety of services or to comply with a regulatory obligation or meet levels of demand for services existing at the time the capex is incurred.

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.

Rule 85(1) of the NGR 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 APT Allgas to show the key expenditure performance indicators to be used to support the expenditure to be incurred over the access arrangement period (r. 72(1)(f) of the NGR).

3.3 Access arrangement proposal

3.3.1 Opening capital base

APT Allgas has proposed an opening capital base of $422 million ($ nominal). The calculation of this opening capital base is shown in table 3.1.

Table 3.1: APT Allgas's opening capital base ($m, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12
Opening capital base	302.7	326.0	350.5	370.2	396.2	421.7
Add capex[a]	25.2	19.3	25.0	26.4	26.4	
Add speculative capex	0.0	0.0	0.0	0.0	0.0	
Add re-used redundant assets	0.0	0.0	0.0	0.0	0.0	
Add indexation	6.3	14.7	5.1	11.3	11.0	
Less depreciation	8.1	9.5	10.4	11.4	11.9	
Less redundant assets	0.0	0.0	0.0	0.0	0.0	
Less disposals and transfers	0.0	0.0	0.05	0.2	0.0	
Closing capital base	326.0	350.5	370.2	396.2	421.7	

Source: APT Allgas, *Access arrangement submission*, September 2010, pp. 60–61.
(a) Includes capital contributions.

3.3.1.1 Capital expenditure in the earlier access arrangement period

APT Allgas has proposed to include conforming capex of $123 million ($2010–11) incurred in the earlier access arrangement period, 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.[1]

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

	2006–07	2007–08	2008–09	2009–10	2010–11	Total
Forecast (QCA approved)	31.2	28.2	29.7	33.0	29.5	151.5
Actual	27.3	19.8	25.4	25.9	24.6[b]	122.9
Difference	-3.9	-8.4	-4.3	-7.1	-4.8	-28.6

Source: APT Allgas, *Access arrangement submission*, September 2010, p. 39.
(a) The AER has converted nominal dollars to 2010–11 real dollars.
(b) Estimated expenditure.

APT Allgas submitted a report by Parsons Brinckerhoff (PB) to support its capex for the earlier access arrangement period.[2] The PB report concluded that the justifications provided by APT Allgas for the variation in capital expenditures are prudent and that the methodology followed in forecasting the project budgets and its subsequent

1 APT Allgas, *Access arrangement information*, September 2010, p. 111.
2 APT Allgas, *Access arrangement submission*, September 2010, attachment 4-5 (confidential).

implementation in the earlier access arrangement period is as would be incurred by a prudent operator acting efficiently as specified in r. 79(1)(a).[3]

APT Allgas's proposed capex for the earlier access arrangement period, including approved pass throughs, to be added to the opening capital base represents an underspend of approximately $29 million ($2010-11) or 19 per cent less than the capex approved by the QCA (see figure 3.1).[4]

Figure 3.1: Comparison of approved and actual/estimated capital expenditure by APT Allgas 2006-07 to 2010-11 ($m, 2010–11)

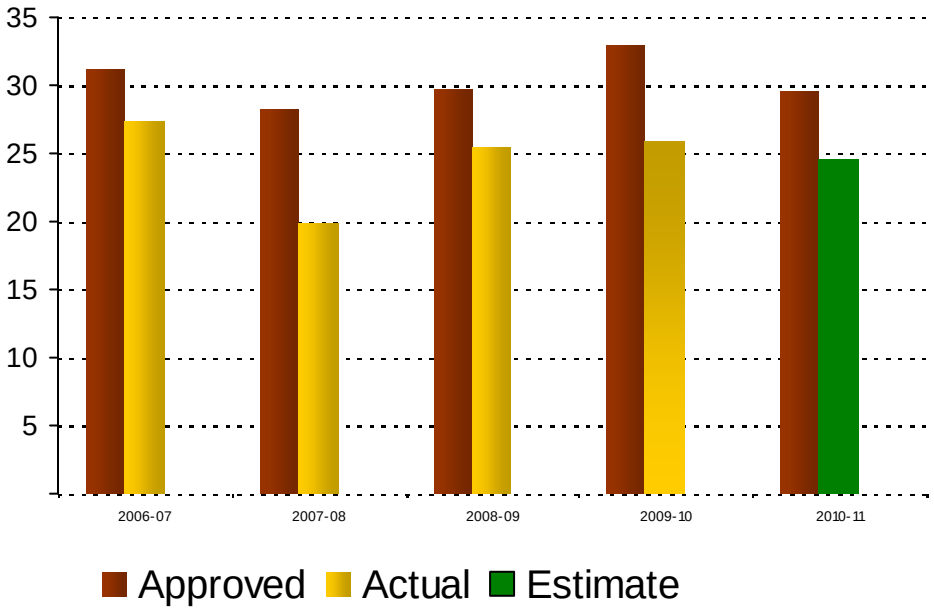

Table 3.3 shows APT Allgas's approved and incurred capex for the major capex categories for the earlier access arrangement period. During this period there was significant under-expenditure in the customer requested, network augmentation and non–system capex categories. APT Allgas's expenditure on network renewal was also lower than that approved by the QCA in 2006–07 and 2007–08, however, its expenditure in this category was on average 39.4 per cent higher than that approved by the QCA in the last three years of the previous access arrangement.

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3 APT Allgas, *Access arrangement submission*, September 2010, attachment 4-5, p. 13 (confidential).

4 APT Allgas, *Access arrangement information*, September 2010, p. 39.

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

		2006–07	2007–08	2008–09	2009–10	2010–11	Total
Customer requested	Allowed	14.4	15.2	16.4	17.2	19.4	82.7
	Incurred	14.4	14.9	14.3	12.5	13.2	69.3
	Variance (%)	0.0	-2.6	-12.8	-27.3	-31.8	-16.2
Network augmentation	Allowed	1.7	2.7	3.1	5.7	0.1	13.2
	Incurred	2.4	0.4	0.5	2.5	0.8	6.7
	Variance (%)	41.2	-83.3	-82.3	-55.4	800.0	-49.4
Network renewal	Allowed	7.3	7.0	7.0	6.8	6.7	34.9
	Incurred	4.0	2.3	9.0	9.9	9.7	34.9
	Variance (%)	-45.2	-67.1	29.1	45.6	43.5	0.0
Non-system	Allowed	7.8	3.2	3.2	3.2	3.2	20.7
	Incurred	6.5	2.2	1.6	0.8	0.9	12.0
	Variance (%)	-16.7	-32.6	-52.0	-74.0	-71.2	-42.0
Total capex	**Allowed**	31.2	28.2	29.7	33.0	29.5	151.5
	Incurred	27.3	19.8	25.4	25.9	24.6	122.9
	Variance (%)	-12.5	-29.8	-14.5	-21.6	-16.4	-18.9

(a) The AER has converted 2009–10 real dollars to 2010–11 real dollars.

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

APT Allgas proposed that based on its roll forward model, the adjustment to the capital base for inflation be estimated by applying the year-on-year change in the CPI for the June quarter.[5]

3.3.1.3 Depreciation in the earlier access arrangement period

APT Allgas proposed to roll forward its capital base to 1 July 2011 using the forecast depreciation amounts approved by the QCA for the earlier access arrangement period.[6] APT Allgas made no adjustment to the depreciation amounts for the difference between actual and forecast inflation. Table 3.4 presents APT Allgas's proposed depreciation amounts for the earlier access arrangement period.

5 APT Allgas, Email to AER, *Confidential information and material outstanding*, 7 October 2010.
6 APT Allgas, *Access arrangement submission*, September 2010, p. 57.

Table 3.4: APT Allgas's depreciation for the earlier access arrangement period ($m, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11
Straight-line depreciation	8.1	9.5	10.4	11.4	11.9

Source: APT Allgas, *Access arrangement information*, September 2010, p.6.

3.3.2 Projected capital base

APT Allgas has proposed a projected closing capital base of $560.0 million ($ nominal) for the access arrangement period. The calculation of the projected capital base is shown in Table 3.5.

Table 3.5: APT Allgas's projected capital base ($m, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Opening capital base	421.7	446.5	472.3	500.7	529.9
plus forecast capex [a]	26.8	26.8	29.3	30.1	31.3
less forecast depreciation	1.9	1.0	0.9	0.9	1.3
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	446.5	472.3	500.7	529.9	560.0

Source: APT Allgas, *Access arrangement information*, October 2010, p. 11.
a: As at 30 June 2012.

3.3.2.1 Forecast capital expenditure for the access arrangement period

APT Allgas has proposed forecast capex of $128.6 million ($2010–11) for the access arrangement period. The proposed forecast capex is set out in Table 3.6.

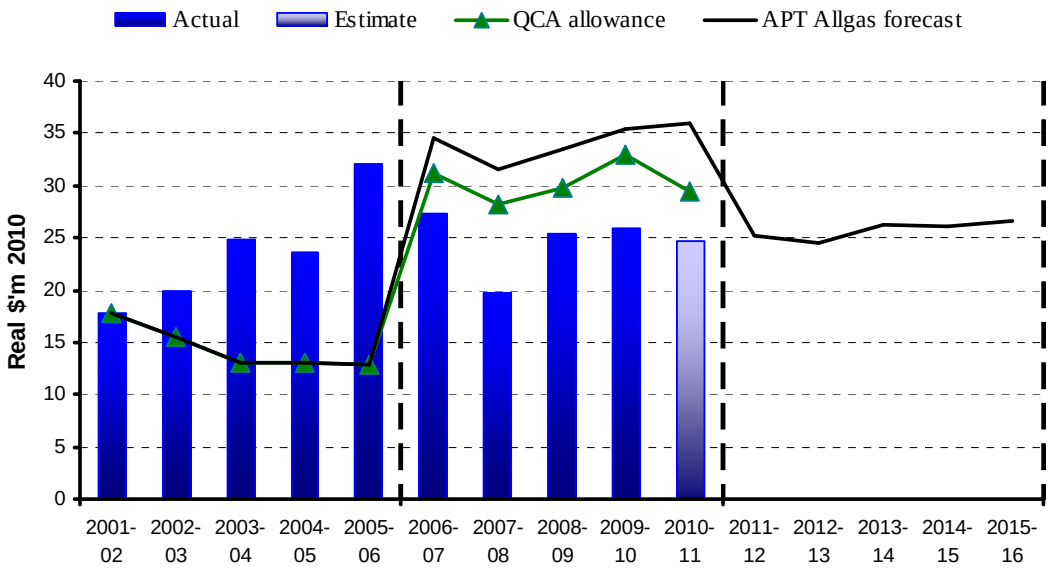
Table 3.6: APT Allgas's proposed forecast capital expenditure for the access arrangement period ($m, real 2010–11) [a]

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
System capex	22.0	22.6	24.8	25.6	26.1	121.1
Customer requested	14.8	15.5	15.9	16.6	17.3	80.2
Network augmentation	1.6	1.5	3.0	2.3	2.5	10.8
Network renewal	5.7	5.6	5.9	6.6	6.3	30.1
Sub total	22 .0	22.6	24.8	25.5	26.1	121.1
Non-system capex	3.1	2.0	1.4	0.6	0.5	7.5
Total capex	**25 .1**	**24.6**	**26.2**	**26.2**	**26.6**	**128.6**

Source: APT Allgas, *Access arrangement information*, October 2010, p. 8.
a: The AER has converted nominal dollars to 2010–11 real dollars.

Figure 3.2 below shows the APT Allgas capex from the earlier access arrangement period and the proposed capex for the access arrangement period. There is a 5.1 per cent increase in capex in the access arrangement period.

Figure 3.2: APT Allgas capital expenditure



Source: APT Allgas, *Access arrangement submission*, September 2010, pp. 39,46.
APT Allgas, *Access arrangement information*, February 2006, p. 21.
QCA, *Revised access arrangement for gas distribution networks: Allgas Energy - final decision*, May 2006, p. 47.
QCA, *Proposed access arrangements for gas distribution networks: Allgas Energy Limited and APT Allgas Limited - draft decision*, March 2001, p. 147.

APT Allgas engaged independent consultant, Parsons Brinckerhoff (PB) to provide an independent assessment of its forecast capex for the access arrangement period.[7] PB stated that it considered that the projects in the proposed capex program were justified with regards to r. 79 and 74 of the NGR, and that the estimates of costs were reasonable.[8]

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

APT Allgas has proposed an actual percentage change in the consumer price index (CPI) for the purposes of rolling forward the regulatory asset base. APT Allgas has proposed a forecast annual inflation rate of 2.50 per cent.[9]

3.3.2.3 Forecast depreciation allowance in the access arrangement period

APT Allgas's proposed allowance for depreciation in the earlier access arrangement period is discussed in chapter 4.

3.4 Consultant review

The AER engaged Wilson Cook & Co Limited, engineering and management consultants, to review APT Allgas's proposed capex (the Wilson Cook report).[10] This includes a review of the capex for the earlier access arrangement period, as well as APT Allgas's forecast capex for the access arrangement period.

For the earlier access arrangement period, Wilson Cook concluded that $116.2 million ($2010–11) of capex incurred, or projected to be incurred, may be accepted as being prudent and efficient.[11] Wilson Cook noted the following:[12]

- APT Allgas's plans and their accompanying documents to be suitable, in a general sense, for the prudent management of its assets
- APT Allgas's response to the global financial crisis (GFC) was sound commercially and that its approach to optimising its capex to maximise connections whilst minimising connection cost was sound.
- APT Allgas's approach to reduce expenditure on mains replacement commensurately with the relatively low level of UAG of between 3 to 4 per cent of gas input was sound
- the benchmarking of capex is not valid. This is because it considers that the networks of the businesses compared usually vary considerably along with the nature of and timing of the capex requirements in relation to them.[13]

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7 APT Allgas, *Access arrangement submission*, October 2010, p. 47 and APT Allgas, *Access arrangement submission*, October 2010, appendix 4-5.
8 APT Allgas, *Access arrangement submission*, October 2010, appendix 4-5, p. 20.
9 APT Allgas's PTRM in an email to the AER, *RE: Confidential information and material outstanding*, 7 October 2010.
10 Wilson Cook, *Review of expenditure of Queensland & South Australian gas distributors: APT Allgas Energy Pty Ltd (Queensland)* December 2010.
11 Wilson Cook, *Report – APT Allgas*, December 2010, pp. 12-13.
12 Wilson Cook, *Report – APT Allgas*, December 2010, pp. 9-10.

For the access arrangement period, Wilson Cook concluded that APT Allgas's proposed forecast capex may be accepted as being prudent and efficient.[14] In particular it considered:

- the forecast expenditure on network renewal is prudent and efficient
- the planned growth related expenditure is prudent in scope and timing
- the proposed augmentation expenditure is prudent in scope but should be adjusted to remove the contingency allowance.[15]

3.5 Submissions

No submissions were received from interested parties regarding APT Allgas's opening and projected capital base.

3.6 AER's consideration

The AER has undertaken an assessment of the capital expenditure in the earlier access arrangement period that APT Allgas has proposed to add to the opening capital base.[16] Whilst the AER is satisfied with the majority of the components of APT Allgas's opening capital base, the AER requires APT Allgas to account for amendments to the depreciation amounts used by APT Allgas to roll forward its capital base to 1 July 2011. The AER has also undertaken an assessment of APT Allgas's proposed capex for the access arrangement period.[17] The AER assessed APT Allgas's projected network renewal capex, customer requested capex and other capex activities. The AER's assessment of APT Allgas's proposed capex included a consideration of other cost factors that impact on APT Allgas's projected capital base including contingency allowances, overheads and cost escalators. Other elements that will affect APT Allgas's revenue in the access arrangement period such as capital contributions, disposals and depreciation were also reviewed by the AER.

3.6.1 Opening capital base

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

- first, the value of the capital base at 1 July 2006 is obtained from the previous access arrangement determination and a true-up is made for any difference between actual and estimated capex in 2005–06. Other adjustments may be necessary as circumstances require;
- second, the opening capital base at 1 July 2006 is rolled forward to 30 June 2011. This involves:
    - adding conforming capex over the earlier access arrangement period;

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13 APT Allgas, *Access arrangement information,* September 2010, attachment 5-8 (confidential).
14 Wilson Cook, *Report – APT Allgas*, December 2010, p. 16.
15 Wilson Cook, *Report – APT Allgas*, December 2010, p. 19.
16 NGR, r. 77.
17 NGR, rr. 72 and 79.

- removing regulatory depreciation;
- removing any redundant capital and disposals; and,
- indexing the capital base and other components of the roll forward for actual inflation.

The following sections provide details on the issues that emerge during these steps.

While the AER is satisfied with the majority of APT Allgas's opening capital base, the AER requires APT Allgas to amend the depreciation amounts and inflation used to roll forward its capital base to 1 July 2011. APT Allgas has used inflation rates that are inconsistent with the approach used for the calculating inflation in the tariff control mechanism approved for the earlier access arrangement. As a result, the AER does not consider that APT Allgas's proposed opening capital base is consistent with r. 77 of the NGR. as it does not comply with the relevant requirements of the NGR and as such is not consistent with the national gas objective of the NGL. The AER requires APT Allgas to make the amendments set out in section 3.8 of this draft decision.

3.6.1.1 Opening capital base for the earlier access arrangement period

The AER accepts that APT Allgas updated the opening capital base as at 1 July 2006 correctly. In particular APT Allgas has updated the capital base for the difference between actual and forecast capex and disposals for 2005-06. Together these adjustments explain the bulk of the change from the opening capital base forecast by the QCA. Other adjustments (related to issues with APT Allgas's use of regulatory account data) only have minor net impact on the opening capital base and the AER considers these adjustments reasonable in the circumstances. The adjustments to the opening capital base as at 1 July 2006 are summarised in the table 3.7.

Table 3.7: AER approved opening capital based as at 1 July 2006 ($m, nominal)

	As at 1 July 2006
QCA final approval (p.3)	303.1
APT Allgas's adjustment for actual capex	1.9
APT Allgas's adjustment for actual disposals	-2.6
Other adjustments	0.3
AER approved opening capital base	302.7

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 is conforming. 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. The AER considers that the capex incurred by APT Allgas over

the earlier access arrangement period was compliant. Therefore, a total of $122.9 million ($2010–11) has been added to the opening capital base at 1 July 2006.

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

- One of APT Allgas's responses to the Global Financial Crisis (GFC) was to maximise new connections whilst minimising customer connection cost.[18] Wilson Cook considered that APT Allgas's customer-requested capex incurred over the previous access arrangement, influenced by this strategy, was prudent and efficient. APT Allgas spent $73.5m ($2010–11) in customer requested capex, which was 11.1% less than the QCA forecast of $82.7m over the course of the previous access arrangement period. Although APT Allgas underspent in this category, customer requested expenditure still accounted for the largest category in APT Allgas's overall capex makeup, as illustrated in figure 3.3.

- Despite the higher average unit rate of $285 per metre ($2009–10) for mains replacement (from the QCA's forecast of $146 per metre ($2009–10)), this work is contracted out through competitive practices. Wilson Cook noted that the work may not have been carried out in the same areas as was forecast for the earlier access arrangement period.[19] The AER has accepted APT Allgas's network renewal capex as prudent and efficient. In real terms, APT Allgas spent an amount equal to that forecast by the QCA for this category over the five years of the earlier access arrangement period.

- The work that APT Allgas carried out for network augmentation was contracted out competitively, and the explanations of the projects undertaken were reasonable.[20] As such, the AER and its consultant Wilson Cook considered that the network augmentation capex was prudent and efficient.[21] APT Allgas underspent its network augmentation allowance by a considerable amount ($6.5m, real 2010–11), mainly due to the prudent deferral of a large augmentation project for supply to the South Coast.[22]

- APT Allgas underspent non-system capex, mostly due to the deferral of some IT improvements. The non-system capex projects in the earlier access arrangement period were justifiable, and the expenditure was prudent and efficient.[23]

- The capex provided by APT Allgas for the year 2010–11 is an estimate. This will be updated in APT Allgas's revised access arrangement proposal.

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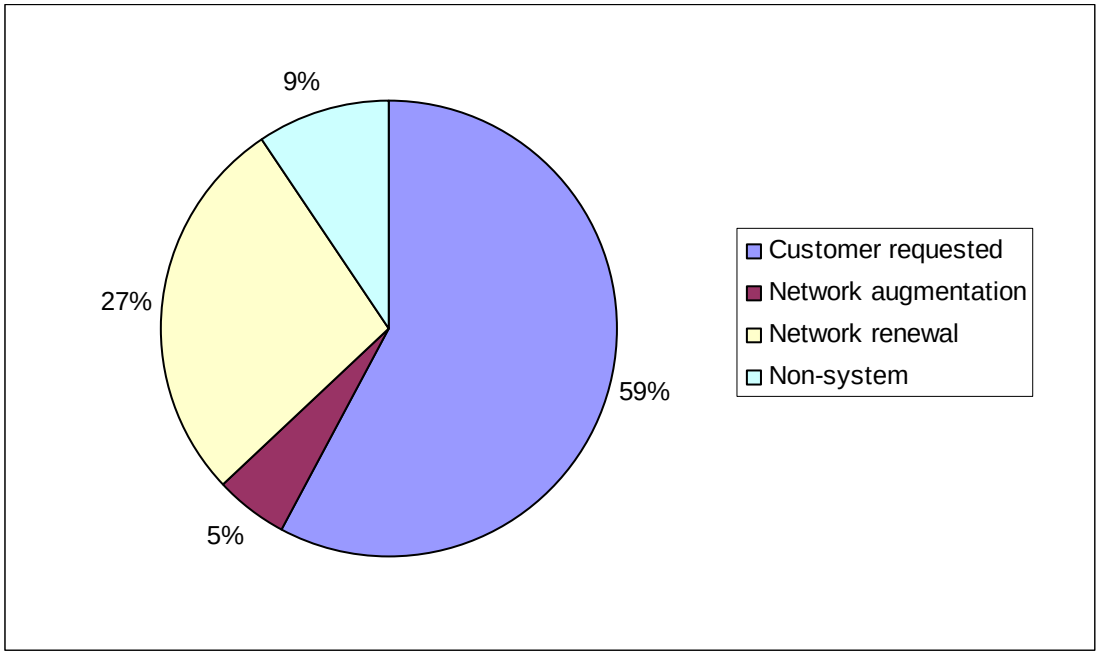
18 Wilson Cook, *Report – APT Allgas*, December 2010, p. 9.
19 Wilson Cook, *Report – APT Allgas*, December 2010, p. 10.
20 APT Allgas, *Access arrangement submission*, September 2010, attachment 4-4.
21 Wilson Cook, *Report – APT Allgas*, December 2010, p. 10.
22 APT Allgas, *Access arrangement submission*, September 2010, p. 40.
23 Wilson Cook, *Report – APT Allgas*, December 2010, p.10.

Figure 3.3: Capital expenditure by category over the earlier access arrangement period



3.6.1.3 Depreciation used in the roll forward model

The AER agrees with APT Allgas that forecast depreciation as approved by the QCA at the last reset should be used as the basis for rolling forward the capital base to 1 July 2011. However, the AER considers that these forecast amounts should be adjusted for actual inflation, which APT Allgas has not done. The AER has amended APT Allgas's roll forward model, adjusting the depreciation amounts for actual inflation. The revised straight-line depreciation amounts are shown in table 3.8. Compared to the depreciation amounts proposed by APT Allgas, the impact on APT Allgas's opening capital base of the AER's approved depreciation is a reduction of $0.3 million ($ nominal).

Table 3.8: AER approved depreciation for the earlier access arrangement period ($m, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11
Straight-line depreciation	8.2	9.5	10.4	11.4	12.0
APT Allgas proposed depreciation	8.1	9.5	10.4	11.4	11.9

Source: APT Allgas, *Access arrangement information*, September 2010, p. 6.

3.6.1.4 Adjustment to the capital base for inflation

The AER considers that the inflation rates (2005-06 to 2010-11) used for calculating the roll forward of the capital base should be adjusted from those proposed by APT Allgas. The AER has adjusted the inflation rates used for calculating the roll forward of the capital base from June to June figures to March to March figures to be consistent with CPI figures used for the form of control over the earlier access

arrangement period. These revised CPI figures increase the capital base from that originally proposed by APT Allgas.

3.6.1.5 Capital redundancy policy in the earlier access arrangement period

APT Allgas's capital redundancy mechanism in the earlier access arrangement period was established under the Gas Code. APT Allgas did not consider that any of its assets became redundant during the earlier access arrangement period and that no assets that were previously classified as redundant were re-used during the earlier access arrangement period.[24]

The AER has reviewed APT Allgas's proposal and accepts that no adjustments for redundant assets have been made by APT Allgas to its opening capital base.

3.6.1.6 Summary on the opening capital base

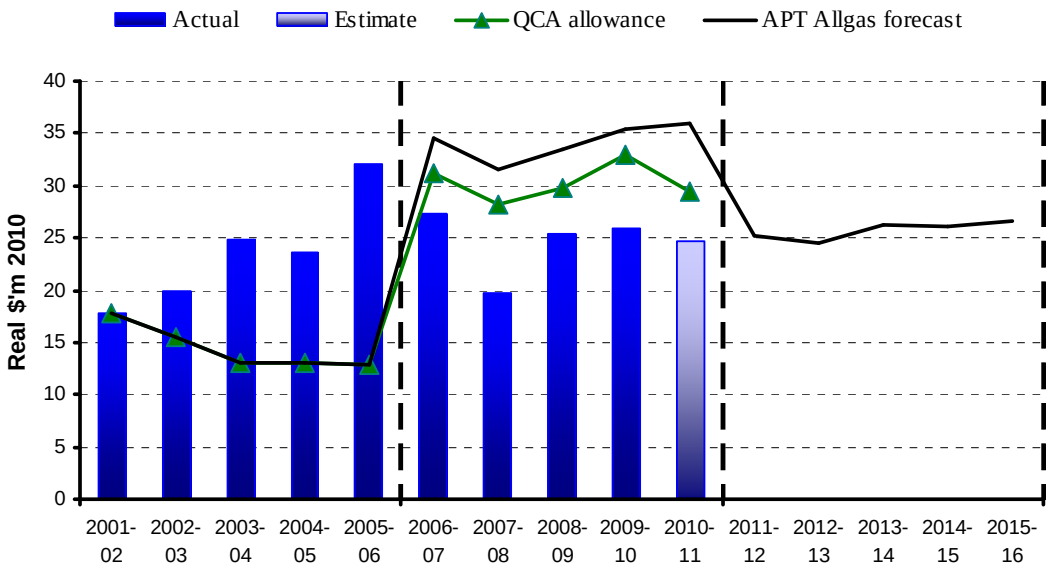
The AER has considered the components of APT Allgas's proposed opening capital base. The AER requires an amendment to the opening capital base to account for amendments in depreciation and inflation for the earlier access arrangement period. As a result, the AER does not consider that APT Allgas's proposed opening capital base is consistent with r.77(2) of the NGR. APT Allgas is required to amend its access arrangement information as outlined section 3.8 of this draft decision.

3.6.2 Projected capital base

APT Allgas has proposed that its capex over the access arrangement period should be higher than that incurred during the earlier access arrangement period. In total, APT Allgas has proposed a 5.1% increase in capex. If this proposed increase in capex is undertaken, tariffs will increase. Compared to APT Allgas's proposed capex, the capex estimated by the AER would increase the proposed tariffs by about 0.1 per cent per annum. If capex were to be maintained at the same level as over the earlier access arrangement period, the proposed tariffs would be only 0.2 per cent per annum higher than those estimated by the AER (or 0.1 per cent per annum higher than those proposed by APT Allgas). Figure 3.4 below shows the APT Allgas capex from the earlier access arrangement period and the proposed capex for the access arrangement period.

[24] APT Allgas, *Access arrangement submission*, September 2010, p. 45.

Figure 3.4: APT Allgas capital expenditure



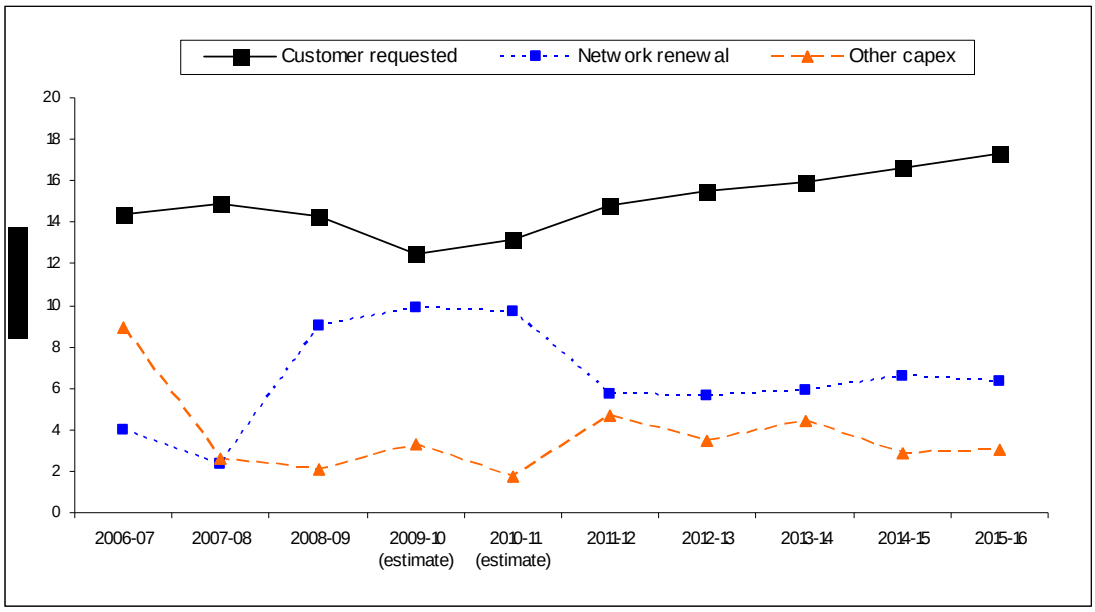
Source: APT Allgas, *Access arrangement submission*, September 2010, pp. 39,46.
APT Allgas, *Access arrangement information*, February 2006, p. 21.
QCA, *Revised access arrangement for gas distribution networks: Allgas Energy - final decision*, May 2006, p. 47.
QCA, *Proposed access arrangements for gas distribution networks: Allgas Energy Limited and APT Allgas Limited - draft decision*, March 2001, p. 147.

The AER has examined APT Allgas's proposed capex program. The AER considers that it is important that APT Allgas's capex proposal is consistent with the requirements of the NGR and represents value for money for customers. The AER has come to the conclusion that most elements of APT Allgas's capex program are justified. While there are some aspects of the program that are not adequately justified, the AER considers that, overall, the value of these were not sufficiently large to reject APT Allgas's capex proposal of $128.6 million ($2010–11).

The AER undertook an assessment of the components that APT Allgas has proposed to add to the projected capital base for the access arrangement period.[25] The largest component of the capex program relates to customer requested capital expenditure. Customer requested capex is required to meet the capacity needs of new customers, and includes assets such as mains, meters, and services.[26] Figure 3.5 illustrates the makeup of APT Allgas's capex over the earlier access arrangement period and the access arrangement period, and how the expenditure in these categories has changed (and is forecast to change) over time. The AER's consideration of the elements of APT Allgas's capex program is discussed below.

[25] NGR, r.78.
[26] APT Allgas, *Access arrangement submission*, September 2010, p. 48.

Figure 3.5: APT Allgas's forecast capital expenditure by purpose – 2006–07 to 2015–16



3.6.2.1 Customer requested capital expenditure

APT Allgas's proposed $80.2 million of customer requested capex is 15.7 per cent higher than the $69.3 million ($2010–11) incurred in the earlier access arrangement period.[27] The AER observes that the customer requested capex program comprises expenditure on mains, meters and services, and that the forecast customer requested capex is directly related to forecasts of new customer connections.[28] APT Allgas has forecast an increase in overall customer connections during the access arrangement period, and this is a major driver in the increase in customer requested capex.[29] This is the largest item of capex forecast for the access arrangement period.

As discussed in chapter 9, in considering advice from ACIL Tasman, the AER does not consider APT Allgas's forecast decline in average gas consumption for volume business class customers and the forecast of new connections in the small business sector to be appropriate.[30]

There has been a downward trend in small business customer connections over the earlier access arrangement period. Despite this, APT Allgas has forecast a gradual increase in small business customer connections over the access arrangement period. As discussed in chapter 9, the AER does not consider this forecast to be reasonable. As the customer requested capex program is linked to the forecasts of customers, the AER expects APT Allgas to reduce its customer requested capex program to reflect the lower forecasts for small business customer connections.

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27 APT Allgas, *Access arrangement submission*, September 2010, p. 46.
28 APT Allgas, *Access arrangement submission*, September 2010, p. 48 and attachment 4.2, September 2010.
29 APT Allgas, *Access arrangement submission*, September 2010, attachment 4.5.
30 ACIL Tasman, p. 20.

The AER also reviewed the cost estimates of the proposed customer requested capex program. Informed by advice from Wilson Cook, the AER has considered the following:

- the composition of the forecast unit rates, including the breakdown of rates in the additional data received are within the range expected.[31]

- the length of mains extensions work related to new connections proposed is within the expected range.[32] The lengths of mains extensions required has been based on historical data. For industrial and commercial customers with annual consumption below 10 TJ, a length of 20 meters has been allowed and, in the case of customers with greater demand, 100 meters has been allowed.[33]

- the proposed unit rates for cost of meters, regulators and meter boxes are within the range expected.[34]

The AER considers that overall, the proposed customer requested capital is prudent in scope and timing.[35] The AER considers that the proposed customer requested expenditure results in a net benefit to customers.

On the basis of the information provided by APT Allgas and the advice of Wilson Cook, the AER is satisfied the estimated costs proposed by APT Allgas are reasonable. Consequently, the AER considers that the proposed customer requested capex is justified, however, APT Allgas's revised proposal should take into account a revised forecast of small business customer connections as discussed in chapter 9.

3.6.2.2 Network augmentation capital expenditure

APT Allgas has proposed $10.8 million ($2010–11) for network augmentation capex over the access arrangement period.[36] This expenditure is necessary to maintain capacity to meet current customer demands which includes safety and integrity of supply.[37] The AER is largely satisfied that this expenditure is justified, subject to the considerations below.

The AER considered the costs and justification for the five network augmentation projects to be completed in the access arrangement period. [38] One of the projects that APT Allgas described is due to be completed during the earlier access arrangement period and does not impact on forecast capex. Based on the submitted business cases for each project, the AER considers that there are security of supply and network

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31 Wilson Cook, *Report – APT Allgas*, p. 16.
32 Wilson Cook, *Report – APT Allgas*, p. 16.
33 Wilson Cook, *Report – APT Allgas*, p. 16.
34 Wilson Cook, *Report – APT Allgas*, p. 16.
35 Wilson Cook, *Report – APT Allgas*, p. 16.
36 APT Allgas, *Access arrangement submission*, September 2010, p. 46.
37 APT Allgas, *Access arrangement submission*, September 2010, p. 48.
38 The augmentation capex projects that APT Allgas proposes includes, Upgrade Tingalpa gate station ($497 222 (real 2010-11)), Augmentation of supply Surfers Paradise and Broadbeach ($2.41 million ($2010-11), South Coast supply project stage 2 ($7.32 million (($2010-11)), Pressure upgrade for Cleveland pipeline ($165 551 real 2010-11 dollars), Broadbeach high pressure polyethylene network augmentation ($124 000 ($2010-11)), and Minor network augmentation projects (approximately $50 000 per year ($2010-11)).

integrity considerations that support the need for this expenditure.[39] The AER also considers that the timing of expenditure for the augmentation projects is prudent on the basis of current demand forecasts. The AER has concluded that each project is justified under the NGR. Wilson Cook also considered that each project is justified under the NGR.[40]

The cost estimates for the network augmentation expenditure are based on historical costs for similar projects.[41]

The AER considers that the inclusion of non-specific contingency allowances into expenditure plans is unsuitable for regulatory purposes (see section 3.6.2.5).

On this basis, the AER considers that APT Allgas has made the case for its network augmentation programs, and that these programs are justified. With the exceptions referred to in sections 3.6.2.5 and 3.6.2.6, the AER considers that the proposed network renewal capex forecasts are justified.

3.6.2.3 Network renewal capital expenditure

APT Allgas's proposed $30.1 million ($2010–11) on network renewal capex is $4.8 million ($2010–11) less than incurred in the earlier access arrangement period.[42] APT Allgas submitted that network renewal capex comprises mains replacement, meter replacement and expenditure in relation to other system assets.[43]

APT Allgas has proposed 90 km[44] of mains to be replaced over the access arrangement period, or 18 km per annum. APT Allgas has also submitted that the majority of the expenditure in network renewal is on mains replacement. Table 3.9 sets out APT Allgas's mains replacement forecast.

Table 3.9: Mains replacement forecast (km)

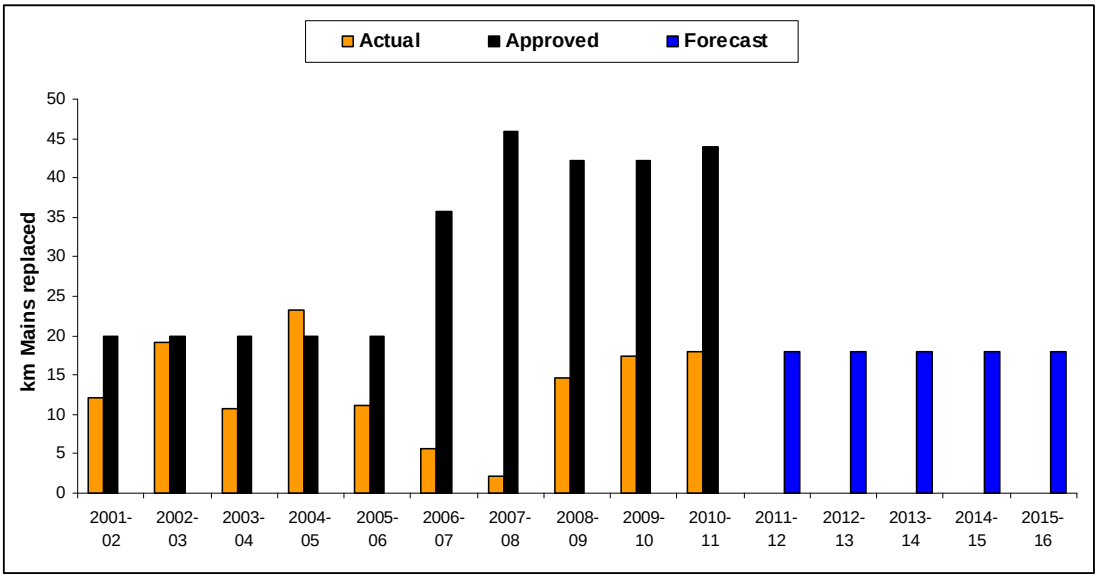
	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Total mains replacement	18	18	18	18	18	90

Source: APT Allgas, *Access arrangement submission*, September 2010, attachment 4.3.

The annual rate of mains replacement for the access arrangement period is similar to the final three years of the earlier access arrangement period.[45] Figure 3.6 illustrates the actual, QCA approved and forecast mains replacement rate.

39 APT Allgas, *Access arrangement submission*, September 2010, attachments 4.2 and 4.8.
40 Wilson Cook, *Report – APT Allgas*, p. 19.
41 APT Allgas, *Access arrangement submission*, September 2010, pg 48.
42 APT Allgas, *Access arrangement submission*, September 2010, pp. 39, 46.
43 APT Allgas, *Access arrangement submission*, September 2010, p. 50.
44 APT Allgas, *Access arrangement submission*, September 2010, attachment 4.3.
45 APT Allgas, *Access arrangement submission*, September 2010, attachment 4.3.

Figure 3.6: Mains replacement–APT Allgas



Source: APT Allgas, *Access arrangement submission*, September 2010, attachment 4.3.
ECG, A*llgas Energy Pty Ltd capital and operating expenditure review*, April 2006, p. 66.

The AER considers that a modest level of mains replacement has been proposed by APT Allgas for the access arrangement period, as was also considered by Wilson Cook.[46] The objective of APT Allgas's mains replacement program is to minimise expenditure on this item while slowly reducing current maintenance and UAG costs.[47] In the longer term, APT Allgas proposes to replace 435 km of low and medium pressure mains over the next 25 years, and submits that a rate of replacement of 18 km per year is appropriate to achieve this.[48] Wilson Cook noted that the mains replacement program will address capacity limitations at the same time while reducing the level of risk in high-risk areas. Wilson Cook considered that the proposed rate of mains replacement is well supported and prudent.[49]

The AER further considers that there are real safety and security of supply concerns related to the aging nature of certain parts of APT Allgas's network.[50] Leaking gas in certain areas will contribute to a risk of fire or explosion. The AER recognises that modern gas appliances require higher pressures and that older networks may have difficulty in delivering such pressures. In these circumstances, the AER considers that a prudent and efficient mains replacement program is justified under the NGR.

The implied cost per metre of mains replacement over the access arrangement period was calculated by Wilson Cook to be $244 per metre, as compared to the implied rate over the earlier access arrangement period of $292 per metre ($2010–11).[51] This appears to be a reduction in cost, however, factors such as the location of the mains replaced and whether replacement work is conducted piecemeal or by block will

46 Wilson Cook, *Report – APT Allgas*, p. 17.
47 Wilson Cook, *Report – APT Allgas*, p. 17.
48 APT Allgas, *Access arrangement submission*, September 2010, p. 51.
49 Wilson Cook, *Report – APT Allgas*, p. 17.
50 APT Allgas, *Access arrangement submission*, September 2010, attachment 4.3.
51 Wilson Cook, *Report – APT Allgas*, p. 18.

influence this figure. The AER considers that as the work is contracted out competitively, the cost estimates are reasonable. The AER agrees with Wilson Cook that the forecast cost of mains replacement is prudent and efficient.[52]

On this basis, the AER considers that APT Allgas has made the case for it network renewal programs, and that these programs are justified. With the exceptions laid out in sections 3.6.2.5 and 3.6.2.6, the AER considers that the proposed network renewal capex forecasts are justified.

3.6.2.4 Non-system capital expenditure

APT Allgas has proposed $7.6 million ($2010–11) of non-system expenditure forecast over the access arrangement period.[53]

IT Systems

APT Allgas has proposed four IT projects upgrading of IT applications ($0.4 million), upgrading and renewal of IT infrastructure ($0.4 million), 'road map' initiatives ($3.6 million) and knowledge management ($0.6 million).[54]

The AER considers that IT expenditure is a necessity for a business of this type, and that APT Allgas's proposed expenditure is based in projects and software upgrades that contribute to the delivery of pipeline services. Absent appropriate IT systems, it is likely that customers would experience security of supply and safety issues. As such, it is appropriate for APT Allgas to implement capex programs to upgrade and reinforce its IT systems.

The AER considers that the process of estimating the non-system capex costs undertaken by APT Allgas is prudent and efficient, and the projects nominated are reasonable. However, as also noted by Wilson Cook[55], the AER does not consider the inclusion of contingency allowances in the proposed expenditure to be reasonable. Contingencies are discussed in more detail in section 3.6.2.5.

On the basis of its analysis, and informed by advice from Wilson Cook, the AER does not consider APT Allgas's proposed expenditure on IT systems to be justified, due to the inclusion of contingency allowances.

Other non-systems capital expenditure

The remaining items in other non-system capex amounts to $2.6 million ($2010–11). This expenditure contains such items as SCADA systems and miscellaneous tools, equipment and other non-reticulation items.[56] The AER considers that such items are necessary for the operation of a gas distribution network service provider.

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52 Wilson Cook, *Report – APT Allgas*, p. 18.
53 APT Allgas, *Access arrangement submission*, September 2010, p. 51. Non-systems capex includes costs associated with IT systems and software, motor vehicles and plant and equipment that are not part of the distribution network.
54 APT Allgas, *Access arrangement submission*, September 2010, attachment 4-8.
55 Wilson Cook, *Report – APT Allgas*, p. 20.
56 APT Allgas, *Access arrangement submission*, September 2010, p 54.

In some cases, where the proposed expenditure on an item is relatively small, the AER has undertaken a high level review of the proposed costs to establish consistency with the previous pattern of capex established by APT Allgas.

In its analysis of APT Allgas's proposal, the AER observed that APT Allgas's proposed expenditure on non-system capex over the access arrangement period is lower in real dollar terms than its actual expenditure in this category over the earlier access arrangement period. The AER considers that APT Allgas's other non-system capex is prudent and efficient with the exceptions detailed in sections 3.2.6.5 and 3.6.2.6. This view was consistent with Wilson Cook's advice to the AER.[57]

3.6.2.5 Other adjustments to the proposed capital base

Overheads

Overhead costs include, for example, costs associated with network planning, procurement, fleet and other costs that are not related to specific capex categories and are allocated across other capex categories. The AER considers that overhead costs need to be directly referable to the delivery of pipeline services.[58] APT Allgas has proposed an overhead rate of, on average, 26.2 per cent per annum that is applied to all forecast capex.[59]

In reviewing the proposed overhead costs, the AER considered:

1. How the components of overheads costs relate to the provision of pipeline services

2. Whether any of the overheads cost would be recovered elsewhere – that is, the potential for double counting

3. Whether the overhead costs proposed by APT Allgas are reasonable

APT Allgas provided little detailed information on overheads in its access arrangement proposal. On request from the AER, APT Allgas provided information detailing the costs that make up the capital overheads. APT Allgas submitted that its forecast overheads are based on the regulatory accounting principles and processes used by Energex.[60] It further submits that its capitalised overheads comprise the following costs:

- Support Departments, which includes the following sub categories:
  - Finance and Administration;
  - Human Resources;
  - Operations Admin and Management;
  - Business Support;

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57 Wilson Cook, *Report – APT Allgas*, p. 20.
58 NGL, s.2 and 23.
59 APT Allgas, Email to AER, *Re. AER APT.16*, 19 November 2010, attachment.
60 APT Allgas, Email to AER, *Re. AER APT.16*, 19 November 2010, attachment.

- Regional Operations at Toowoomba and Mansfield.

- Support Functions, which includes the following sub-categories:
  - Property;
  - Motor Vehicles;
  - Insurance;
  - Communication;
  - Legal and other external services.
- Overheads, including the following sub-categories:
  - Local overheads
  - Corporate overheads.[61]

The AER accepts APT Allgas's composition of the capital overheads and notes that the cost categories described are those that would be incurred for the delivery of pipeline services.[62]

The AER also requested information from APT Allgas on whether the costs are allocated to the APA Group or to APT Allgas.[63] In response APT Allgas has submitted that its overheads are not allocated to a third party.[64] The AER accepts that APT Allgas's capitalised overhead allocation is appropriate.

Wilson Cook noted that it is normal practice for overheads associated with putting new fixed assets into service to be recognised as a cost component and added to the regulatory asset base.[65] Wilson Cook considered that given the increase in the capex program, the level of overheads should be appropriately assessed.[66] Wilson Cook stated that:

> It is an accounting matter to confirm whether the proposed level of capitalisation of overheads is reasonable. If an investigation finds it not to be so, the application rate should be reduced accordingly.[67]

The AER agrees with the advice from Wilson Cook. Although the capitalised overheads are associated with expenditure incurred for delivering pipeline services, the AER considers that APT Allgas's proposed forecast levels of overheads are inappropriate.

The AER considers the overall capex incurred during 2009–10 was efficient because it was below the approved QCA expenditure levels. Because the AER considers APT Allgas's allocation of capitalised overheads is appropriate, it considers that the

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61 APT Allgas, Email to the AER, *Re. AER APT Allgas.16*, 16 December 2010.
62 NGL, s. 2 and s. 23.
63 AER, Email to APT Allgas, *AER APT.16&17*, 17 November 2010.
64 APT Allgas email to AER, *Re. AER APT.16*, 19 November 2010.
65 Wilson Cook, *Report – APT Allgas*, p. 21.
66 Wilson Cook, *Report – APT Allgas*, p. 21.
67 Wilson Cook, *Report – APT Allgas*, p. 21.

overheads incurred in 2009–10 of $5.2 million[68] ($2010–11) were also efficient. Therefore the AER considers that these overheads are at efficient levels and should provide the basis for forecasting expenditure in the access arrangement period.

The AER agrees in principle that the allocation of overheads applied to the forecast capex proposed by APT Allgas complies with s. 2 and s. 23 of the NGL, but considers that the rate of overheads as proposed by APT Allgas is not consistent with the NGR.[69] The AER considers that $5.2 million of overheads each year is an appropriate level of overhead costs for APT Allgas. This results in a total overhead cost of $26.1 million over the access arrangement period, compared to the $26.7 million ($2010–11) proposed by APT Allgas, a reduction of 2.2 per cent.

Contingencies

The AER recognises that the process for estimating capex, although expected to be efficient and final, is not necessarily an exact process. The AER therefore considers that a contingency allowance for a cost estimation risk factor of the type proposed by APT Allgas may be appropriate in some circumstances. Typically, such circumstances apply where the allowance is informed by specific instances of actual past cost increases where the inherent risks and some contingent risk could be identified in the determination of the base estimate. The Australian Competition Tribunal's (Tribunal) formed such an opinion in respect of its decision on an application by East Australian Pipeline Limited (EAPL). In that decision, the Tribunal allowed a contingency factor in the calculation of an optimised replacement cost (ORC) to cover construction cost omissions as the Tribunal considered a prudent potential new entrant would allow for contingencies and include them in its calculation of its ORC to arrive at its "buy or build" depreciated optimised replacement cost.[70]

The AER considers that in its application to the Tribunal, EAPL provided significant design and cost estimate details on its pipeline network based on experience and knowledge of the network upon which its contingency for omissions was based. Further, the Tribunal considered the replacement cost of a complete pipeline which the AER considers is likely to have significantly greater cost uncertainties and risks than the capital projects proposed by APT Allgas (IT systems).

APT Allgas's proposed contingencies did not include details on the justification of a contingency. APT Allgas has substantial experience in the construction, installation and estimation of capex activities, including such projects involving IT systems, and should be able to identity and estimate all the relevant costs for these activities. It is the view of the AER that APT Allgas's capex estimates should contain minimal cost omissions.

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68 APT Allgas, Email to the AER, *Re. AER APT Allgas Overheads*, 16 December 2010.
69 NGR, r. 72(1)(c)(i) and r. 74(2)(b).
70 Australian Competition Tribunal, *East Australian Pipeline Limited [2004] ACompT 8*, paragraph 50, 8 July 2004.

In its review of APT Allgas's capex Wilson Cook considered that it was not appropriate for non-specific contingency allowances to be added to expenditure estimates in regulatory submissions for the following reasons:[71]

- The allowances constitute a provision

- Whilst a contingency allowance may need to be called on in some instances, such allowances are unlikely to be called on generally, or to their full extent; and to argue that they would is to say, in essence, that the business concerned is unable to estimate its costs accurately or that it does not wish any risk of cost overruns to remain.[72]

The AER agrees with Wilson Cook that the forecasting and budgeting processes proposed by APT Allgas are sound, refined periodically and capable of producing estimates that prove, in the event, to have been accurate.[73] Wilson Cook considered that there is no reason why any general contingency or other such general allowance ought to be agreed to for capex, as it has not been established that it is necessary.[74]

Further, the AER considers that in some cases contingency allowances may be symmetrical resulting in deductions from the forecast expenditure. Without a detailed analysis and review of each specific expenditure item, such symmetries cannot be identified. The AER considers that a general contingency allowance, which is purely based on estimates, will not show this.

The AER therefore considers that APT Allgas's proposed capex on non-system capex is excessive and not consistent with r. 79(2)(c) of the NGR.

3.6.2.6 Cost escalators

The AER's consideration of APT Allgas's proposed cost escalators is discussed in chapter 7. For the reasons outlined in chapter 7, the AER is not satisfied that the proposed cost escalators applied to APT Allgas's forecast capex comply with the requirements of r. 79 and r. 74(2) of the NGR.

3.6.2.7 Conclusion on capital expenditure

The AER does not consider that the APT Allgas forecast capex complies with the requirements of 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, to achieve the lowest sustainable cost of providing services.

Further, the AER considers that the APT Allgas 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

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71 Wilson Cook, *Report – APT Allgas*, pp. 20-21.
72 Wilson Cook, *Report – APT Allgas*, pp. 20-21.
73 Wilson Cook, *Report – APT Allgas*, pp. 20-21.
74 Wilson Cook, *Report – APT Allgas*, p. 36.

natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.[75]

Table 3.10 shows the capex proposed by APT Allgas compared with the capex which the AER considers satisfy the capex criteria of the NGR.[76]

Table 3.10: APT Allgas's proposed and estimated capital expenditure for 2011–2016 ($m, 2010–11)

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Network renewal						
APT Allgas proposed	5.66	5.61	5.94	6.63	6.30	30.13
AER forecast	5.67	5.56	5.82	6.38	5.93	29.36
Customer requested						
APT Allgas proposed	14.78	15.49	15.91	16.63	17.35	80.16
AER forecast	14.80	15.37	15.59	15.99	16.35	78.10
Other capex						
APT Allgas proposed	4.70	3.45	4.33	2.91	2.92	18.31
AER forecast	4.38	3.22	4.13	2.79	2.75	17.27
Total capex						
APT Allgas proposed	25.14	24.55	26.18	26.17	26.56	128.6
AER forecast	24.85	24.15	25.55	25.16	25.03	124.73

The AER considers that the difference between the AER's estimate of forecast capex and that proposed by APT Allgas of $3.9 million ($2010–11) is not large enough to require APT Allgas to amend its capex proposal. This is because while the AER does not agree with the forecast costs of some elements of the capex program, overall the forecast costs proposed by APT Allgas are not materially different to those estimated by the AER. The AER accepts that the process for estimating capex is not an exact process and that there is some degree of imprecision in estimating capex. Also, the AER provides a business with a sufficient pool of funds to provide services to meet its current and future customer's requirements. It does not direct a business how it should allocate its approved capex allowance during the access arrangement period. For these reasons, the AER does not require APT Allgas to amend its proposed forecast capex, not withstanding the exceptions to APT Allgas' proposal that the AER has identified.

[75] NGL, s. 23.
[76] NGR, r. 79.

3.6.2.8 Capital contributions

The AER notes that APT Allgas has not proposed any non-conforming capital contributions for the access arrangement period.[77] However APT Allgas has proposed that where capex does not comply with the requirements set out under r. 79(2)(b) of the NGR, capital contributions will be sought from the new users concerned.[78] The AER notes that APT Allgas will be required to provide one-off payments made by users.

APT Allgas has submitted that because it treats capital contributions as revenue in the year in which they are received, then this revenue is removed from the total revenue requirement.[79]The AER notes that this ensures that APT Allgas receives no net benefit in the form of return on or of capital from the addition of the capital contribution to the capital base. The AER considers that this is consistent with r. 82(3) of the NGR. Therefore the AER is not proposing that APT Allgas amend its access arrangement proposal for capital contributions.

3.6.2.9 Depreciation

The AER's assessment of APT Allgas's forecast depreciation allowance is presented in chapter 4. Table 3.11 reproduces the conclusions from that chapter.

Table 3.11: AER approved depreciation for the access arrangement period ($'000, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Straight-line depreciation	8931	12,894	13,447	14,808	15,833
Inflationary gain	10,681	11,398	12,035	12,737	13,442
Regulatory depreciation	-1750	1496	1412	2071	2391

The AER requires APT Allgas to amend its forecast depreciation as outlined in chapter 4 of this draft decision.

3.6.2.10 Forecast disposals

APT Allgas has submitted that it does not propose any disposals for the access arrangement period.[80]

The AER accepts the APT Allgas proposal that no value for disposals is forecast of material value in the projected capital base for the access arrangement period.[81] In

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77 APT Allgas, *Access arrangement submission*, September 2010, p. 55.

78 APT Allgas, *Access arrangement submission*, September 2010, pp. 44-45 and APT Allgas, *Access arrangement submission*, September 2010, attachment 4.5.

79 APT Allgas, *Access arrangement submission*, September 2010, pp. 44-45 and APT Allgas, *Access arrangement*, September, 2010, pp. 8-9.

80 APT Allgas, *Access arrangement information*, September 2010, p. 10.

doing so the AER notes that the opening capital base for next access arrangement period commencing 1 July 2016 will be net of the value of any assets disposed of during the access arrangement period.

3.6.2.11 Adjustment to the capital base for inflation

The AER's consideration of the APT Allgas 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 2.52 per cent over a 10 year period for the access arrangement period.

3.6.2.12 Summary for projected capital base

The AER has considered the components of the APT Allgas proposed projected capital base. The AER has determined that APT Allgas's forecast depreciation and adjustment of the capital base for inflation does not comply with r.74(2) and r.78 of the NGR. However, as noted above, the AER considers that the difference between the AER's estimate of forecast capex and that proposed by APT Allgas ($3.9 million ($2010–11)) is not large enough to require APT Allgas to amend its capex proposal.

3.6.3 Closing capital base for the access arrangement period

With regard to r. 90 of the NGR, APT Allgas proposed to continue to roll forward the capital base using forecast depreciation, rather than actual depreciation, at the next reset.[82]

The AER considers APT Allgas's proposal to use forecast depreciation in establishing the opening capital base for the access arrangement period commencing 1 July 2016 is consistent with r. 90 of the NGR. Forecast depreciation updates the depreciation determined in this decision only for actual inflation. No adjustment is made to the forecast depreciation for any difference between forecast and actual capex over the access arrangement period. This approach is also consistent with the approach outlined in the AER's access arrangement guideline.[83]

3.6.4 Other access arrangement proposal provisions relevant to the capital base

3.6.4.1 Capital redundancy policy

APT Allgas proposes to retain its capital redundancy policy included in the earlier access arrangement period in addition to an additional provision for costs associated with a decline in the volume of sales of services provided by means of its covered network to be shared between APT Allgas and users.[84] For the earlier access

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81 APT Allgas, *Access arrangement information*, September 2010, p. 10.
82 APT Allgas, *Access arrangement submission*, September 2010, p. 60.
83 AER, *Access arrangement guideline*, March 2009, pp. 61–62.
84 APT Allgas, *Access arrangement submission*, September, 2010, p. 56.

arrangement period, APT Allgas proposed that the QCA may reduce APT Allgas's capital base by an amount for: [85]

- any assets that have ceased to contribute to the delivery of services
- any assets that have been sold or disposed of by the service provider or the service provider has entered into a binding agreement for their sale or disposal.

The AER considers that it is appropriate to retain consistency with the capital redundancy policy that applied during the earlier access arrangement period and therefore accepts the capital redundancy policy proposed by APT Allgas.

3.7 Conclusion

Opening capital base

The AER does not propose to approve the opening capital base proposed by APT Allgas for the access arrangement period as it does not comply with r.77(2) of the NGR and requires APT Allgas to make amendments as set out in section 3.8 of this draft decision.

Forecast capital expenditure

The AER proposes to approve the projected capital base proposed by APT Allgas.

Closing capital base for the access arrangement period

The AER proposes to approve APT Allgas's proposed depreciation on the basis of forecast depreciation (based on forecast capital expenditure) for establishing the opening capital base 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.

The AER proposes to approve the capital redundancy mechanism proposed by APT Allgas to remove redundant assets from the capital base proposed as it complies with r. 77(2)(e) of the NGR and r. 85(1) of the NGR.

3.8 Required amendments

Before the proposed access arrangement can be accepted, APT Allgas must make the following amendment:

Amendment 3.1: amend the access arrangement and access arrangement information in order to be consistent with the following table:

[85] QCA, *Draft decision, Revised access arrangement for gas distribution networks:Allgas Energy*, December 2005, p. 51.

Table 3.12: AER approved opening capital base ($m, nominal)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12
Opening capital base	302.7	327.1	350.7	374.0	399.4	423.8
Add gross capex	25.2	19.3	25.1	26.6	26.4	
Add indexation	7.4	13.9	8.7	10.8	10.1	
Less depreciation	8.2	9.5	10.4	11.4	12.0	
Less capital contributions						
Less redundant assets						
Less disposals			0.05	0.2		
Closing capital base	327.1	350.7	374.0	399.4	423.8	

4 Depreciation

Depreciation affects total revenue in two ways. First, it is a component of the projected capital base, and second, it is a separate depreciation building block.

The AER accepts APT Allgas's proposed standard asset lives for the access arrangement period. These lives are generally shorter than those used during the earlier access arrangement period.

APT Allgas made errors in its calculation of the forecast depreciation allowance. These errors also affected the remaining asset lives as at 1 July 2011. The AER requires amendments be made to these asset lives as a result.

The AER rejects APT Allgas's proposed forecast depreciation allowance. The AER determined a total of $65 million in straight-line depreciation for the access arrangement period. This total reflects the revised remaining asset lives and the various factors that affect the capital base over the access arrangement period.

4.1 Introduction

This chapter sets out the AER's consideration of APT Allgas's proposed depreciation schedule and asset lives for the access arrangement period against the requirements of the NGR. No submissions were received on APT Allgas's proposed depreciation schedules.

4.2 Regulatory requirements

APT Allgas is required to provide a depreciation schedule that sets out the basis upon 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.

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.[1]

4.3 Access arrangement proposal

APT Allgas proposed estimating depreciation in the access arrangement period using a straight line method of depreciation. Table 4.1 sets out APT Allgas's forecast depreciation for the access arrangement period.

Table 4.1: APT Allgas's proposed depreciation for the access arrangement period ($'000, nominal)

	2010–11	2012–13	2013–14	2014–15	2015–16
Regulatory depreciation [a]	1911	986	911	854	1263

Source: APT Allgas, *Access arrangement information*, September 2010, p. 9.
(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 remaining asset lives and standard (economic) asset lives presented in table 4.2. This table only presents the significant depreciable asset categories in APT Allgas's PTRM. It also does not present any legacy asset categories. For example, APT Allgas continues to treat 'Capex 2000-01 system' as a separate asset category in its modelling. APT Allgas has revised the standard asset lives from those used by the QCA in the earlier access arrangement period.

[1] This clause is also relevant if the AER makes its own proposal for revision of a transitional access arrangement under r. 63 or r. 64 of the NGR.

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

Asset Class	Remaining life	Standard Life
Network Pressure Control Facilities	27.5	40.0
HP Steel Mains	60.0	80.0
Distribution Mains	34.0	50.0
Distribution Mains - Steel Unprotected	17.6	50.0
Distribution Mains - PVC	28.2	50.0
Distribution Mains - Copper	34.7	50.0
M/LP Customer Services PE	35.1	50.0
M/LP Customer Services ST	35.2	50.0
Contract Metering Equipment	4.4	15.0
Tariff Metering Equipment	3.6	15.0
SCADA & Telemetry	4.7	15.0
Equipment & Others	3.3	10.0

Source: APT Allgas's RFM in an email to the AER, *RE: Confidential information and material outstanding*, 7 October 2010.

APT Allgas stated that the standard asset lives used by the QCA are the longest of any gas network in Australia.[2] APT Allgas stated that these economic lives did not allow it to fund steady state network renewal.[3] Rather than conducting its own technical engineering assessment of the standard lives of different assets, APT Allgas based its proposal on the standard lives for system assets as approved by the AER in its final decision on ActewAGL's access arrangement for 2010-15.[4] The exception to this is district regulators (network pressure control facilities) for which APT Allgas proposed a standard asset life of 40 years. Table 4.3 provides a summary of APT Allgas's assessment of its key asset categories against the AER's decision for ActewAGL and its proposed standard asset lives for the access arrangement period.

2 APT Allgas, *Access arrangement submission*, September 2010, p. 58.
3 APT Allgas, *Access arrangement submission*, September 2010, p. 58.
4 APT Allgas, *Access arrangement submission*, September 2010, p. 59.

Table 4.3: APT Allgas's assessment of standard asset lives (years)

Asset Class	Previous AA	ActewAGL approved	APT Allgas proposed
HP steel mains	105	80	80
HP Services	105	50	50
Distribution mains and services	PVC – 30 PE – 80 Steel – 45 Copper – 85 Cast iron - 80	50	50
District regulators	50	15	40
Contract meters	30	15	15
Tariff meters	25	15	15

Source: APT Allgas, *Access arrangement submission*, September 2010, p. 59.

4.4 AER's consideration

In assessing the depreciation schedules proposed by APT Allgas, the AER reviewed the proposed:

- depreciation approach
- asset lives, used to determine the depreciation rate
- forecast depreciation allowance.

4.4.1 Depreciation approach

The AER considers that APT Allgas's use of the straight-line depreciation method is consistent with r. 89(1)(a) of the NGR in allowing for reference tariffs to vary over time in a way that promotes efficient growth in the market for reference services. Over the life of an asset, straight-line depreciation leads to relatively smooth price changes, which is appropriate as consumption of haulage services is expected to grow steadily over the access arrangement period.

4.4.2 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:

1. the standard asset lives to be applied to new assets, and
2. the remaining asset lives of existing assets.

4.4.2.1 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 (r. 89(1)(a) of the NGR). In the case of the ActewAGL decision, the AER accepted the standard asset lives proposed by ActewAGL on the basis that these were the same asset lives as approved by the ICRC for the previous access arrangement period.[5] In the Jemena decision, the AER also accepted the standard asset lives because they were consistent with the asset lives used for the previous access arrangement period.[6]

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. The AER accepts the standard asset lives used by the QCA were relatively long compared to other gas networks in Australia. The standard asset lives used for ActewAGL are considered to be consistent with r. 89(1)(b) of the NGR that requires assets to be depreciated over their economic life. The standard asset life proposed for district regulators is consistent with standard asset lives approved by the AER for Country Energy (Wagga Wagga) and the business case presented by Envestra in Queensland for those assets.[7] The non-system standard asset lives are generally consistent with standard lives used in the earlier access arrangement period. Therefore, the AER accepts the standard asset lives as proposed by APT Allgas for the access arrangement period.

4.4.2.2 Remaining asset lives

Clause 5(1)(d) of schedule 1 of the NGR requires the AER to take into account the depreciation schedules from the earlier access arrangement. Consistency in the remaining asset lives proposed by a service provider with the asset lives used for previous access arrangement periods has been usual practice in other AER decisions.[8]

The AER reviewed APT Allgas's calculation of remaining asset lives as at 1 July 2011, comparing them against its calculation of the assets' weighted average remaining asset life using the asset lives applied by the QCA in the earlier access arrangement period. The AER found significant differences between its calculations and those of APT Allgas and invited APT Allgas to comment on these differences.[9] For example, the AER estimated a remaining asset life of 42.9 years for network pressure control facilities, compared to the 27.5 years proposed by APT Allgas.

In its response, APT Allgas stated there were errors in its models.[10] These errors were in the calculation of the forecast depreciation allowance which used remaining asset lives as determined at 1 July 2006, rather than 1 July 2011. Correcting for these errors

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5 AER, *Draft Decision: ActewAGL Access arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network,1 July 2010 – 30 June 2015*, November 2009, p. 54. The standard asset lives did not change for the final decision.

6 AER, *Draft Decision: Jemena, Access arrangement proposal for the NSW gas Networks, 1 July 2010 – 30 June 2015*, February 2010, p. 84.

7 Envestra, *Qld access arrangement information*, October 2010, p. 116.

8 See for example, AER, *Draft decision: Country Energy Wagga Wagga, Natural Gas Distribution Network Access arrangement proposal, 1 July 2010 – 30 June 2015*, November 2009, p. 39.

9 AER, Email to APT Allgas, *AER.APT.15: 2011 remaining life calculations*, 12 November 2010.

10 APT Allgas, Email to the AER, *AER Depreciation*, 2 December 2010.

would (other things being equal) significantly increased APT Allgas's forecast depreciation allowance, if the remaining asset lives as originally proposed were to be used.

In its proposal, APT Allgas had adjusted its remaining asset lives because it considered it was not receiving sufficient cash flow from depreciation (r. 89(1)(e) of the NGR). In response to the AER's inquiry and the subsequent error that was identified, APT Allgas recalculated the remaining asset lives using a weighted average approach based on the asset lives used by the QCA. It then applied an adjustment factor to some of the asset categories to arrive at revised remaining asset lives, which would deliver (other things being equal) the same projected depreciation allowance as its original proposal. These revised remaining asset lives along with the weighted average remaining asset lives and those lives contained in its proposal are shown in table 4.4.

Table 4.4: APT Allgas's revised remaining asset lives as at 30 June 2011 (years)

Asset Category	Proposed remaining life	Weighted ave. remaining life	Revised remaining life
Network Pressure Control Facilities	27.5	42.9	35.8
HP Steel Mains	60.0	87.9	73.4
Distribution Mains	34.0	70.5	58.9
Distribution Mains - Steel Unprotected	17.6	11.1	9.3
Distribution Mains – PVC	28.2	13.0	13.0
Distribution Mains – Copper	34.7	73.0	73.0
M/LP Customer Services PE	35.1	49.4	41.3
M/LP Customer Services ST	35.2	107.7	107.7
Contract Metering Equipment	4.4	22.8	19.0
Tariff Metering Equipment	3.6	19.9	16.6
SCADA & Telemetry	4.7	68.1	68.1
Equipment & Others	3.3	5.0	5.0

Source: APT Allgas's RFM in an email to the AER, *RE: Confidential information and material outstanding*, 7 October 2010, and APT Allgas, Email to the AER, *AER Depreciation*, 2 December 2010.

The AER does not agree that the standard asset lives used by the QCA were necessarily contrary to APT Allgas's reasonable cash flow needs (r. 89(1)(e) of the NGR). APT Allgas presented no analysis in this regard and merely asserted its position.[11] Excluding the impact of inflation on the capital base (that is, the negative

[11] APT Allgas, *Access arrangement submission*, September 2010, p. 58.

depreciation effect of inflation), the QCA's model shows that the forecast depreciation allowance APT Allgas received over the earlier access arrangement period was more than one and half times larger than the capex it was forecast to spend on network renewals.[12]

Despite these observations, the AER is mindful that r. 89(1)(c) of the NGR allows for adjustment to the depreciation schedule so as to reflect changes to asset lives. The AER has accepted APT Allgas's proposed changes to standard asset lives for new assets. Accordingly, the AER considers that some revision to the remaining asset lives is also warranted.

The AER does not accept the remaining asset lives as originally proposed by APT Allgas. Rule 89(1)(a) of the NGR provides that the depreciation schedule should be designed so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services. In this regard, the AER considers that the step up in prices (about 3.2 per cent per annum) that would result if APT Allgas's proposed remaining lives were adopted would risk efficient growth of the market for reference services. APT Allgas's approach to calculating the revised remaining asset lives appears to implicitly recognise such a concern by scaling back only the weighted average remaining asset lives by an amount sufficient to generate the same depreciation allowance as originally proposed.

If the revised remaining asset lives calculated by APT Allgas are used to determine forecast depreciation, prices will be about 0.5 per cent per annum higher than what they would have been had the weighted average remaining asset lives been used. The AER considers that the size of this impact does not risk efficient growth of the market for reference services. Therefore, the AER considers that the revised remaining asset lives in table 4.5 should be used to calculate APT Allgas's forecast depreciation allowance. These remaining asset lives achieve a balance in the considerations under r. 89(1) of the NGR and clause 5(1)(d) of schedule 1 of the NGR.

4.4.3 Forecast depreciation

Due to the changes in asset lives noted above and changes to the capital base noted in chapter 3 of this draft decision, the AER has recalculated the forecast depreciation for the access arrangement period. This revised forecast is shown in table 4.6.

[12] QCA, *Allgas – Final model – adjusted for redundant assets.xls*

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	8931	12 894	13 447	14 808	15 833
Inflationary gain	10 681	11 398	12 035	12 737	13 442
Regulatory depreciation	-1750	1496	1412	2071	2391

Regulatory depreciation is straight-line depreciation net of the inflationary increase in the capital base for each year. As discussed in chapter 5, the forecast inflation has been set at 2.52 per cent per annum for each year of the access arrangement period for the draft decision. This inflation forecast will be updated for the final decision.

APT Allgas'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.

4.5 Conclusion

The AER has accepted the depreciation approach and the standard asset lives proposed by APT Allgas. However, due to errors in APT Allgas's calculation of forecast depreciation, the remaining asset lives were recalculated. In addition, due to changes in the capital base noted in chapter 3 of the draft decision, the forecast depreciation allowance for the access arrangement period has been revised. The AER therefore does not approve the depreciation schedule proposed by APT Allgas for the access arrangement period as it does not comply with r. 89(1) of the NGR.

4.6 Required amendments

Before its access arrangement proposal can be accepted, APT Allgas must make the following amendment:

Amendment 4.1: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of revised remaining asset lives in table 4.4 of this draft decision.

Amendment 4.2: 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 APT Allgas's proposed rate of return of 10.30 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 9.96 per cent is appropriate for the benchmark service provider. The AER considers that APT Allgas'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 APT Allgas are reflective of the risks involved in providing reference services under prevailing market conditions. Similarly, the AER has also rejected APT Allgas'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, and more than sufficient to cover APT Allgas's actual cost of debt.

The AER has calculated a rate of return of 9.96 per cent. This reflects market based parameters (risk free rate and debt margin) estimated over an indicative averaging period of 7 December 2010 to 6 January 2011 and will be updated for the final decision.

5.1 Introduction

This chapter sets out the AER's estimate of an efficient benchmark rate of return on capital for APT Allgas 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 arrived at on a reasonable basis, be supported by a statement of the basis of that forecast or estimate, 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

APT Allgas proposed a nominal vanilla WACC approach to determine the rate of return on its projected capital base.[1] APT Allgas proposed the use of the (standard) Sharpe-Lintner CAPM to determine the cost of equity.[2]

Consistent with past state regulator practice, APT Allgas included debt raising costs in the cost of debt used to calculate the nominal vanilla WACC. However, 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.[3] Table 5.1 presents APT Allgas's proposed WACC with and without debt raising costs.

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1 The AER notes that APT Allgas labels its WACC approach a 'post tax nominal vanilla WACC' and a 'post tax nominal WACC' in its access arrangement submission. The label 'nominal vanilla WACC' is used by APT Allgas in its access arrangement information, and the formula set out in this document is the nominal vanilla WACC formula. APT Allgas, *Access Arrangement Submission, Effective 01 July 2011–30 June 2016*, 1 October 2010, pp. 76–77, APT Allgas, *Access Arrangement Information, Effective 01 July 2011–30 June 2016*, 1 October 2010, pp. 17–18.

2 APT Allgas, *Access Arrangement Information, Effective 01 July 2011–30 June 2016*, 1 October 2010, p. 17.

3 The AER includes a specific allowance in operating expenditure for debt raising costs. See appendix F of this decision.

Table 5.1: WACC parameters proposed by APT Allgas

WACC Parameter	APT Allgas proposal
Nominal risk–free rate (%)	5.07
Inflation (%)	2.50
Real risk–free rate[a] (%)	2.51
Equity beta	1.1
Market risk premium (%)	6.5
Debt risk premium (%)	3.85
Debt raising costs[b] (%)	0.108
Gearing (%)	60
Cost of equity (%)	12.22
Cost of debt including debt raising costs (%)	9.03
Cost of debt (%)	8.92
Nominal vanilla WACC including debt raising costs (%)	10.30
Nominal vanilla WACC (%)	**10.24**

Source: APT Allgas, *Access Arrangement Submission, Effective 01 July 2011–30 June 2016*, 1 October 2010, pp. 75, 76; APT Allgas, *Access Arrangement Information, Effective 01 July 2011–30 June 2016*, 1 October 2010, p. 18 (table 7.1); AER analysis.

(a) The real risk–free rate has been derived from the APT Allgas proposal using the Fisher equation.

(b) Debt raising costs are reported as a WACC component in the APT Allgas proposal. The AER separately considers an operating allowance for debt raising costs in appendix F of this decision.

(c) Gamma does not directly enter the nominal vanilla WACC equation—since in this framework all adjustments for taxation are made in cash flows—but is listed here because it is linked to the other WACC parameters. The AER considers the value of gamma in chapter 6 of this decision.

In support of its proposal, APT Allgas submitted a report by Synergies Economic Consulting (Synergies).[4] In summary, APT Allgas's and Synergies' approaches with respect to individual parameters were as follows:

- Inflation forecast — based on the RBA's latest forecasts, combined with the midpoint of its target band out to a 10 year forecast horizon.

[4] Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network*, September 2010.

- Averaging period and risk free rate — no period was proposed, however an indicative risk free rate was calculated using the annualised yield on 10 year Commonwealth Government bonds over a period of 20 business days ending 27 August 2010.

- Gearing ratio — a ratio of 60 per cent was proposed, consistent with the last QCA and recent AER determinations, with Synergies raising concerns this may not be compatible with the BBB+ credit rating benchmark.

- Debt risk premium (DRP) — an average of CBASpectrum and Bloomberg fair value estimates was proposed to calculate a premium with respect to a 10 year, BBB+ credit rating benchmark.

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

- Equity beta — a value of 1.1 is consistent with the QCA's determination for the earlier access arrangement period, and also the view that APT Allgas's Queensland operating environment exposes it to higher systematic risk than other gas and electricity network service providers.

To support its claims with respect to the overall rate of return and equity beta in particular, Synergies Economic Consulting (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 that Officer and Bishop have estimated a forward looking estimate of 7–8 per cent. Based on this, Synergies stated that a 6.5 per cent MRP is currently likely to be a lower bound.[5] APT Allgas submitted that Officer and Bishop estimate a MRP of 7–8 per cent between 2011 and 2015.[6] Officer and Bishop estimated the historical long term average MRP to be 7 per cent, however, they considered that current market volatility (as at July 2010) is higher than volatility levels prior to the GFC. Officer and Bishop submitted that if the MRP is assumed to revert to a long run average over time, 8 per cent is the best estimate of the forward looking MRP over a five year time horizon.[7]

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5 Synergies, *Estimating WACC for the APT Allgas Distribution Network*, September 2010, pp. 40–41.

6 APT Allgas, *Access arrangement submission*, September 2010, p. 67. APT Allgas has not provided the Officer and Bishop paper 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.

7 Officer and Bishop, *Market risk premium, Comments on the AER draft distribution determination for Victorian electricity distribution network service providers*, July 2010.

5.4 AER's consideration

The AER has not accepted APT Allgas's proposed rate of return. In doing so, and in determined a rate of return it considers best meets the requirements of the NGR, the AER recognises that there is no single precise answer that can be determined through the mechanistic application of a mathematical formula or parameter estimates developed in isolation. In determining an appropriate rate of return the AER has been required to review 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 of 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 law and rules, and most likely in excess of the value needed to meet these requirements.

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
- 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 C.

5.4.1 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 section 24(2)(a) of the NGL which requires the AER to provide a service provider 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 APT Allgas.

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 AER has also considered the analysis presented by APT Allgas regarding the relationship between the return on equity and debt, finding that this 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 C. This appendix also contains further analysis of the Modigliani and Miller theorem and its implications for the overall rate of return.

5.4.1.1 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.[8] Other recent sales have been at premiums of between 20 and 119 per cent to the regulated asset base and trading multiples of 15 to 73 per cent (see appendix C).

As supported by Grant Samuel, listed infrastructure entities should theoretically trade at, and be acquired at, 1.0 times the RAB.[9] 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 that amounts allowed by the regulator
- increase the service provider's revenues by encouraging demand for regulated services
- 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. The AER considers the premiums of this magnitude are unlikely to be explained by the factors notes 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 has been in excess of the actual cost of capital. The AER considers that 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

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8 AER, Final decision, *Wagga Wagga natural gas distribution network, 1 July 2010–30 June 2015,* March 2010 and ASX, *Envestra company announcement,* 26 October 2010, viewed 27 January 2011, < http://www.asx.net.au/asxpdf/20101026/pdf/31tcv1nblp4xqc.pdf>

9 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.

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.[10]

5.4.1.2 Relationship between return on equity and debt

APT Allgas presented analysis which it suggested demonstrated a predictable relationship between the cost of equity and the cost of debt, which was not being maintained by the AER in its recent decisions. It argued this implied the cost of equity set by the AER was too low, in particular that the cost of equity must be 4.5 per cent higher than the cost of debt.[11]

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. Further, the 4.5 per cent required difference between cost of equity and debt as proposed by APT Allgas 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

5.4.2 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.

The AER has accepted APT Allgas's proposal to use the CAPM as a well accepted model to estimate APT Allgas's 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. APT Allgas has proposed the use of the yield on 10 year Commonwealth Government Securities (CGS) as the proxy for the risk free rate.[12] The AER has accepted the use of

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10 See appendix C.1.2 of AER, *Draft Decision - Envestra Ltd Access arrangement proposal for the Qld gas network*, February 2011.

11 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 64 and Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network*, September 2010, p. 35.

12 APT Allgas, Access arrangement submission, September 2010, p. 65.

the yield on 10 year CGS.[13] To maintain consistency within the CAPM, the MRP must be estimated for a 10 year investment horizon.[14]

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[15] and in reports put forward by regulated entities.[16] 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.[17]

For the purposes of determining the best estimate of the MRP for APT Allgas, the AER has considered the national gas objective set out in the National Gas Law (NGL), 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. 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.[18] The value of the MRP is a highly contentious issue amongst academics and market practitioners and there is no definitive answer on what the value of the unobservable MRP should be. The AER has used its judgement to balance academic evidence and

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13 See section 5.4.6. The AER considered the term of the risk free rate in detail as part of the WACC review. The AER estimated the weighted average effective term to maturity for the debt portfolio of a benchmark efficient energy network business was 7.37 years. This was after hedging was taken into account. On this basis the AER considered the previous regulatory practice of using the yield on 10 year CGS as the proxy for the risk free rate was appropriate. See AER, *Final decision, Electricity transmission and distribution network service providers review of weighted average cost of capital (WACC) parameters*, 1 May 2009 (WACC review final decision), pp. 172–173.

14 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.

15 See for example 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.

16 See for example 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.

17 NGR, r. 87(1).

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

evidence from a range of other sources to achieve an outcome which balances the objectives set out in the NGL.

5.4.2.1 Previous regulatory practice

In regulatory decisions prior to the AER's WACC review final decision in 2009,[19] 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.[20]

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)[21]

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19 AER, *WACC review final decision*,1 May 2009 (WACC review final decision).

20 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.[22]

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.[23] 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.[24] 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.[25] Other studies suggesting a MRP greater than 6 per cent should be adopted have also been considered.[26]

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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21 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.

22 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.

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

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

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

26 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.[27]

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.

5.4.2.2 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.

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.

[27] AER, *WACC review final decision*, 1 May 2009, p. 238.

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

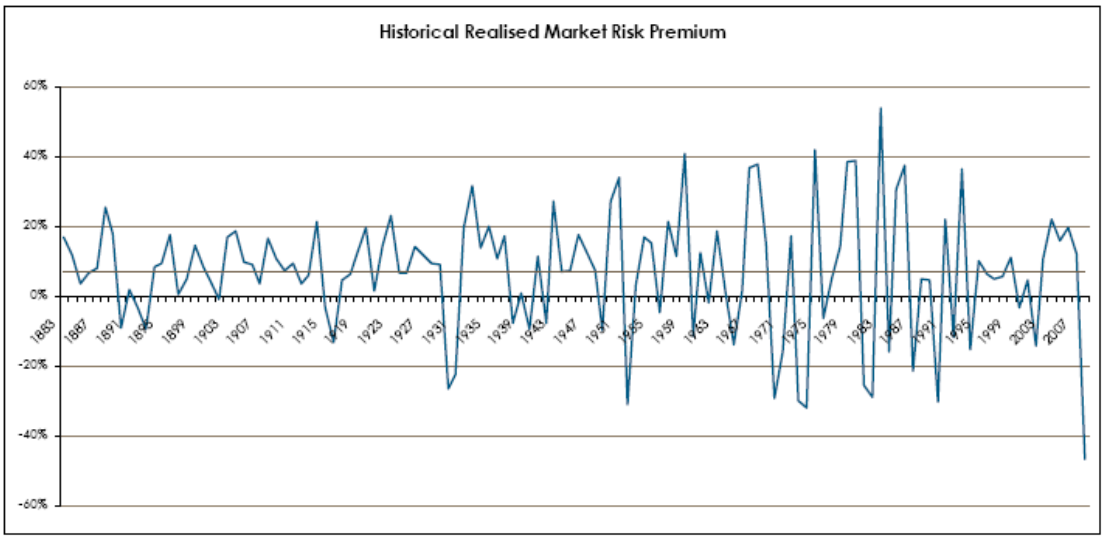
	2005	2007	2008	2009	2010
1883–	6.4%	6.6% (1.4%)	6.1% (1.5%)	6.4% (1.5%)	6.3% (1.5%)
1937–	6.1%	6.4% (2.3%)	5.7% (2.3%)	6.1% (2.3%)	6.1% (2.3%)
1958–	6.8%	7.2% (3.1%)	6.2% (3.2%)	6.7% (3.2%)	6.6% (3.1%)

Source: AER, *WACC review final decision*, 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 in these results 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.

While the historical estimates summarised in table 5.3 would suggest a forward looking MRP of 6.1–6.6 per cent for the period ending 2010. These values are 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 since:

- the estimates are subject to wide confidence intervals and as a result there is low statistical precision in the estimates[28]
- it could result in potentially significant changes to the MRP on the basis of what is 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.

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.[29] 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.

[28] 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. However, this in itself makes estimates of the actual MRP through time very difficult to estimate with accuracy.

[29] AER, *WACC review final decision*, 1 May 2010, pp. 198–199.

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.[30]

5.4.2.3 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.[31] 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.[32] 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.[33]

- within the Officer WACC framework, it is conceptually valid to take into account the value of distributed imputation credits when estimating historical excess returns by grossing up excess returns after 1987 for the assumed utilisation rate (theta) of imputation credits.[34]

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.[35] At the time of the WACC review final decision, the range for historical estimates was 5.7–6.2 per cent.[36] 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.[37]

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

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30 The difference between geometric and arithmetic means is discussed further in appendix C.
31 Officer and Bishop, *Market Risk Premium, Estimate for January 2010–June 2014, Prepared for WestNet Energy*, December 2009, pp. 9–10
32 Officer and Bishop, *Market risk premium, a review paper*, August 2008, p. 1.
33 AER, *WACC review final decision*, 1 May 2009, pp. 182–184.
34 AER, *WACC review final decision*, 1 May 2009, p. 209.
35 AER, *Explanatory statement, WACC review*, August 2008, p. 170.
36 AER, *WACC review final decision*, 1 May 2009, p. 209.
37 Officer and Bishop also use arithmetic means and therefore may also overstate the expected forward looking 10 year MRP. Officer and Bishop's estimate uses the same data as Associate Professor Handley for the period 1883–1958. Consequently Officer and Bishop's 7 per cent long term estimate of the MRP also suffers from the data issues outlined above.

for estimating gamma.[38] 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.[39] 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.

5.4.2.4 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.[40] 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. [41]

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 C.

5.4.2.5 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:

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38 In this regard, the AER notes the utilisation rate for imputation credits estimated by the AER is under consideration by the Australian Competition Tribunal. The Tribunal's decision in relation to the AER's estimate of the utilisation rate will affect the AER's best estimate of the utilisation rate in the future.

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

40 Synergies, *Estimating a WACC for the APT Allgas network*, September 2010, pp. 39–40.

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

- 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. [42]

During the WACC review the AER had regard to these surveys in concluding that 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.[43]

- 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.[44]

Independent valuation reports that were completed following the GFC have also adopted a MRP of 6 per cent.[45] 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.[46] 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.[47] Moreover, this evidence supports the view that

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

43 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.

44 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.

45 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.

46 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.

47 AER, Final decision, *Review of weighted average cost of capital parameters*, 1 May 2010, pp. 237–238.

6 per cent is the best estimate of the forward looking MRP in the current circumstances.

5.4.2.6 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).[48] 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.[49]
>
> 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.[50]

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

> 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.[51]

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.[52]

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48 Synergies, *Estimating a WACC for the APT Allgas network*, September 2010, pp. 38–39.

49 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.

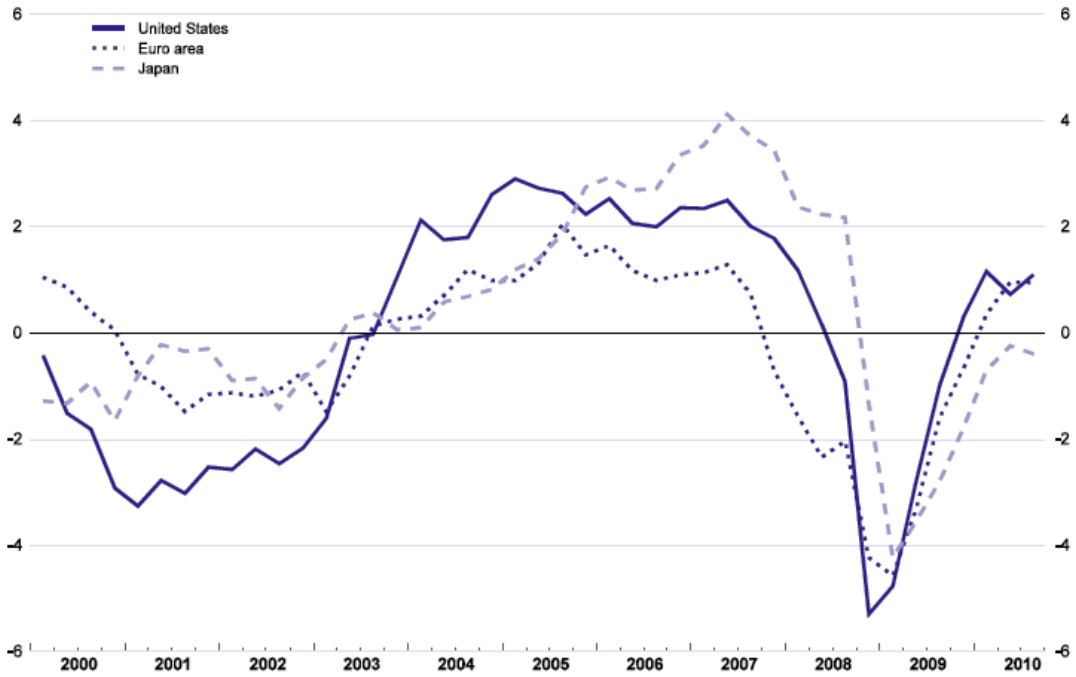
50 Yan Sun, *Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis*, IMF Working Paper, WP/10/27, May 2010, p. 19.

51 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.

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

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.[53] This indicates a positive global market outlook and is illustrated in figure 5.2.

Figure 5.2: OECD financial conditions index



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

5.4.2.7 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

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

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 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 APT Allgas 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 also 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.

5.4.3 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 firm's 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.[54] The cost of debt will also vary depending on the term of the debt. Higher yields are often associated with longer 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 10 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 10 and 8 year BBB estimates in late 2007 and August 2009 respectively, and then again in June 2010 stopped publishing 10 year AAA rated estimates. For the BBB fair values Bloomberg currently publishes, the AER has commented previously that these tend to reflect yield observations for bonds traded below a 7 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.[55]

In this context, and as further detailed in appendix C, the AER has not placed sole reliance on Bloomberg, and has instead averaged the extrapolated 10 year BBB Bloomberg fair values margin with the margin calculated from the APT bond.[56] The key considerations in reaching this decision are:

- there is some evidence to suggest that the behaviour of the Bloomberg curve since the onset of the GFC is somewhat counter intuitive, including the extrapolated 10 year DRP derived from Bloomberg currently being at an all time high

- the characteristics of the APT bond closely match those of the benchmark corporate bond set by the AER, namely BBB rated and approximately 10 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 resemble those of the benchmark gas pipeline service provider. To the extent that credit ratings are an imperfect indicator of default risk, the APT bond

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54 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.

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

56 The margin on the APT bond reflects a simple average of both Bloomberg and UBS yields over the 20-day averaging period ending 6 January 2011.

is suitable for deriving a DRP that reflects the risks involved in providing reference services

- a recently issued A- rated, 10 year bond by Stockland displays yields that are closer to the APT bond, and significantly below the extrapolated Bloomberg 10 year estimates. This gives further support for relying on the APT bond over Bloomberg

- a further 10 year BBB+ rated Dalrymple Bay Coal Terminal (DBCT) bond has yields that are higher than Bloomberg's BBB fair values, however the AER has discounted this observation for the purposes of comparison given previous issues with its owner and credit wrapper.

While the available evidence is limited, the AER considers that placing sole reliance on Bloomberg estimates would result in a rate of return that is excessive with respect to the risks involved in providing reference services. In particular, Bloomberg estimates imply that prevailing conditions in debt markets are more risky now than during the GFC. This is counterintuitive, and other evidence (such as that assessed in section 5.4.2) indicates financial market conditions have substantially improved since this time.

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 10 year, BBB fair value estimate and of the APT bond maturing in 2020. Based on the indicative averaging period for this draft decision, these two information sources produce margins over the risk free rate of 4.81 per cent and 3.06 per cent, which the AER has averaged to produce a DRP of 3.93 per cent.[57] The AER considers this is the best DRP estimate possible in the circumstances of APT Allgas.[58] The AER has also considered that the benchmark will provide APT Allgas a comfortable margin with respect to its expected actual cost of debt over the forthcoming access arrangement period.

Placing equal reliance on Bloomberg and the APT bond contrasts from the most recent decision of the AER (for the Victorian electricity distribution businesses) that 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, and recent issuance of the Stockland bond. The AER also notes that the Victorian 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.

5.4.4 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

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[57] As noted previously, the margin on the APT bond reflects a simple average of both Bloomberg and UBS yields over the 20-day averaging period ending 6 January 2011.

[58] Consistent with NGR, r. 74(2)(b).

'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 are 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
- 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.

In this context, the AER rejects APT Allgas's proposed equity beta estimate of 1.1 as it would result in a cost of capital which is excessive with respect to the risk involved in providing reference services. Appendix C contains further detail on particular issues raised by APT Allgas in relation to beta.

Using information provided by Competition Economist Group report for Envestra, the AER considers that a beta estimate in the range of 0.4 and 0.7 is still appropriate for this draft decision. Table 5.5 reproduces the most up to date beta estimates from the Competition Economist Group report. As is evident in table 5.5, the most recent beta estimate from Australian comparable firms (with the exception of Hasting[59]) is within the bound of 0.1 to 0.6.

[59] 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.

Table 5.5: Competition Economist Group beta analysis

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	n/a

Source: 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.[60] The AER considers that a reduction in APT Allgas's beta from 1.1 to within a range of 0.4 to 0.7 would be significant and potentially undermine investment certainty for regulated energy businesses. The AER 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 1.1 does not provide the best estimate of the equity beta given prevailing market conditions,[61] and requires APT Allgas to amend its access arrangement information as outlined in amendment 5.1.

5.4.5 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 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.

APT Allgas's method of calculating forecast inflation was to apply the RBA's short-term inflation forecasts extending out for two years and the mid-point of the RBA's target inflation band (that is, 2.5 per cent) for the remaining eight years. The forecast is the geometric average of the annual inflation for each of the ten years. This method

60 NGL, s. 24(2).
61 NGR, r. 74 (2)(b) and r. 87 (1).

is accepted by the AER as reasonable and is consistent with its recent regulatory determinations.[62]

APT Allgas's forecast of 2.53 per cent is slightly different from the 2.52 per cent calculated by the AER, as presented in table 5.6. The AER considers this difference is due to an inadvertent error. For the purpose of this draft decision, the AER has adopted an inflation forecast of 2.52% over a ten year period.

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%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.52%

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.

5.4.6 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 the risk of government default on interest and debt repayments is considered to be low.[63]

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.[64]

For the purposes of its access arrangement proposal, APT Allgas proposed to calculate the risk free rate as the annualised yields on 10 year CGS over an indicative averaging period of 20 business days ending 27 August 2010.[65] APT Allgas did not

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62 It should be noted that the AER has previously used a market-based inflation forecast derived by taking the difference between indexed and nominal Commonwealth Government Security (CGS) yields. The AER notes the resumption of issuance of Treasury Indexed Bonds by the Australian Office of Financial

63 AER, *WACC review final decision*, 1 May 2009, pp. 128–174.

64 AER, *WACC review final decision*, 1 May 2009, pp. 128–174.

65 APT Allgas, *Access arrangement submission, effective 01 July 2011–30 June 2016*, October 2010, p. 65.

propose a final averaging period which is a necessary component for the determination of the rate of return as required by r. 87 of the NGR.

When asked about this omission, APT Allgas responded that it intends to nominate an averaging period in response to the AER's draft decision.[66]

The AER considers that under r. 74 of the NGR, a proposed final averaging period must be submitted as part of the access arrangement proposal to support the estimates of WACC parameters (such as the risk free rate and debt risk premium), rather than providing an intention to submit an averaging period at a later date. Also as no final averaging period was proposed, the AER does not consider APT Allgas has demonstrated that its proposed approach to calculate the rate of return satisfies the requirements of r. 87 of the NGR.

The purpose of allowing the service provider to nominate the final averaging period is so that it can execute appropriate financing arrangements prior to or during the averaging period if it so chooses. This approach is justified under s. 24(2) of the NGL, as it ensures that the service provider has opportunity to recover at least its efficient costs. However, the AER considers that the final averaging period should not include a date in the past. This is to prevent gaming of the regulatory regime by deliberately selecting an averaging period with a higher risk free rate that would not be consistent with the requirement of r 87(1) of the NGR.

The AER requires that a final averaging period satisfying the following design criteria should be adopted for the access arrangement period:

1. The final averaging period should be nominated in advance of the commencement of the access arrangement period and should not include a date in the past.
2. The final averaging period should be between 10 and 40 business days in length.

The AER will accept a final averaging period that meets the averaging period design criteria and falls within the following boundaries:

- The final averaging period is nominated by APT Allgas no later than the lodgement of its revised regulatory proposal
- The final averaging period starts on a day that is after notification to the AER of the proposed period
- The final averaging period ends on or before Friday 29 April 2011
- The final averaging period is between 10 and 40 business days in length[67]

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66 APT Allgas, *Email re: APT Allgas – averaging period for risk free rate*, received 12 October 2010.

67 Note that an averaging period of 40 business days would use the entire available time, i.e. start on 3 March 2011 and conclude on 29 April 2011, as Anzac day (25 April 2011) falls on Easter Monday, and no additional public holiday is granted in Tasmania. Accordingly, 26 April 2010 is a business day as per s. 10 of the NGL.

If APT Allgas does not nominate a final averaging period in its revised proposal, the AER intends to assign a final averaging period that meets these criteria. In this event, the AER will notify APT Allgas in writing of the period it will apply. For the purpose of calculating relevant WACC parameters for this draft decision, the AER use an indicative averaging period of 20 business days ending 6 January 2011, yielding a nominal risk free rate of 5.68 per cent.

5.4.7 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 APT Allgas'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.[68]

5.5 Conclusion

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

5.6 Required amendments

Before its access arrangement proposal can be accepted, APT Allgas 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.

[68] AER, *WACC review final decision*, May 2009, pp. 111–125.

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

Parameter	
Nominal risk–free rate (%)	5.68
Inflation (%)	2.52
Real risk–free rate (%)	3.08
Equity beta	0.8
Market risk premium (%)	6.0
Debt risk premium (%)	3.93
Gearing (%)	60
Cost of debt (%)	9.61
Cost of equity (%)	10.48
Nominal vanilla WACC (%)	**9.96**

6 Taxation

The AER has accepted the post-tax approach proposed by APT Allgas for the access arrangement as it is consistent with the AER's usual approach. It has also accepted the way that taxation is to be calculated (including the use of a 30 per cent corporate tax rate), the opening tax asset base as at 1 July 2011 and the tax asset lives proposed by APT Allgas. These matters were investigated by the AER and found to have been appropriately determined by APT Allgas.

No tax loss carried forward is expected as at 1 July 2011. The AER reviewed APT Allgas's assessment of its tax loss carried forward and considered it unlikely that there would be any tax loss to be carried over to the access arrangement period.

The AER rejected APT Allgas's proposed approach to capitalised overheads as it is inconsistent with the way the opening asset base was determined.

APT Allgas'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 determined that no forecast tax allowance is required for the access arrangement period. This result is largely explained by the AER's draft decision to require APT Allgas to expense its capitalised overheads. It also reflects the revised revenue and cost figures presented in the various chapters of this draft decision.

6.1 Introduction

This chapter provides the AER's assessment of APT Allgas's proposed approach to establishing an allowance for taxation for the access arrangement period. No submissions were received on APT Allgas's proposed tax allowance.

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

APT Allgas proposed a post-tax approach for the access arrangement period.[1]
APT Allgas proposed calculating the cost of corporate income tax for each regulatory year (ETC_t) using the following formula:[2]

$$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$$

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1 APT Allgas, *Access arrangement submission*, September 2010, p. 78.
2 APT Allgas, *Access arrangement submission*, September 2010, p. 78.

Where:

ETI_t is an estimate of the taxable income for regulatory year t that would be earned by a benchmark efficient entity as a result of the provision of regulated services if such an entity, rather than the service provider, operated the business of the service provider, such estimate being determined in accordance with the AER's post-tax revenue model

r_t is the expected statutory income tax rate for that regulatory year assumed to be 30 per cent

γ (gamma, the assumed utilisation of imputation credits) is deemed to be 0.2.

APT Allgas proposed an opening tax asset base (TAB) as at 1 July 2011 of $113 million.[3] A break down of APT Allgas's proposed opening TAB is set out in table 6.1.[4]

Table 6.1: APT Allgas's proposed tax asset base as at 1 July 2011

Asset Category	Tax value ($m, nominal)	Tax Remaining Lives (yrs)	Tax Standard Lives (yrs)
Network Pressure Control Facilities	14.1	15.7	20.0
HP Steel Mains	20.7	9.2	20.0
Distribution Mains	62.8	8.1	20.0
Tariff Metering Equipment	11.9	6.1	15.0
SCADA & Telemetry	1.4	0.9	5.0
IT	0.2	0.1	3.0

Source: APT Allgas's PTRM in an email to the AER, *RE: Confidential information and material outstanding*, 7 October 2010.

APT Allgas engaged Deloitte to review the process it had undertaken to calculate the opening TAB as at 1 July 2011.[5] Deloitte did not identify any significant issues with APT Allgas's opening TAB.[6]

APT Allgas did not provide an analysis of whether it had any tax loss carried forward. In response to an inquiry from the AER, APT Allgas subsequently provided an analysis that showed there was not tax loss carried forward.[7] APT Allgas's tax approach expenses overheads that it capitalises in its regulatory capital base. It has removed these capitalised overheads from the TAB during the earlier access arrangement period and expensed them in the tax loss carried forward calculation.

3 APT Allgas, *Access arrangement submission*, September 2010, p. 86.
4 This break down is not as extensive as for its regulatory capital base.
5 APT Allgas, *Access arrangement submission, Attachment 7.1*, September 2010.
6 APT Allgas, *Access arrangement submission, Attachment 7.1*, September 2010, p. 2.
7 APT Allgas, Email to the AER, *RE: AER.APT.10: tax losses carried forward*, 4 November 2010.

APT Allgas proposed an estimate of the use of imputation credits (gamma) of 0.2.[8] As per the approach adopted in recent AER determinations, APT Allgas's approach to estimating gamma was to separately estimate 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). APT Allgas submitted a range for gamma between zero and 0.4 with a point estimate of 0.2. APT Allgas submitted a Synergies report to support its gamma estimate, which recommended a payout ratio of 70 per cent and utilisation rate range of 0 to 0.57. The main arguments raised in support of APT Allgas's proposal are:

- the AER's estimate of a 100 per cent payout ratio implies that credits retained within the firm are fully valued. Synergies identifies a number of issues with this assumption

- the Beggs and Skeels (2006) study relied on by the AER has not be subjected to the same level of scrutiny as the alternative study produced by SFG, which has been extended and enhanced in previous review processes yet has been consistently rejected by the AER

- 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's has continued to rely on the Handley and Maheswaran (2008) tax statistics analysis despite Synergies' assertion that such analysis cannot be used to value theta.[9]

APT Allgas submitted that if the AER continues to exclude evidence before it, at worst there is no persuasive evidence to depart from the precedent value of 0.5 for gamma.[10] APT Allgas noted that a number of merit 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.[11]

Table 6.2 sets out APT Allgas's forecast tax allowance for the access arrangement period. These forecasts reflect all the proposals that impact on the revenues/expenses that APT Allgas expects to earn/incur over the access arrangement period.

Table 6.2: APT Allgas's proposed tax allowance ($m, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Tax	2.5	2.4	2.2	2.1	2.5

Source: APT Allgas, *Access arrangement submission*, September 2010, p. 87.

8 APT Allgas, *Access arrangement submission*, September 2010, pp. 72–75.
9 APT Allgas, *Access arrangement submission*, September 2010, pp. 72–73.
10 APT Allgas, *Access arrangement submission*, September 2010, p. 75.
11 APT Allgas, *Access arrangement submission*, September 2010, p. 72.

6.4 AER's consideration

The AER accepts APT Allgas's proposed post-tax approach for the access arrangement period (r. 72(1)(h) of the NGR). This approach has been adopted in all previous AER gas and electricity distribution decisions. The alternative pre-tax approach has not been used by the AER to date.

In assessing the forecast tax allowance proposed by APT Allgas, the AER has reviewed the proposed taxation calculation and the components that form part of that calculation, including:

1. the opening tax asset base, used to determine tax depreciation
2. the tax asset lives, used to determine the rate of tax depreciation
3. whether there is any tax loss carried forward from the earlier access arrangement period that needs to be offset against future tax claims
4. the treatment of capitalised overheads
5. 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 this draft decision will require the forecast tax allowance to be revised.

6.4.1 Opening tax asset base

There was no existing TAB for APT Allgas that could be rolled forward from the earlier access arrangement period to establish the opening TAB as at 1 July 2011. While the QCA used a post-tax approach for its building blocks assessment, this approach used the regulatory capital base to estimate tax depreciation. Accordingly, APT Allgas had to develop a TAB for the first time. This task was complicated by the fact that the pipeline network changed ownership in November 2006. Energex was the previous owner of the pipeline network and APT Allgas has no detailed knowledge of Energex's tax approach.

The approach adopted by APT Allgas to setting the taxation asset base reflects the approach outlined by the AER in its issue paper on transitioning from pre-taxation to post-taxation frameworks.[12] APT Allgas reconstructed the opening TAB as at 1 July 2001 for the Allgas entity. It then used the tax values associated with the Allgas entity to roll forward this TAB. The AER reviewed Deloitte's assessment of APT Allgas's proposed TAB as at 1 July 2011 and the assumptions that had been used to reconstruct the TAB as at 1 July 2001. The AER agrees that there are no significant issues with the approach adopted by APT Allgas to determine the TAB. Accordingly, the AER accepts APT Allgas's proposed TAB as at 1 July 2011.

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

6.4.2 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, and

2. the remaining tax asset lives of existing assets.

The tax asset lives were reviewed by Deloitte as part of its assessment of APT Allgas's proposed opening TAB. The AER has reviewed these lives and Deloitte's assessment and finds no issue with the tax asset lives as proposed. The standard tax lives proposed by APT Allgas are consistent with the requirements of the *Income Tax Assessment Act 1997*. From 1 July 2002, the effective lives of gas distribution assets are subject to a statutory cap of 20 years.[13] APT Allgas's proposed standard tax lives are consistent with these caps. Therefore, the AER accepts the standard tax lives proposed by APT Allgas. The AER also accepts the remaining asset lives proposed by APT Allgas. These lives have been affected by the statutory cap that was introduced and which has resulted in the assets being depreciated at an accelerated rate for tax purposes since 2002.

6.4.3 Tax loss carried forward

The AER reviewed APT Allgas's analysis of whether it had any tax loss carried forward as at 1 July 2011. The analysis covered the period 2006-07 to 2009-10 and showed that there was no tax loss carried forward. Despite not presenting a calculation for 2010-11, the positive tax payments over the preceding years (with the exception of 2006-07) indicate that a tax loss in 2010-11 is unlikely. Therefore, the AER is satisfied that no tax loss carried forward needs to be accounted for in the assessment of APT Allgas's forecast tax allowance.

6.4.4 Capitalised overheads

APT Allgas excluded $42 million in capitalised overheads from its opening TAB of $113 million as at 1 July 2011.[14] It did so based on the argument that overheads are expensed for tax purposes. The lower TAB means tax depreciation going forward is lower and consequently the tax allowance is higher (that is, there are lower tax expenses to offset against expected revenues). Going forward, however, APT Allgas has included capitalised overheads in the TAB and is depreciating them. The level of tax depreciation associated with these overheads is significantly less than if the overheads were expensed. The result is that APT Allgas receives a higher tax allowance compared to the alternative of expensing the overheads over the access arrangement period.

The positions adopted by APT Allgas across the two access arrangement periods are inconsistent in terms of the treatment of capitalised overheads for tax purposes.[15] It

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13 Australian Taxation Office, *Taxation Ruling TR 2010/2 – 'Income tax: effective life of depreciating assets'*, 2010, p.10.

14 APT Allgas, Email to the AER, *AER.APT.2: Questions regarding tax,* 15 October 2010.

15 Its treatment of overheads for the capital base is consistent across the both access arrangement period with these overheads being capitalised and included in the capital base.

acknowledged this inconsistency, but argued that the AER's PTRM is not set up to expense capitalised overheads for tax purposes:[16]

> The 2011-16 TAB roll forward is incorrect, in that it includes overheads that cannot be capitalised for tax purposes. This results directly from the structure of the PTRM

The AER considers that there should be no inconsistency across the two regulatory periods in the treatment of capitalised overheads. While the PTRM is indeed set up to roll capitalised overheads into the capital base and TAB in a similar manner, there is no reason why the model could not be amended to allow capitalised overheads in the capital base to be expensed for tax purposes.

The AER accepts APT Allgas's position that capitalised overheads in the capital base should be expensed for tax purposes. The AER altered the PTRM to differentiate between regulatory depreciation and tax depreciation and added a tax expense category of 'capitalised overheads' to the tax assessment. The net effect of this change is a reduction in APT Allgas's tax allowance, other things being equal.

6.4.5 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 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 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 for electricity transmission determinations for which the SORI is applicable. 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 were intended to provide guidance to the gas sector on WACC related matters.

On 13 October 2010 the Australian Competition Tribunal handed down its decision 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 distribution

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[16] APT Allgas, Email to AER, *RE: AER.APT.11: TAB overheads*, 8 November 2010.

determinations in relation to gamma. The Tribunal found errors by the AER in its treatment of the imputation credit distribution ratio and the utilisation rate. However, the Tribunal did not make a determination on the correct value of gamma and directed the AER to undertake further work and seeks a report from the AER in relation to various aspects of the calculation determination of gamma. One element of this work relates to the payout ratio, where 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 gamma aspect of the application for review by Jemena's New South Wales gas network has also been stayed by the Tribunal. The Tribunal is waiting for the outcome of the review of the South Australia and Queensland distribution determinations in relation to gamma before it makes a decision on the gamma to be applied in access arrangement for the Jemena New South Wales gas network.

The further work as part of the Tribunal proceedings is not available for this draft decision however the AER has made this decision on the basis of all relevant information currently before it. The aforementioned Tribunal decisions in relation to gamma may be before the AER when determining the final decision for APT Allgas, and will be taken into account by the AER at that time if available.

The following sections summarise the AER's responses to APT Allgas's arguments according to the following major areas:

- overall considerations with respect to gamma
- estimation of the payout ratio
- use of dividend drop off studies to estimate theta
- use of tax statistics to estimate theta.

6.4.5.1 Overall considerations on gamma

Determining the value of gamma is extremely difficult as it requires various assumptions at both the theoretical and empirical levels, and is also subject to other issues in the development and interpretation of empirical evidence.

The AER and other regulators have estimated equity returns (of which gamma forms part) using the capital asset pricing model, under which one must determine the value of imputation credits to the particular (marginal) investor(s) that sets prices and returns in the relevant market. The residence of this investor is a crucial assumption one must make as an Australian domestic investor will value imputation credits whereas a resident in a country without a dividend imputation system would not value credits at all. During the WACC review the AER adopted a domestic CAPM framework which recognised foreign investors to the extent they influenced market outcomes.

Estimation of gamma is typically done by separately estimating the ratio of credits generated to those that are paid out, and then the utilisation rate of these distributed credits (theta). Many studies have attempted to infer the value of theta from changes

in share prices on ex-dividend days. These studies are subject to numerous issues given the many other known and unknown factors that affect share prices, the variety of measurement techniques available and the influence of particular data examined. Interpretation of results from dividend drop-off studies is also problematic given differences in the personal tax arrangements of individual investors and their differing risk perceptions regarding trading around the ex-dividend date.

Other studies attempt to infer a value of theta by examining data from the ATO which is subject to issues of interpretation given the particular conceptual framework adopted.

Empirical evidence relating to the payout ratio has also been the subject of debate given the practice of companies retaining imputation credits and questions about whether and how these are valued by investors.

The method adopted by the AER to derive an estimate of gamma in the SORI was to assume a payout ratio of 100 per cent. The AER's estimate of theta was obtained by averaging the values derived from the Handley and Maheswaran tax statistics study (0.74) and from the Beggs and Skeels dividend drop off study (0.57). The AER took a simple average of these two values to arrive at a theta value of 0.65 on the basis that both methodologies were somewhat uncertain in terms of providing a point estimate.[17]

The resulting theta value of 0.65 was then multiplied by the assumed payout ratio of 100 per cent to derive a gamma estimate of 0.65.

6.4.5.2 Estimating the payout ratio

As noted above, an ongoing issue in relation to the payout ratio is the practice of companies to not distribute all imputation credits that are created each year. The AER has acknowledged its conclusions in the WACC review regarding a 100 per cent payout ratio were based on a misinterpretation of data presented during the WACC review. The AER accepts that estimates of a payout ratio of approximately 70 per cent reflect total or average observations over the various time periods considered, whereas during the WACC review the AER interpreted these values to be the amount of all imputation credits created in a given year to be distributed to shareholders in that same year. The correct interpretation of these values means that the proportion of credits in franking account balances (which are subjected to time value decay) is not simply 30 per cent of total credits generated every year and that the 70 per cent value includes franking credits generated in a year and paid out in the same year, as well as franking credits generated in previous years. That is, there is no constant or predictable relationship between the time a credit is generated and when it is paid out.

However, contrary to APT Allgas's and Synergies' arguments, the AER does not consider this evidence supports an assumption that retained credits have zero value. There are strong theoretical grounds to support the conclusion that investors place some value on retained credits and reasonably expect that this value may eventually be passed back to them. A payout ratio of approximately 70 per cent implicitly

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[17] AER, *Final decision, WACC parameters,* May 2009, p. 468.

assumes retained credits (which as at 2007 amounted to $148 billion for Australian businesses[18]) are worthless, which the AER considers to be an extreme assumption.

For the purposes of APT Allgas's access arrangement period, the AER acknowledges, however, that it is unlikely that there would be a significant payout of retained imputation credits in the immediate future.

Based on these considerations, the AER concludes that:

- consistent with previous decisions, the estimated value of the payout ratio is within a range of 70 to 100 per cent
- the 70 per cent payout ratio estimated from various studies reflects the average payout ratio. These studies do not provide any information regarding the value of retained credits
- the view that retained credits have value to shareholders and will therefore be eventually distributed is supported by the AER's consultants, and is also supported on theoretical grounds given the rational expectation that businesses will return this value to shareholders
- the empirical evidence currently before the AER supports a value of the payout ratio of 70 per cent, which the AER has adopted as the best estimate possible under the current circumstances in accordance with r. 74(2) of the NGR.

6.4.5.3 Use of dividend drop-off studies to estimate theta

Dividend drop off studies attempt to infer a value of the imputation utilisation rate by observing changes in share prices on ex dividend dates, then decomposing this change into the implied market value of dividends paid and any attached imputation credits. There has been ongoing debate since the AER's WACC review about the study relied on by the AER (Beggs and Skeels) and alternative studies presented and revised by SFG that the AER has not relied on.

The AER acknowledges that it has not been possible to apply the same level of scrutiny to the Beggs and Skeels dividend drop off study as to SFG's studies. However the AER has consistently maintained that the ex ante filtering approach adopted by Beggs and Skeels is superior to the ex post and arbitrary method employed by SFG. The different filtering methods employed undermine the reliability of SFG's estimates and also magnify issues associated with multicollinearity.

The AER recently re-examined SFG's data in the context of its final decision for the Victorian electricity distribution network service providers, which illustrated the sensitivity of SFG's theta estimates to its filtering approach and validated the AER's reluctance to rely on the study for this reason.

The AER replicated the result of a 0.23 value of theta from SFG's February 2010 study and applied the Cook's D statistic to interrogate the SFG 2010 data set. The most influential observation identified was AngloGold Ashanti (AGG), with a

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[18] Synergies, *Estimating a WACC for the APT Allgas Distribution Network*, September 2010, p. 79.

Cook's D statistic of 1.59. AGG is a CHESS Depository Interest (CDI) and represents an interest in a foreign company. For a CDI it is difficult to isolate the share price change effect due to the stock going ex-dividend from other factors and this may represent a reasonable economic justification to exclude the AGG observation from the SFG data set. In addition, AGG is highly priced and pays high dividend per share, making it influential in the least squares-based regression. The AER conducted a sensitivity analysis of SFG's estimated theta using the following filtering options:

- if one AGG observation (19 February 2001) is excluded, the estimated value of franking credit is increased from 0.227 to 0.432
- if all the 12 AGG observations are excluded from the data, the estimated value of franking credit is increased from 0.227 to 0.506
- if all the top one per cent influential observations (based on Cook's D-statistic) are excluded from the data, the estimated value of franking credit is increased from 0.227 to 0.394.[19]

The AER acknowledges that a thorough examination of SFG's dataset would be a costly and time consuming exercise, however an effort of this magnitude has already been undertaken by Beggs and Skeels.[20]

Multicollinearity is a symptom inherent in all dividend drop-off studies. Given the presence of multicollinearity, measuring the implied value of imputation credits through dividend drop-off studies is uncertain, as it is difficult to isolate the effects of cash dividends and imputation credits. Multicollinearity makes the results of the study more sensitive to a small number of observations within the relevant data set. That is, the presence of multicollinearity underlines the importance of an appropriate data filtering method to remove unreliable observations. The sensitivity of results to a limited number of observations was demonstrated above in relation to SFG's data set. Beggs and Skeels' method of developing economically justified filters and applying these ex ante to the entire data set contrasts from SFG's dividend drop-off study, and therefore multicollinearity is expected to be less of an issue for the Beggs and Skeels study.

The AER maintains its view that the SFG dividend drop off study should not be relied upon and that theta value of 0.57 estimated by Beggs and Skeels is the best available estimate.

6.4.5.4 Issues in estimating theta from tax statistics

Tax statistics provide relevant information for estimating the value of imputation credits. The distribution of franking credits represents a means by which a credit for taxes paid by the company is passed onto shareholders.[21] Investors will utilise such

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19 We assume the same weights applied to sample observations as per SFG February 2010, p. 5.

20 For example, the reported number of ordinary dividend events for Beggs and Skeels (2006) was 5511 after filtering – see Beggs and Skeels, *Market arbitrage of cash dividends and franking credits*, 2006, p. 252. , while SFG's data set (after filtering) consisted of 3201 observations – see SFG, *Response to the AER draft determination in relation to gamma*, January 2010, p. 2.

21 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 17.

credits to offset their taxable income, and reduce their tax liability, to the extent that their tax status and domicile permits. As per its position from the WACC review, the AER considers that the theta estimate of 0.74 derived from the Handley and Maheswaran study is the most reliable estimate available from tax statistics. APT Allgas's arguments do not represent any substantive issues with this study or the AER's use of its estimates.

The Handley and Maheswaran study estimates an aggregate reduction in personal taxes due to the aggregate receipt of franking credits (ignoring the time value loss of money from receipt of the franking credit and receipt of the tax saving.[22] As it is significantly unlikely that credits would be worth more than this amount, the redemption rate represents an upper bound on the value of a distributed imputation credit (theta).

The AER's reliance on tax statistics is consistent with previous advice obtained from McKenzie and Partington who recommend the consideration of information drawn from multiple types of studies when estimating gamma.[23] The AER disagrees with Synergies' argument that tax statistics should be completely ignored in this process simply because it is not a "value based approach".[24]

The AER considers that the estimate of 0.74 would conservatively reflect the time value loss of money, given the lack of appropriate data to undertake a more precise calculation. As per Handley's advice, the AER also concludes that the holding period rule would not have a material effect on the utilisation rates estimated by Handley and Maheswaran. The resulting value of the reduction is likely to be conservative when considering the magnitude of time value loss as described above, and the AER's method of using information from tax statistics to derive a point estimate of theta is a conservative and practical method which recognises the limitations inherent in this type of study. Based on these considerations, the AER maintains that the theta point estimate of 0.74 produced from tax studies is still appropriate.

6.4.5.5 Conclusion on the value of gamma

The AER considers that, based on the material currently available, 0.45 is the best estimate of gamma arrived at on a reasonable basis currently available, as required by r. 74 of the NGR. This is based on an assumed payout ratio of 70 per cent and a theta estimate of 0.65. The estimate of theta reflects the simple average of the values derived from the Beggs and Skeels dividend drop off study (0.57) and the Handley and Maheswaran tax statistics study (0.74). In reaching this conclusion the AER has considered the information submitted by APT Allgas as part of its access arrangement proposal, as well as the advice of the AER's consultants. In summary, the AER considers:

- the true value of the payout ratio is within a range of 70 to 100 per cent, however empirical evidence does not support a value of the payout ratio above 70 per cent

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22 Handley, *Further Issues Relating to the Estimation of Gamma*, October 2010, p. 20.
23 McKenzie and Partington, *Evidence and submissions on gamma*, March 2010, pp. 3–4.
24 Synergies, *Estimating a WACC for the APT Allgas Distribution Network*, September 2010, p. 88.

- given the material currently available, the AER considers that for this draft decision, the theta value of 0.65 is still appropriate

- when the 70 per cent value of the payout ratio is combined with a theta of 0.65, the value of gamma is 0.45.

The AER considers that the adoption of a gamma of 0.45 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 s. 23 of the NGL.

However, the AER notes that the further work as part of the Tribunal proceedings is not available for this draft decision. Any Tribunal decisions on this matter will be taken into account by the AER at the time of its final decision for APT Allgas.

6.4.6 Forecast tax allowance

Due to changes discussed above and the various other changes that affected APT Allgas's proposed revenues/costs, the AER recalculated the forecast tax allowance for the access arrangement period. The AER has determined no tax allowance for APT Allgas for the access arrangement period, as shown in table 6.3. The expensing of overheads for tax purposes largely explains this result.

Table 6.3: AER tax allowance for the access arrangement period ($m, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Tax	0	0	0	0	0

6.5 Conclusion

The AER has accepted the tax approach proposed by APT Allgas. However, due to changes in the treatment of capitalised overheads, gamma and the various other factors that impact on revenues and costs, the forecast tax allowance for the access arrangement period has been revised. The AER considers this revised forecast tax allowance can be included as a building block for revenues under r. 76(c) of the NGR.

6.6 Required amendments

Before its access arrangement proposal can be accepted, APT Allgas 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 the treatment of capitalised overheads as described in section 6.4.4.

Amendment 6.2: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of a gamma of 0.45.

Amendment 6.3: make all amendments necessary in the access arrangement proposal and access arrangement information to take account of the revised tax allowance in table 6.3 of this draft decision.

7 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other costs of a non-capital nature incurred by a service provider in the provision of distribution pipeline services. This expenditure also includes costs incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services.

APT Allgas has applied a base year roll forward method of forecasting opex. It proposed opex of $102 million ($2010–11) over the access arrangement period, representing a real increase of 23 per cent on actual incurred expenditure in the earlier access arrangement period. The increase has been principally substantiated by expected changes in input costs, unaccounted for gas (UAG) and the need for various types of non-base year costs to cover circumstances not reflected in the earlier access arrangement period.

The AER reviewed APT Allgas'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 APT Allgas's proposed opex, and Access Economics to provide expert economic advice on the reasonableness of forecast labour costs.

Having considered this advice together with internal analysis, the AER considers that APT Allgas's proposed opex is not prudent and efficient consistent with the NGR. The AER requires various amendments to APT Allgas's proposal, including replacement of its input cost escalators, a reduction in the price assumptions used to derive UAG costs, and amendments to various proposed step changes. Overall, these result in the AER accepting $93 million ($2010–11) in opex over the access arrangement period, which represents a 9 per cent decrease on proposed expenditures. The accepted amount represents a 12 per cent increase in real terms compared to expenditure over the earlier access arrangement period.

7.1 Introduction

This chapter sets out APT Allgas's operating expenditure proposal, and the AER's consideration of the proposal and submissions from interested parties.

7.2 Regulatory requirements

Rule 91 of the NGR provides that operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

The access arrangement information for an access arrangement proposal must include operating expenditure (by category) over the earlier access arrangement period and a

forecast of operating expenditure over the access arrangement period and the basis on which the forecast has been derived.[1]

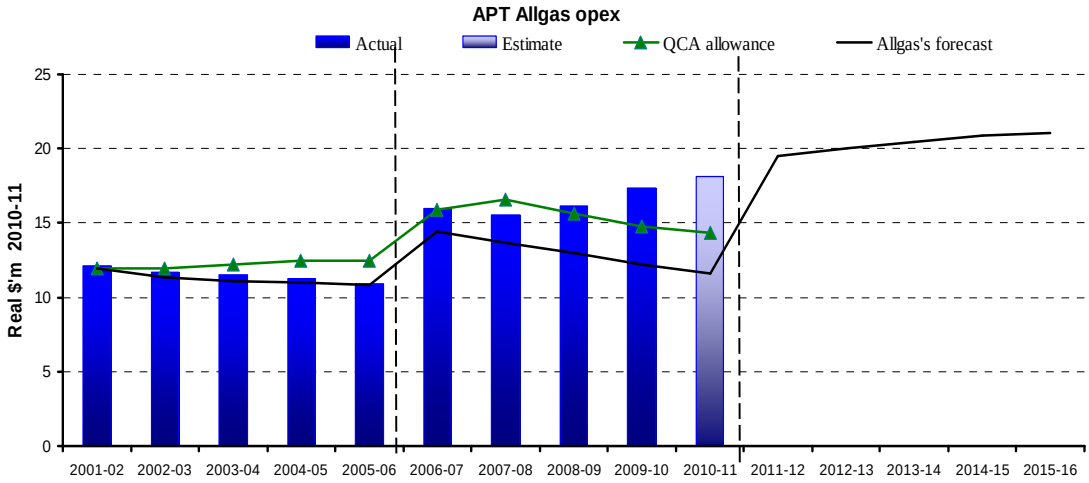
Any a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.[2] A forecast or estimate, must be arrived at on a reasonable basis, and must represent the best forecast or estimate possible in the circumstances.[3]

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.[4]

7.3 Access arrangement proposal

Figure 7.1 compares APT Allgas's actual opex with that approved by the previous regulator, the Queensland Competition Authority (QCA) and expenditures proposed to the QCA in the previous reviews.

Figure 7.1: APT Allgas opex – historical (actuals vs forecasts) vs proposed



Source: APT Allgas, *Access arrangement information*, November 2001, pp. 6–8;
QCA, *Allgas & Envestra gas distribution networks: Draft decision*, March 2001, pp. 207–219;
QCA, *Allgas distribution network: Draft decision*, December 2005, pp. 76–82;
Allgas, *Access arrangement information – Allgas Qld Network*, June 2006, p. 4;
APT Allgas, *Access arrangement submission – 01 July 2011-30 June 2016*, 30 September 2010, pp. 91–92.

7.3.1 Earlier access arrangement

APT Allgas overspent on its total opex allowance in the earlier access arrangement period by 7.7 per cent. Table 7.1 disaggregates these expenditures by category and shows that APT Allgas's overspend was driven principally by the categories of UAG and marketing, with an underspend recorded for the operating and maintenance category. However, effective comparisons between actual incurred and approved

1 NGR, r. 72(1)(a)(ii) and r. 72(1)(e).
2 NGR, r. 74(1).
3 NGR, r. 74(2).
4 NGR, r. 72(1)(f).

expenditures are made difficult given the significant differences in cost categorisation between the QCA's final decision and the present proposal. This is largely due to the ownership change of the APT Allgas network in November 2006.[5]

Table 7.1: APT Allgas allowed vs incurred opex over the earlier access arrangement period ($m, 2010-11)[6] [7]

		2006–07	2007–08	2008–09	2009–10	2010–11	Total
Operating & maintenance	Allowed	13.6	14.4	13.6	12.8	12.5	66.8
	Incurred	13.9	10.7	10.6	13.8	14.6	63.6
	Variance (%)	2.2	-25.6	-21.6	7.4	17.0	-4.8
Marketing	Allowed	0.7	0.6	0.6	0.6	0.6	3.2
	Incurred	0.0	2.8	3.2	1.3	1.1	8.3
	Variance (%)	-100.0	325.0	403.3	118.3	75.0	162.7
Unaccounted for gas	Allowed	1.7	1.5	1.5	1.3	1.2	7.2
	Incurred	2.1	2.1	2.4	2.2	2.4	11.3
	Variance (%)	25.3	40.0	61.4	67.7	103.3	56.6
Total operating expenditure	Allowed	15.9	16.5	15.7	14.8	14.3	77.2
	Incurred	16.0	15.6	16.2	17.3	18.1	83.2
	Variance (%)	0.4	-5.9	3.3	17.4	26.6	7.7

7.3.2 Forecasting method

For the access arrangement period, APT Allgas forecast opex by applying the base year roll forward method, which involved the following steps:[8]

1. selecting an appropriate base year in which to measure costs
2. modifying the base-year to ensure that all costs required for future operation of the network are added and all costs not relevant to the future operation of the network are removed
3. modifying the costs to reflect anticipated changes in customer numbers, demand, and input costs
4. modifying the costs to reflect appropriate productivity improvements.

APT Allgas proposed 2009–10 as the base year, submitting that this year was chosen as it represented the most recent financial information and includes realised benefits

5 APT Allgas, *Access arrangement submission*, September 2010, pp. 93–94.
6 The AER has converted nominal dollars into $2010–11 real dollars.
7 APT Allgas, *Access arrangement submission*, September 2010, pp. 91–95.
8 APT Allgas, *Access arrangement submission*, September 2010, pp. 101–102.

of the synergies the APA Group has obtained through joint management of the APT Allgas and Envestra Queensland networks.[9]

7.3.3 Forecast operating expenditure

APT Allgas's forecast opex for the access arrangement period is set out in figure 1. From this figure it is evident that for this access arrangement, like in its previous proposal to the QCA, APT Allgas has proposed a significant step increase in opex. APT Allgas's total opex proposal represents an 23 per cent increase on total incurred opex and a 32 per cent increase on total approved opex in the earlier access arrangement period.

Table 7.2 disaggregates APT Allgas's opex proposal by category. As previously noted, comparisons are hampered by inconsistent cost categorisation between the earlier access arrangement period and the access arrangement period.

Table 7.2: Proposed forecast opex for the access arrangement period ($m, 2010-11)[10] [11]

	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Controllable costs						
Operating & maintenance	10.5	10.6	10.6	10.7	10.8	53.2
Marketing	1.7	1.7	1.7	1.8	1.8	8.7
Administration & strategic planning	0.7	0.9	0.9	1.1	1.1	4.8
Non-controllable costs						
Customer services	0.9	0.9	1.0	1.0	1.1	4.9
Unaccounted for gas	2.5	2.6	2.9	2.9	2.9	13.8
Government charges	0.5	0.6	0.6	0.6	0.6	2.9
Metering & billing	1.2	1.2	1.2	1.3	1.3	6.3
Corporate costs	1.4	1.4	1.5	1.5	1.5	7.3
Total operating expenditure	**19.5**	**20.0**	**20.5**	**20.8**	**21.0**	**101.8**

APT Allgas's previous and forecast opex did not include debt raising costs, proposing that these costs be included in the overall WACC. The AER considers that such costs should be categorised as an opex item. While all references in this chapter to opex 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 APT Allgas's proposed debt raising costs is set out in appendix F.

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9 APT Allgas, *Access arrangement submission*, September 2010, p.103.
10 The AER has converted nominal dollars to 2010–11 real dollars.
11 APT Allgas, *Access Arrangement Submission*, September 2010, pp. 137–138.

7.4 Submissions

The AER received a submission from Origin Energy questioning the reasonableness of APT Allgas's proposed network development expenditure and whether APT Allgas as the distributor is best placed to deliver the programs within this expenditure.[12]

7.5 Consultant review

The AER engaged Wilson Cook, engineering consultants, to review whether the technical aspects of APT Allgas's proposed opex are prudent and efficient. Wilson Cook reviewed APT Allgas's opex performance in the earlier access arrangement period to provide context to the forecast expenditures, and assess the selection of the base year and the forecast expenditures as proposed.

Wilson Cook noted that actual opex in the earlier access arrangement period was 7.5 percent higher than the approved level, or 2.8 percent higher if expenditure on UAG is removed, with APT Allgas noting that changes in its cost structure occurred during the period, after the change of its ownership.[13]

Wilson Cook considered the base year level of expenditure to be efficient, based on its analysis of comparative opex data for year 2008–09.[14] In regard to forecast opex, Wilson Cook made the following key recommendations:

- adjustments are required in some of the proposed step changes
- the volumetric level of UAG that APT Allgas proposed be considered efficient
- APT Allgas should re-apply its opex real cost escalation using additional factors to represent all the costs of the business as opposed to using a labour index alone.

7.6 AER's consideration

7.6.1 Base year selection

APT Allgas proposed 2009–10 as an efficient base year for forecasting opex in the access arrangement period, except for the items of UAG and leak repair costs.[15]

The starting point when applying a base year roll forward method of forecasting expenditure, also commonly referred to as the revealed efficient cost method, is the selection of a base year from a series of actual expenditure data. The general rationale behind the adoption of this method is that many opex items are largely of a recurring nature—requiring only escalation for changes in input costs or scale, or step changes for regulatory or business environment alterations.

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12 Origin, *Submission on Envestra (Qld) and APT Allgas access arrangement proposals*, 26 November 2010, pp. 2–3.

13 Wilson Cook, *Review of expenditure of Queensland & South Australian gas distributors: APT Allgas Energy Pty Limited*, December 2010, p. 2.

14 Wilson Cook, *Report – APT Allgas*, December 2010, p. 2.

15 APT Allgas, *Access arrangement submission*, September 2010, p. 103.

However, the rationale is based on various assumptions. Firstly, that earlier expenditure can be used as an indicator of likely future expenditure. Secondly, that the base year actually reflects efficient expenditure in a previous period. To test these assumptions, consistent with previous decisions, a number of conditions are to be considered, including:

- The base year should not include substantial non-recurrent expenditure—such expenditure would not be reflective of expenditure to be incurred over the forecast period. Further, it would be a form of double counting if a business also proposed opex related to non-base year costs of a non-recurrent nature.

- The expenditure should reflect actual rather than forecast or unrealised expenditure—to reduce the possibility of artificially inflated expenditure figures.

- The base year should be as close as possible to the forecast period—to present an accurate reflection of a business' operating and organisational circumstances.

Further, and importantly, the AER needs to be confident that the expenditure realised in the base year was efficient. This can be done by comparing its level with that realised in other years of the earlier access arrangement period, and between businesses if such data is available.

These conditions need not all be met, but rather considered on balance as a basis on which to assess the base year's consistency with the requirements of r. 91 of the NGR.

The AER accepts that on balance, the reasons submitted by APT Allgas for the selection of 2009–10 as the base year are appropriate.

Total opex for 2009–10 was reported as being lower than the following year but higher than each prior year of the earlier access arrangement period. While this internal comparison raises some concern, certain circumstances might be adversely influencing this figure. Since the sale of Allgas from its previous owner Energex to the APA Group, APT Allgas underwent a process of adaptation to the APA Group's accounting and other operational systems, progressively making it difficult to compare costs between years. In addition to the ownership change, the APA Group further changed these accounting systems during 2009–10.[16] The AER acknowledges that these combined factors make it difficult to compare data between years in the earlier access arrangement period, particularly those at the beginning of the period. It also lends support to the choice of a base year that is sufficiently close to the start of the access arrangement period so as to be a reliable indicator of current operational and business circumstances and also avoid these data concerns.

The AER has also considered the advice of Wilson Cook, including:[17]

- APT Allgas has made adjustments to the base year to remove non-recurrent items that are not expected to be incurred in the access arrangement period.

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16 APT Allgas, *Access arrangement submission*, September 2010, p.93.
17 Wilson Cook, *Report – APT Allgas*, December 2010, p.32.

- Benchmarking undertaken by Wilson Cook for 2008–09, the most recent year for which data from all companies in its sample was available, indicates that APT Allgas's opex is consistent with industry averages.

- Wilson Cook's analysis of benchmarking submitted by APT Allgas indicates that APT Allgas's opex is in line with industry averages.

Therefore, the AER considers that on balance, 2009–10 is an acceptable indicator of the business and operational circumstances of APT Allgas and should be accepted as an appropriate base year on which to forecast opex in the access arrangement period.

7.6.2 Roll forward forecasts

APT Allgas has applied the base year roll forward method to forecast all opex other than unaccounted for gas and other specific year by year forecast costs. While the AER accepts that the method applied for deriving growth escalation is arrived at on a reasonable basis and produces the best forecast possible as required under r. 74(2) of the NGR, the AER does not accept the input cost escalators proposed by APT Allgas as they are not consistent with r. 74(2).

7.6.2.1 Growth escalators

APT Allgas applied adjustments to certain costs within its base year to account for the impact of growth, including:[18]

- Customer growth - Customer and call-centre services, meter reading, meter leak repairs and costs associated with meter maintenance

- Network growth - Instrumentation, pressure control, pipeline maintenance (in proportion to steel pipeline length), leakage survey, patrols, surveillance, repairs to damaged assets

Wilson Cook reviewed the basis of application of APT Allgas's growth adjustments, considering these to be reasonable. The AER is satisfied that APT Allgas's application of its growth escalators provide a reasonable basis for forecasting the impact of network growth on opex.[19]

7.6.2.2 Input cost escalators

APT Allgas proposed applying one escalator to its capex and three escalators to its opex, as set out in table 7.3 below.[20] [21]

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18 APT Allgas, *Access arrangement submission*, September 2010, p. 122.
19 Wilson Cook, *Report – APT Allgas*, December 2010, pp. 32–33.
20 Escalation rates from 2015-2016 were not included in APT Allgas' access arrangement submission. The AER clarified these figures in correspondence with APT Allgas. See: APT Allgas, *Email to the AER, RE: AER.APT.18, 19 (part) and 20*, 19 March 2010.
21 APT Allgas, *Access arrangement submission*, September 2010, p.47, p. 102.

Table 7.3: APT Allgas's proposed input cost escalators

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
Capex							
Cost Escalation Rates	-	-	0.9	1.3	1.5	1.6	1.3
Opex							
All components	1.1	1.0	0.9	1.3	1.5	1.6	1.3
Regulatory	20.0	20.0	10.0	1.3	1.5	1.6	1.3
Purchased gas	1.5	5.1	8.4	13.7	1.8	0.8	1.1

APT Allgas's 'cost escalation rates' and 'all components' escalators (referred to in this decision as 'general escalators') were composed using data from a previous Access Economics labour cost escalators report prepared for the AER.[22]

APT Allgas applied the 'cost escalation rates' escalator to all capex, and the 'all components' escalator to all opex, except for regulatory costs and UAG.[23] The 'regulatory' escalator is proposed to reflect the forecast cost in government charges and fees, and is applied only to opex in the category of government charges.[24]

AER's consideration

The AER has had regard to the proposed method of deriving input cost escalation forecasts (including the data sources and index measures) and the method of applying these escalators to its opex and capex and whether these met the NGR requirements. The AER considers that for it to be satisfied that forecast opex or capex meet the requirements of r. 91 and r. 79(1) of the NGR, any real cost escalation must be forecast on a reasonable basis, represent the best possible forecast in the circumstances and be supported by a statement of the basis of the forecast.[25]

The NGR does not require that real cost escalation be applied to a business. Under the control mechanism applied to APT Allgas, X-factor elements reflect the path of real costs and CPI is used to transform real costs into nominal values. Where the AER does not accept real cost escalation, input costs are escalated in line with CPI under the control mechanism.

General escalators

The AER does not accept APT Allgas's proposed 'cost escalation rates' and 'all components' escalators as consistent with r. 74 of the NGR. APT Allgas has not demonstrated any basis to support the application of a labour cost forecast across the entirety of opex and capex, including non-labour components, contrary to r. 74.

It is not reasonable to assume that forecast growth in labour costs will reflect the cost pressures on materials. A non-zero escalator for combined materials and labour

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22 Access Economics, *Forecast growth in labour costs – March 2010 report*, March 2010, p. ix.
23 APT Allgas, *Access arrangement submission*, September 2010, p. 47 and p. 102.
24 APT Allgas, *Email response to the AER, AER.APT.06 – Opex*, 29 October 2010.
25 R. 74 of the NGR.

components of expenditure would be inconsistent with the AER's approach to date to real cost escalation. The AER considers that APT Allgas's 'general escalators' have not been estimated on reasonable grounds and do not produce the best forecast possible in the circumstances, as required under r. 74 of the NGR, and therefore should not be accepted.

However, with specific regard to labour costs, it would be reasonable to expect non-zero real cost escalation over the access arrangement period. While the AER agrees that labour escalation should apply, this is on the basis that any such escalators are applied only to the labour cost components of opex and capex. APT Allgas's proposed general escalators demonstrate that it accepts the general methodology applied by Access Economics. However, the AER considers that the Access Economics labour cost report utilised by APT Allgas is now outdated.[26] An update has been prepared for the AER for this access arrangement review. As such the AER considers that for the purpose of forecasting labour costs, the escalators proposed by APT Allgas do not represent the best forecast in the circumstances as required under r. 74(2)(b), and that they should be replaced with Access Economics' most recent update of productivity adjusted real growth in labour costs.

Application of labour escalators

While the AER accepts the notion that labour cost escalation should be applied, APT Allgas did not provide a breakdown of labour and materials costs across its opex and capex proposal. In lieu of these breakdowns, the AER has sought the technical advice of Wilson Cook as to a set of reasonable application rates for both labour and materials across all of APT Allgas's costs. Wilson Cook's advice was that the application rates applied by Envestra in its Queensland network expenditures would be reasonable having reviewed the applied proportions of labour and materials as consistent with industry practice. The AER accepts that these would represent the best estimate of APT Allgas's application rates in the circumstances.[27]

The individual capex and opex categories proposed by Envestra and APT Allgas are not entirely consistent. As such, the AER considers that the best estimate possible in the circumstances is achieved by calculating weighted averages of cost escalator application rates to total opex and total capex costs.[28] These final weightings are set out in table 7.5. The AER considers that Access Economics' forecast productivity adjusted growth in the real labour price index, when applied based on the AER's derived weighted average application rates, produces forecasts arrived at on a

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[26] Access Economics, Forecast growth in labour costs – March 2010 report, March 2010, p. ix.

[27] Wilson Cook, Email to the AER, *Allgas Cost Escalators*, 30 November 2010.

[28] The application rates were calculated as follows:

1. Total cost-category expenditure for the period ÷ total operating/capital expenditure
   e.g. (total network development expenditure ÷ total operating expenditure)
2. Output of (1) * the cost-category application rate for specific cost escalators
   e.g. (output of (1) x application rate of general labour to network development expenditure).
3. For each cost escalator, sum of (2) for all cost-categories in operating/capital expenditure
   e.g. output of (2) + [(total marketing expenditure ÷ total opex) x application rate of general labour to marketing expenditure] + …
4. Perform (3) for each labour cost escalator, for each of operating and capital expenditure
   e.g. application rate of EGW labour to total opex, application rate of EGW labour to total capex, application rate of general labour to total opex etc.

reasonable basis and represents the best forecast possible in the circumstances, as required by r. 74 of the NGR.

Regulatory escalator

The AER considers that APT Allgas's proposed 'regulatory' escalator has not been arrived at on a reasonable basis and does not produce the best estimate possible in the circumstances of its expected increases in regulatory costs over the access arrangement period. The proposed escalator needs to be amended to reflect the likely anticipated increase in costs and to comply with r. 74.

While APT Allgas provided documentation from the Queensland Government Department of Employment, Economic Development and Innovation (DEEDI) to support its proposal that regulatory costs will increase over the access arrangement period,[29] the AER did not find this supported the escalator rates proposed. APT Allgas forecast an increase in real terms of 58.4 per cent in regulatory costs between 2009–10 and 2011–12. From 2012–13, APT Allgas proposed to escalate regulatory costs mirroring the 'all components' escalator. However, contrary to these figures, the documents submitted by APT Allgas suggest that DEEDI has only indicated that an increase of 30 per cent in regulatory fees was to be introduced in 2009–10 in relation to the previous year.[30] While the information submitted by APT Allgas indicates that it will be subject to new yearly inspections and other audits, the advice does not indicate how the fees are to progress over the access arrangement period.

APT Allgas's data for the last two years of the earlier access arrangement period demonstrate that it had already applied a yearly escalation of 20 per cent for increases in regulatory costs. As 2009–10 is the year proposed and accepted by the AER as being the base year, this 20 per cent increase in costs would already be incorporated in APT Allgas's roll forward forecasts. As the base is to be rolled forward, the AER considers that based on the evidence provided, only an additional 8.3 per cent growth in 2011–12 should be accepted, to arrive at the rate of 30 per cent.[31]

Given the information from DEEDI, the AER considers that APT Allgas's regulatory escalator has not been arrived at on a reasonable basis and does not reflect the best estimate of regulatory costs possible in the circumstances as required by r. 74(2)(b). The AER considers that it should be amended such that only an 8.3 per cent increase is added to the first year of the access arrangement period.

AER conclusion on input cost escalators

The AER considers that APT Allgas's proposed real cost escalators have not been estimated on a reasonable basis nor produce the best forecast in the circumstances faced by APT Allgas. In particular, the AER considers:

- applying labour costs to forecast non-labour components of opex and capex is not appropriate
- the report utilised by APT Allgas to escalate labour costs is outdated

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29 DEEDI, *Proposed audit and inspection fee review summary*, March 2010, attached table 1.
30 DEEDI, *Proposed audit and inspection fee review summary*, March 2010, attached table 1.
31 This figure has been arrived at by calculating the effects of compounding the 20 per cent

- the regulatory cost escalator is not estimated on a reasonable basis as it does not reflect the evidence provided as to cost increases.

The AER does not approve APT Allgas's real cost escalators and requires that amendments be made such that:

- labour escalation be only applied to the labour component of opex and capex
- labour escalation can only be reasonably estimated by applying Access Economics' updated forecast on labour costs, as provided for the AER
- labour escalation be applied according to the AER's application rates, unless a more reasonable application method is advanced by APT Allgas.

The AER's amended input cost escalators are set out in table 7.4.

Table 7.4: AER conclusion on APT Allgas's real input cost escalators (per cent)

	2011–12	2012–13	2013–14	2014–15	2015–16
EGW labour	-0.3	0.1	0.2	-0.8	-1.6
General labour	-1.1	-0.7	-0.2	-1.0	-1.7
Construction labour (capex only)	0.7	0.6	0.5	-0.4	-1.2
Regulatory	8.3	0	0	0	0

The AER requires that in the absence of an alternative and reasonable application method that APT Allgas apply labour escalation in accordance with the labour escalators and application rates provided in table 7.5

Table 7.5: AER conclusion on APT Allgas real input cost escalator application rates (per cent)

	Opex	Capex
EGW labour	0.63	0.09
General labour	0.14	0.01
Construction labour	0	0.76

7.6.3 Specific year by year forecasts

7.6.3.1 Unaccounted for gas

The AER does not accept that APT Allgas's forecast UAG opex represents an efficient level of expenditure as required under r. 91 of the NGR. While accepting APT Allgas's forecast UAG volumes, the AER considers its assumption as to gas price is not reasonably based as required under r. 74(2)(a) of the NGR.

UAG is defined by APT Allgas as the volume of gas injected into the distribution system less the volume of gas billed to customers.[32] It submitted that the majority of UAG can be attributed to gas leakages particularly from cast iron and unprotected steel mains and services in its network.

APT Allgas proposed a total of $13.3 million over the access arrangement period in order for it to purchase gas to compensate for gas losses in the network.[33] Its forecast is based on certain assumptions as to the forecast price of gas and the likely volume of UAG that is expected, as set out in table 7.6.

Table 7.6: APT Allgas's proposed UAG opex and assumptions[34]

	2011–12	2012–13	2013–14	2014–15	2015–16
Volume (GJ)			[Text removed - c-i-c]		
Price ($)			[Text removed – c-i-c]		
Total UAG opex ($m)	2.41	2.53	2.80	2.78	2.73

AER considerations

The AER reviewed the volume and price assumptions within APT Allgas's forecast of UAG opex, with Wilson Cook engaged to provide engineering advice on the former.

UAG Volume

Wilson Cook noted that APT Allgas's forecast allowed for a rate of leakage reduction due to its proposed mains replacement program, and appropriately factored in the rate of leakage from the remaining mains. Wilson Cook considered that the assumptions provided have been reasonably based.[35] The AER considers APT Allgas's forecast of UAG volumes to be arrived at on a reasonable basis and represents the best estimate possible in the circumstances, consistent with r. 74 of the NGR.

UAG Price

APT Allgas forecast a price required for it to purchase gas over the access arrangement period to compensate for gas losses. APT Allgas has predominantly based its price on forecasts of delivered gas prices to Brisbane, derived from a report prepared by McLennan Magasanik Associates (MMA) for the Queensland Government's annual gas review.[36]

The MMA report presents a reasonable basis and the best forecast possible of wholesale gas prices delivered to Brisbane. However, the AER considers that APT Allgas has not advanced any justification to substantiate why its addition of a [c-i-

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32 APT Allgas, *Access arrangement submission*, September 2010, p. 90.

33 APT Allgas, *Access arrangement submission: Opex business case – UAG*, September 2010, p. 8 (confidential).

34 APT Allgas, Access arrangement submission: Mains replacement strategic plan, September 2010, p. 13; and APT Allgas, *Access arrangement submission: Attachment 4.8: Opex business cases – UAG*, September 2010, p. 8 (confidential).

35 Wilson Cook, *Report – APT Allgas*, December 2010, p. 32.

36 APT Allgas, *Access arrangement submission: Attachment: APT Allgas UAG cost assumptions*, November 2010, p. 1 (confidential).

c] per cent margin to the MMA forecast delivered price represents a reasonable estimate and produces the best forecast possible in the circumstances as required under r. 74 of the NGR.[37]

In addition, in previous gas distribution decisions, the AER has only approved price assumptions for the purpose of UAG opex based on wholesale delivered gas prices.[38] The AER considers that APT Allgas has not provided evidence to support a departure from this approach in these circumstances.

The AER requires that APT Allgas's forecast UAG opex be amended to reflect only the price forecasts provided in the MMA report, and that the [c-i-c] per cent margin be removed. The result of the AER's required amendments are set out in table 7.7.

Table 7.7: AER conclusion on APT Allgas's UAG opex ($2009–10)

	2011–12	2012–13	2013–14	2014–15	2015–16
Volume (GJ)	[Text removed – c-i-c]				
Price ($)	[Text removed – c-i-c]				
Total UAG opex ($m)	1.91	2.02	2.23	2.21	2.16

7.6.3.2 Non-base year costs

APT Allgas proposed 10 items as being step and scope changes in relation to its base year opex to apply in the access arrangement period representing a total of $10 million ($2010-11), or 10 per cent of total opex. These are referred to here as proposed step changes, or non-base year costs.

AER considerations
The AER considers that any proposal for opex, whether it be contained in a base year or as a step change, necessarily needs to be assessed against the NGR and NGL, in particular r. 91 and r 74, and s. 24 of the NGL.

The AER would expect that as APT Allgas has chosen to apply a base year roll forward method, in which it has also proposed non base year costs such as step changes, any expenditures proposed as being step changes from the base year should reflect certain circumstances and allow the AER to determine if they are indeed reasonable additions to a base year.

Firstly, the AER needs to assure itself that the step changes are to reflect changes in costs that are not reflected in the base year. Secondly, step changes should relate to exogenous changes in costs associated with either changes in the operating environment, or changes resulting from new or modified regulatory obligations. Both of these matters would reflect circumstances in which it is not reasonable to assume

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37 APT Allgas, *APT Allgas UAG cost assumptions*, November 2010, p. 1 (confidential).

38 AER, *Final decision: Jemena Gas Networks, access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015*, June 2010, p. 275; and AER, *Final decision: Access Arrangement proposal ACT, Queanbeyan and Palerang gas distribution network 1 July 2010 – 30 June 2015*, March 2010, p. 85.

that a service provider's base year expenditures will be reflective of future requirements or pressures.

However, the AER has also considered whether any of APT Allgas's proposed step changes, that do not have the characteristics of the second point, are otherwise required in order for APT Allgas to provide pipeline services in a prudent and efficient manner, consistent with the NGR and NGL.

The AER sought the expert advice of Wilson Cook in relation to whether APT Allgas would be a prudent service provider acting efficiently with respect to its proposed step changes. The AER's considerations of each of the individual business cases for these items against the NGR and NGL having regard to the advice of its consultant are set out in table 7.9. Overall the AER considers that 5 of the 10 proposed step and scope changes (non base year costs) are not consistent with the NGR and are not approved. The AER's required amendments are summarised in table 7.8 and detailed in table 7.10.

Table 7.8: AER conclusion on APT Allgas's step and scope changes ($m, 2010–11)

Step and scope changes	2011–12	2012–13	2013–14	2014–15	2015–16	Total
Total APT Allgas proposed	1.79	2.06	2.05	2.07	2.07	10.05
AER amendment	-0.71	-1.02	-1.04	-1.05	-1.09	-4.93
Total AER approved	**1.08**	**1.04**	**1.01**	**1.02**	**0.98**	**5.12**

Table 7.9: AER consideration of APT Allgas's non base year costs ($m, 2010–11)

Item of expenditure	Allgas's proposal	Wilson Cook recommendation	AER consideration
Appointment of revenue protection officer – monitoring and investigating metering anomalies.[39]	0.3	The benefit was claimed to be a resulting reduction in UAG, therefore the expenditure has been shown to be prudent and efficient.[40]	The AER acknowledges that UAG levels are caused by various factors other than leakages. However, while this project was substantiated by the need to investigate matters that have a bearing on UAG, APT Allgas has proposed to the AER a mains replacement program that is supported by assumptions as to the effects on reducing UAG levels and in turn opex for UAG compensation. Further, the AER notes that APT Allgas has had prior experience in developing these assumptions, having undertaken mains replacement programs and dealt with issues of UAG in earlier access arrangement periods. Therefore, the AER considers that APT Allgas has not demonstrated that the expenditure proposed for a revenue protection officer is to be spent investigating matters of which it is not currently aware or which is not otherwise already reflected in the base year. The AER considers that this expenditure is therefore neither prudent nor efficient as required under r. 91 of the NGR.
Replacement of lids on district regulator stations.[41]	0.1	Wilson Cook noted that the original lids have been found inadequate leading to water ingress, and the buckled lids pose a potential public hazard.[42]	The AER accepts Wilson Cook's recommendation that the expenditure is a prudent and efficient response to an identified network safety risk and should be approved as consistent with r. 91 of the NGR.
Bridge crossing maintenance program – installations where high pressure pipelines are fixed to bridges or other structures.[43]	0.9	The program and expenditure is a prudent and efficient response to an identified safety risk.[44]	The AER accepts Wilson Cook's recommendation that the program is a prudent and efficient response to an identified safety risk and therefore that expenditure should be approved as consistent with r. 91 of the NGR.
Condition monitoring of cased pipelines.[45]	1.3	Wilson Cook noted that current practice has been to put certain pipes in casings but the pipes do not have cathodic protection in the casings.[46]	The AER accepts Wilson Cook's recommendation that the program represents a prudent and efficient response to mitigate an identified network safety risk and that it should be approved as being consistent with r. 91 of the NGR.

39 APT Allgas, *Access arrangement submission: Attachment 4.8: Opex business cases – Revenue protection officer*, September 2010, pp. 1–11.
40 Wilson Cook, *Report – APT Allgas*, December 2010, pp. 35–36.
41 APT Allgas, *Access arrangement submission: Attachment 4.8: Opex business cases – Cocon lid replacement*, September 2010, pp. 1–8.
42 Wilson Cook, *Report – APT Allgas*, December 2010, p. 36.
43 APT Allgas, *Access arrangement submission: Attachment 4.8: Opex business cases – Maintenance of bridge crossings*, September 2010, pp. 1–8.
44 Wilson Cook, *Report – APT Allgas*, December 2010, p. 36.
45 APT Allgas, *Access arrangement submission: Attachment 4.8: Opex business cases – Condition monitoring of cased pipelines*, September 2010, pp. 1–12.
46 Wilson Cook, *Report – APT Allgas*, December 2010, p. 36.

Leakage survey and repairs.[47]	2.6	The program and expenditure is a prudent and efficient response to an identified safety risk, and ensures compliance with a regulatory obligation.	The AER accepts Wilson Cook's recommendation that the program is a prudent and efficient response to an identified safety risk and ensures compliance with a regulatory obligation and should therefore be approved.[48]
IT costs – opex associated with the "roadmap initiative" capex project.[49]	0.7	While efficiency improvements have been submitted as resulting from the project, no evidence has been demonstrated as to these efficiencies.	The AER accepts Wilson Cook's advice that as APT Allgas has not demonstrated or quantified the claimed efficiency improvements associated with the project, the expenditure cannot be approved as being efficient as required under r. 91 of the NGR.[50]
Knowledge management – development of a more formal document management process.[51]	0.6	Usually such projects result in significant business efficiency improvements and this was given as one of the project's benefits. However, the expenditure was not demonstrated to be efficient as no allowance was made for efficiency improvements. Recommend the project be rejected.[52]	The AER accepts the advice of Wilson Cook that efficiencies for such a project need to be demonstrated. Further, the AER considers that while knowledge management is good business practice, APT Allgas should already be applying such practices through the earlier access arrangement period and that related costs should be captured in the base year. The AER therefore does not approve APT Allgas's proposed opex on knowledge management as it does not comply with r. 91 of the NGR.

Item of expenditure	**Allgas's proposal**	**AER consideration**
Market rule changes – an additional FTE to support participation in the (STTM).[53]	0.3	The gas Short Term Trading Market (STTM) is to be introduced into Queensland and will place greater emphasis on the quality and reliability of the metering data that participants provide to the market. The AER considers that this expenditure is a prudent and efficient response by APT Allgas to a new external obligation and should be accepted as consistent with r. 91 of the NGR.
Electricity-to-gas hot water changeover program – promotion and provision of incentives for uptake of conversions to gas hot water systems.[54]	2.0	APT Allgas' rationale for this programme is to mitigate falling average residential consumption in Queensland.[55] However, the demand forecasts proposed by APT Allgas, and considered in chapter 9, don't appear to the AER to show evidence of any linkage between this program and demand in the access arrangement period. Also, the AER considers that insufficient evidence has been submitted to demonstrate that the expenditure is indeed efficient. APT Allgas has not provided a substantiated estimate or forecast of likely uptake over the period to warrant the overall expenditure of $2.0 million, nor information

47 APT Allgas, *Access arrangement submission: Attachment 4.8 Opex business cases – Extension of Leakage survey program*, October 2010, pp. 1–7.
48 Wilson Cook, *Report – APT Allgas*, December 2010, p. 37.
49 APT Allgas, *Access arrangement submission: Attachment 4.8 Opex business cases – Roadmap initiatives*, October 2010, pp. 1–28.
50 Wilson Cook, *Report – APT Allgas*, December 2010, pp. 37–38.
51 APT Allgas, *Access arrangement submission: Attachment 4.8 Opex business cases – knowledge management*, October 2010, pp. 1–12.
52 Wilson Cook, *Report – APT Allgas*, December 2010, p. 38.
53 APT Allgas, *Access arrangement submission: Attachment 4.8: Opex business cases – Market rule changes*, September 2010, pp. 1–6.
54 APT Allgas, *Access arrangement submission: Attachment 3.1.2 – Network Development Plan: Electricity to gas hot-water changeover program*, October 2010, pp. 1–12.

		suggesting that the proposed $500 incentive has been based on an economically efficient level and reflects the lowest sustainable cost, as required under r. 91 of the NGR.[56] Further, the program was described as an existing program undertaken in the earlier access arrangement period.[57] As such, it is not evident to the AER the extent to which the proposed expenditure is actually a step change on expenditure currently in the base year. For these reasons, the AER considers that this expenditure does not meet the requirements of r. 74 and r. 91 of the NGR.
Development and deployment of new technology – establishment of a New Technology Group to facilitate deployment of evolving gas technologies.	1.3	Origin Energy in its submission to the AER questioned the appropriateness of such expenditure, suggesting that it was not aware of any new gas technologies in the medium term. It further questioned whether a gas distributor is even best placed to develop or market such technologies.[58] While the program's benefits were submitted in the context of mitigating average consumption in Queensland, the AER cannot find evidence suggesting that a link was advanced by APT Allgas as to the likely impact of these programs on its demand forecast.[59] The business case for this project does not advance a basis on which the likely economic benefits of the expenditure have been assessed and forecast. As such, and in accordance with the requirements of r. 74 and r. 91 of the NGR, the AER does not approve the expenditure for the proposed development and deployment of new technology program.

55 APT Allgas, *Access arrangement submission: Attachment 3.1.2*, October 2010, pp. 1–4.
56 APT Allgas, *Access arrangement submission: Attachment 3.1.2*, October 2010, p. 8.
57 APT Allgas, *Access arrangement submission: Attachment 3.1.2*, October 2010, p. 7.
58 Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, pp. 2–3.
59 APT Allgas, *Attachment 4.8 Opex business cases – Development & deployment of new technology*, October 2010, pp. 1–10.

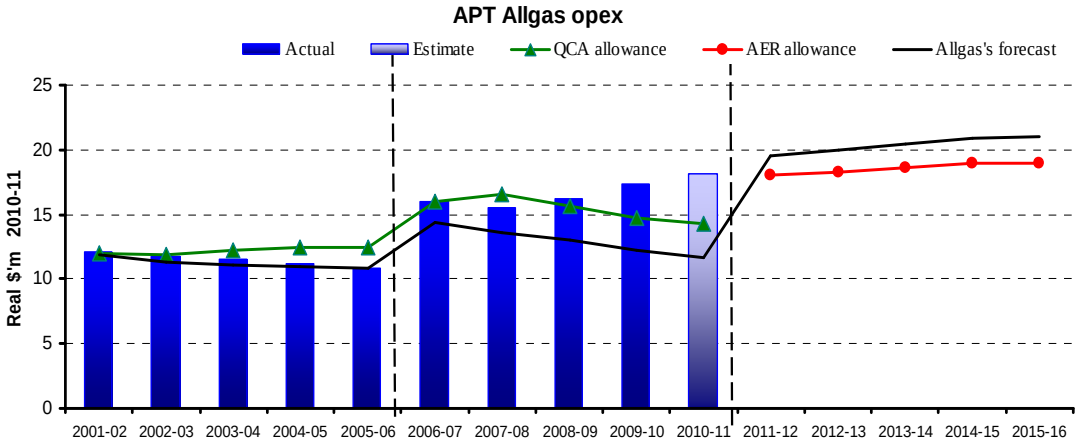
7.7 Conclusion

The AER proposes to not approve APT Allgas's proposed opex as it does not comply with the relevant requirements of the NGR and as such is not consistent with the national gas objective of the NGL. The AER requires APT Allgas to make the amendments set out in section 7.8 of this draft decision.

Overall, the AER approves $93 million in opex over the access arrangement period as consistent with the NGR, which represents a 9 per cent reduction on proposed expenditures. The total approved opex against that proposed is set out in figure 8.2.

At the subsequent access arrangement review, the AER will require that APT Allgas demonstrate that the non base year costs accepted for this access arrangement period have been removed from the year proposed as being the base year.

Figure 8.2: APT Allgas's historic opex vs forecast and allowed



7.8 Required amendments

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 7.10 and in appendix F.

Table 7.10: AER required amendments to APT Allgas's forecast opex

	2011-12	2012-13	2013-14	2014-15	2015-16	Total
APT Allgas forecast operating expenditure	19.48	19.99	20.50	20.81	21.12	101.90
AER specific amendments						
UAG	-0.60	-0.59	-0.58	-0.60	-0.66	-3.04
Revenue and protection officer	-0.05	-0.05	-0.05	-0.05	-0.05	-0.25
Electricity to gas hot water changeover	-0.40	-0.40	-0.41	-0.41	-0.42	-2.04
Development and deployment of new technology	-0.26	-0.27	-0.27	-0.27	-0.28	-1.33
IT roadmap opex	0.00	-0.15	-0.16	-0.17	-0.18	-0.68
Knowledge management	0.00	-0.15	-0.15	-0.15	-0.16	-0.63
Total AER specific amendments	**-1.31**	**-1.62**	**-1.63**	**-1.66**	**-1.75**	**-7.98**
Forecast operating expenditure less specific amendments	18.17	18.37	18.87	19.15	19.37	93.93
Effect of input cost escalator amendments	-0.10	-0.14	-0.22	-0.19	-0.40	-1.05
Total AER approved operating expenditure	**18.07**	**18.23**	**18.66**	**18.96**	**18.96**	**92.88**

8 Total revenue

The AER has calculated a total revenue requirement for APT Allgas over the access arrangement period of $345 million, compared to $372 million proposed by APT Allgas. The main reasons for this difference are the reductions required by the AER to APT Allgas's proposed WACC, forecast capex and forecast opex for the access arrangement period.

Based on the AER approved revenues and demand forecasts, the tariffs for haulage services for both volume and demand customers are expected to rise in real terms by about 3.6 per cent per annum (on average). The tariffs for ancillary services will increase each year only by the rate of change in CPI.

8.1 Introduction

This chapter provides the AER's estimation of annual revenue requirements for APT Allgas for the provision of pipeline services for each year of the access arrangement period. It draws on the adjustments to APT Allgas's proposed building block components discussed in the preceding chapters. No submissions were received on APT Allgas's proposed revenue requirement.

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. The building block components are:

- a return on the projected capital base for the year
- depreciation on the projected capital base for the year
- forecast operating expenditure for the year
- the estimated cost of corporate income tax for the year (if applicable)
- any penalty/reward from the operation of an incentive mechanism.

8.3 Access arrangement proposal

APT Allgas proposed a total revenue requirement of $372 million over the access arrangement period.[1] The break down of this amount (including the amount related to ancillary services) is provided in table 8.1. This table also provides information on APT Allgas's proposed smoothing of these revenues and the resulting X factors for both haulage and ancillary services. The same X factors (that is, a single price path)

[1] APT Allgas, *Access arrangement submission*, September 2010, pp. 145–148.

were proposed by Envestra to apply to all volume and demand customers of haulage services.

Table 8.1: APT Allgas's proposed annual revenue requirement and X factors ($m, nominal)

	2011–12	2012–13	2013–14	2014–15	2015–16
Return on capital	43.5	46.0	48.7	51.6	54.6
plus regulatory depreciation[a]	1.9	1.0	0.9	0.9	1.3
plus operating and maintenance	20.0	21.1	22.1	23.1	23.9
plus corporate income tax	2.5	2.4	2.2	2.1	2.5
Total revenue	**67.8**	**70.5**	**73.9**	**77.6**	**82.2**
less forecast capital contributions	0.6	0.6	0.6	0.7	0.7
less ancillary services revenue	0.6	0.6	0.7	0.7	0.7
Total haulage services revenue	**66.6**	**69.3**	**72.6**	**76.3**	**80.8**
Smoothed haulage services revenue	**58.7**	**66.3**	**74.9**	**82.5**	**86.7**
X factors[b]					
Haulage reference services (%)	-11.27	-8.00	-8.00	-5.00	0.00
Ancillary service fees (%)	0	0	0	0	0

Source: APT Allgas, *Access arrangement submission*, September 2010, pp. 145–148.
APT Allgas, Email to the AER, *APT Allgas demand summary*, 7 October 2010.
(a) Regulatory depreciation includes the negative depreciation impact of inflation on the capital base.
(b) Negative values for X indicate real price increases under the CPI–X formula.

8.4 AER's consideration

In making this draft decision, the AER has had regard to the national gas objective and the revenue and pricing principles in ss. 23 and 24 of the NGL respectively. The AER has examined the various components of APT Allgas's proposed revenue requirement against these provisions as well as the requirements of the NGR. The assessment of the various revenue components (both the service provider's proposal and any alternative value determined by the AER) are presented in the various chapters of this draft decision.

One outstanding matter not discussed in other chapters is the ancillary services revenues (for special meter reads, disconnections and reconnections) forecast by APT Allgas. The AER reviewed APT Allgas's calculation of these figures and considers them to be reasonable. The forecasts are based on APT Allgas's proposed ancillary services tariffs for 2010–11, historical demand (adjusted for expected

growth in these services) and the expected increases in these tariffs over the access arrangement period.[2]

Bringing the various revenue components together, the AER's draft decision results in a total revenue requirement over the access arrangement period of $345 million, compared to $372 million proposed by APT Allgas. The main reasons for this difference are the reductions required by the AER to APT Allgas's proposed:

- WACC for the access arrangement period
- opex for the access arrangement period
- tax allowance for the access arrangement period.

The total revenue requirement is smoothed and converted to tariffs using the forecast demand figures approved by the AER. The annual revenue requirements and annual price changes (as indicated by the X factors) are summarised in table 8.2. The AER accepts that the same X factors will apply to all volume and demand customers, as discussed in chapter 11.

[2] APT Allgas, *Access arrangement submission*, September 2010, pp. 152–153.

Table 8.2: AER's conclusion on APT Allgas's annual revenue requirement and X factors ($m, nominal)[a]

	2011–12	2012–13	2013–14	2014–15	2015–16
Return on capital	42.2	45.0	47.6	50.3	53.1
plus regulatory depreciation[b]	-1.8	1.5	1.4	2.1	2.4
plus operating and maintenance	18.8	19.5	20.4	21.3	21.8
plus corporate income tax	0	0	0	0	0
Total revenue	**59.3**	**66.0**	**69.4**	**73.7**	**77.3**
less forecast capital contributions	0.6	0.6	0.6	0.7	0.7
less ancillary services revenue	0.6	0.6	0.7	0.7	0.7
Total haulage services revenue	**58.0**	**64.7**	**68.1**	**72.3**	**75.9**
Smoothed haulage services revenue	**57.4**	**62.7**	**67.8**	**73.4**	**78.6**
X factors[c]					
Haulage reference services (%)	-7.89	-4.00	-3.00	-3.00	-2.00
Ancillary service fees (%)	0	0	0	0	0

(a) Numbers may not add due to rounding.
(b) Regulatory depreciation includes the negative depreciation impact of inflation on the capital base.
(c) Negative values for X indicate real price increases under the CPI–X formula.

The X factors indicate there will be real increases of about 4.0 per cent per annum (on average) in haulage reference service tariffs over the access arrangement period. There are no real price changes for ancillary services fees, which will be indexed by the change in CPI each year.

8.5 Conclusion

The AER does not approve the annual revenue requirements proposed by APT Allgas as these do not comply with r. 76 of the NGR.

8.6 Required amendments

Before its access arrangement proposal can be accepted, APT Allgas must make the following amendment:

Amendment 8.1: make all amendments necessary in the access arrangement proposal and access arrangement information in order to incorporate the values noted in table 8.2 of this draft decision.

Part B – Tariffs

9 Demand forecasts

Demand forecasts are used to calculate the reference tariffs and also influence forecast capital and operating expenditure linked to network growth.

The AER considers APT Allgas's general approach to demand forecasting is reasonable.

However, the AER considers that two amendments are needed in order for the forecasts to be accepted. First, the forecasts of volume business customer numbers should be adjusted to reflect lower levels of expected business connections. Second, residential consumption in the western region should be adjusted to account for weather sensitive space heating demand.

The AER considers the forecasts for volume business customer numbers and residential consumption in the western region should be amended to the levels set out in tables 9.3 and 9.5 respectively. This represents a six per cent upward revision to the total residential consumption forecast, and a seven per cent downward revision to volume business customer numbers forecast over the access arrangement period.

9.1 Introduction

This chapter sets out the AER's consideration of the gas demand forecasts submitted by APT Allgas to apply over the access arrangement period.

9.2 Regulatory requirements

Rules 72(1)(a)(iii) and 72(1)(d) of the NGR provide that the access arrangement information for a full access arrangement proposal for a distribution pipeline must include:

- usage of the pipeline over the earlier access arrangement period showing, for a distribution pipeline, minimum, maximum and average demand, and customer numbers in total and by tariff class

- to the extent that it is practicable, a forecast of pipeline capacity and utilisation of pipeline capacity over the access arrangement 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 explaining 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 Access arrangement proposal

APT Allgas proposed to separate its customers into two tariff classes. The volume customer class (Tariff V) includes residential and small business customers with

annual consumption less than 10 TJ. The demand customer class (Tariff D) includes large business customers with annual consumption greater than 10 TJ.[1]

The following factors were identified by APT Allgas as influencing gas demand over the access arrangement period:[2]

- performance of the Queensland economy
- dwelling and population growth
- more stringent building code improving the energy efficiency of new dwellings
- APT Allgas marketing programs
- government policy initiatives
- efficiency gains in gas appliances.

APT Allgas developed its residential and small business customer numbers forecasts based on the historical disconnection rate and Housing Industry Association (HIA) long term outlook for new dwelling starts in Queensland.[3]

Average consumption is forecast by APT Allgas to decline over the access arrangement period. This is driven by efficiency gains in hot water heating and space heating appliances, with the latter relevant to the western region due to cooler weather conditions compared to other parts of the network.[4] APT Allgas estimated that the overall impact of appliance upgrades on residential consumption is a reduction of 5128 GJ per year. It is stated that this is equivalent to replacing 4000 storage hot water heaters with instantaneous water heaters per annum, with each replacement reducing annual gas consumption from 10 GJ to 8.7 GJ (or by 13 per cent).[5]

APT Allgas provided a detailed demand forecast modelling spreadsheet to show how the assumptions and inputs have been incorporated into the forecasting model. The actual and forecast customer numbers and consumption by tariff categories are presented in table 9.1.

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1 APT Allgas, *Access arrangement submission, attachment 3.1 Load forecast*, September 2010, pp. 7–8.
2 APT Allgas, *Access arrangement submission*, September 2010, pp. 24–29.
3 APT Allgas, *Access arrangement submission, attachment 3.1 Load forecast*, September 2010, pp. 11–13.
4 APT Allgas, *Access arrangement submission, attachment 3.1 Load forecast*, September 2010, pp. 14–19 and 26.
5 APT Allgas, *Access arrangement submission, attachment 3.1 Load forecast*, September 2010, p. 25.

Table 9.1: APT Allgas historical and forecast demand, 2006–07 to 2015–16

	2006–07 (Actual)	2007–08 (Actual)	2008–09 (Actual)	2009–10 (Estimate)	2010–11 (Forecast)	2011–12 (Forecast)	2012–13 (Forecast)	2013–14 (Forecast)	2014–15 (Forecast)	2015–16 (Forecast)
Tariff V										
Numbers of residential customer	68 076	71 242	74 624	76 983	79 420	82 153	84 953	87 824	90 766	93 801
Residential customer consumption - TJ	801	766	805	785	781	789	799	809	831	854
Numbers of small business customer	5580	5280	4860	4739	4870	5016	5166	5319	5477	5640
Small business customer consumption - TJ	2094	2154	2107	2015	2063	2119	2185	2253	2323	2395
Tariff D										
Demand class customer numbers	108	109	114	102	101	102	103	104	105	106
Demand customer consumption (TJ)	7208	7679	7565	7666	6955	6970	6985	7000	7015	7030
Maximum daily quantity (MDQ) - GJ/Day	34 473	35 087	37 282	37 319	34 847	34 947	35 047	35 147	35 247	35 347
Maximum hourly quantity (MHQ) - GJ/Hour	2592	2606	2988	2846	2703	2713	2723	2733	2743	2753

Source: APT Allgas, *Access arrangement submission, attachment 3.1, Load forecast,* table 2-6, table 3-2, table3-4 and appendix C.

9.4 Consultant review

The AER engaged ACIL Tasman Pty Ltd (ACIL Tasman), demand forecasting consultants, to assess the reasonableness of APT Allgas's proposed demand forecasts (the ACIL Tasman report)[6]. This included an assessment of the actual demand compared to forecasts in the earlier access arrangement period.

ACIL Tasman considered the overall approach to forecasting the various elements of gas demand was systematic and supported by data of generally good quality. ACIL Tasman considered that the resultant demand forecasts were for the most part reasonable.[7]

In its report, ACIL Tasman highlighted two areas where the demand forecasts could be improved. In particular, ACIL Tasman recommended that:[8]

- given the strong downward trend in volume business customer numbers over the period 2006–07 to 2009–10, the proposed forecast over the access arrangement period should be reduced to the level equal to the average over the period 2006 to 2010 (5094 customers).

- where appropriate the methodology for forecasting average residential consumption in the western region should be adjusted, including an assessment of the potential impact of weather on observed reductions in residential demand in the western region.

9.5 AER's consideration

9.5.1 Introduction

The AER considers that for the most part, the forecast methodology and the resultant demand forecasts proposed by APT Allgas are reasonable. The AER accepts that APT Allgas's residential customer numbers, MDQ and MHQ forecasts are reasonable. However, the AER does not accept the proposed residential consumption forecast in the western region and the volume business customer number forecast. The amendments required for these aspects of the forecast to be accepted as the best possible forecasts in the circumstances are discussed in sections 9.5.3 and 9.5.5.

9.5.2 Residential customer numbers

The AER considers APT Allgas's forecasting methodology for residential customer numbers based on the HIA long term dwelling starts forecast is reasonable given the historical data shows reasonable correlation between numbers of dwelling starts and residential customer connections.[9]

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6 ACIL Tasman, *Review of demand forecasts for APT Allgas for the access arrangement period commencing 1 July 2011*, December 2010.
7 ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010 p. 35.
8 ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010 pp. 35–36. .
9 APT Allgas, *Access arrangement submission, attachment 3.1, Load forecast*, September 2010, p. 13

During the review, some data issues have been identified and subsequently corrected by APT Allgas for the forecast numbers of residential customers.[10] The updated forecast is set out in table 9.2.[11]

Table 9.2: APT Allgas updated residential customer numbers forecast

	2011-12	2012-13	2013-14	2014-15	2015-16
APT Allgas updated forecast	82 355	85 261	88 240	91 292	94 439
APT Allgas original forecast	82 153	84 953	87 824	90 766	93 801

Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 - Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010.

The AER reviewed APT Allgas's demand forecast modelling spreadsheet, and is satisfied that the forecasting methodology has been correctly applied in the calculation of the forecasts.

The AER found that the forecast growth in customer numbers is broadly in line with the dwelling growth projection released by the Queensland Office of Economic and Statistical Research (OESR),[12] and that the forecast is also in line with the historical trend.[13] Given the link between numbers of dwellings and residential customer numbers, the AER considers APT Allgas's residential customer numbers forecast is reasonable.

9.5.3 Volume business customer numbers forecast

Based on ACIL Tasman's regression analysis, the AER observes that APT Allgas's volume business customer numbers forecast show a reverse of the historical trend over the last four years as presented in figure 9.1.[14]

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10 APT Allgas, Email to the AER, *RE: AER.APT.12 plus ACIL Tasman question*, 18 November 2010.

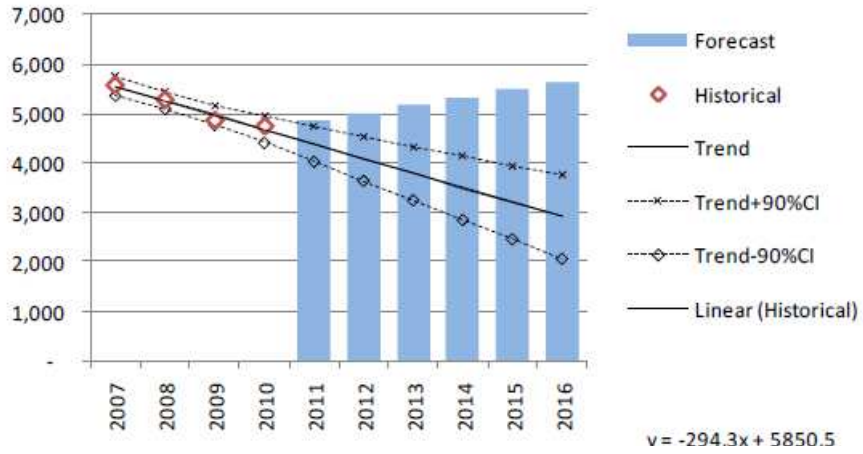
11 APT Allgas, Email to the AER, *RE: AER.APT.12 plus ACIL Tasman question*, 18 November 2010. APT Allgas, Email to the AER, *APT Allgas Load Forecasts*, 30 November 2010.

12 OESR, *Household projections by household type by region, 2006 to 2031*, 2008, viewed at http://www.oesr.qld.gov.au/products/tables/household-proj-household-type-region/index.php *Household and dwelling projections Queensland local government areas*, 2008, viewed at http://www.oesr.qld.gov.au/products/publications/household-dwel-proj-qld-lga/index.php

13 See, ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, pp. 19–20.

14 ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, pp. 20–21.

Figure 9.1: APT Allgas historical and forecast volume business customer numbers



Source: ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, p 20.

In response to a question from the AER regarding the significant increase in forecast numbers of volume business customers, APT Allgas responded that:

> While APT Allgas remains of the view that it is reasonable to forecast a per capita proportion of Volume business customers (for example, hairdressers, dry cleaners, food outlets, etc), it is possible that the proportion of Volume business customers may not be completely correlated to residential growth (for example, plastics fabricators, panel beaters, etc). Considering in conjunction with the observed reduction in Volume business customers, it would be reasonable to reduce the number of new business customers forecast to connect to the network over the forecast period.

The AER accepts that the arguments put forward by APT Allgas have some merit. However, in the absence of detailed supporting information, the AER considers it is reasonable to take a cautious approach. Based on ACIL Tasman's advice,[15] the AER adjusted the new volume business customer connection forecast to reflect a steady increase in total numbers of customers to the level equal to the average over the period 2006 to 2010 (5094 customers) for the access arrangement period. The AER's draft decision on forecast volume business customer numbers is set out in table 9.3.

Table 9.3: Volume business customer numbers forecast

	2011–12	2012–13	2013–14	2014–15	2015–16
Volume business customer numbers – APT Allgas	5026	5182	5341	5505	5674
Volume business customer numbers – AER	4857	4917	4976	5035	5094

Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 - Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010.

[15] ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, p. 35.

9.5.4 Demand customer (Tariff D) numbers forecast

The AER observes that APT Allgas forecast a net gain of one additional Tariff D customer per year for the access arrangement period, which is in line with the historical trend.[16]

The AER acknowledges that large new demand customers will typically approach gas network providers at the planning stage of a project to ascertain the cost and the availability of gas at a particular site. The AER understands that APT Allgas has not currently received any inquiries for large load connections for the access arrangement period.[17] In the absence of such evidence, the AER accepts that APT Allgas's demand customer numbers forecast, developed based on the historical trend, is reasonable.

9.5.5 Residential customer consumption forecast

Forecasts of average or per customer consumption, combined with customer numbers, are the basis on which residential gas consumption forecasts are calculated. The AER observes that total residential consumption is forecast to grow on average by 1.4 per cent per year over the period 2010–11 to 2015–16. The forecast growth is predominantly driven by 3.5 per cent annual growth in customer numbers, partially balanced out by a 2 per cent decline in average consumption per year.[18]

As noted in section 9.3, the decline in average consumption for the central and the southern regions is linked to the expected saving in consumption from replacement of storage gas hot water heaters with more energy efficient systems. The AER accepts that the adjustments are reasonable for the following reasons:

- the assumed annual replacement rate of 4000 storage hot water heaters with more energy efficient instantaneous systems appears reasonable based on analysis of household hot water heating energy use data released by the ABS[19], and Equipment Energy Efficiency Committee analysis on the average life of gas hot water heaters[20]

- the assumed energy efficiency gain of 13 per cent from replacement of a storage hot water heater with an instantaneous gas hot water heater is broadly in line with the expected improvement in energy efficiency star rating of appliances from 3.5 to 5 stars.[21] This assumption appears reasonable given the observed improvements in star ratings for water heaters certified in recent years compared to systems

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16 ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, pp. 29–31.

17 APT Allgas, Email to the AER, *RE: AER.APT.12 plus ACIL Tasman questions*, 18 November 2010.

18 APT Allgas, *Access arrangement submission, attachment 3.1 Load forecast*, September 2010, pp. 22 and 33.

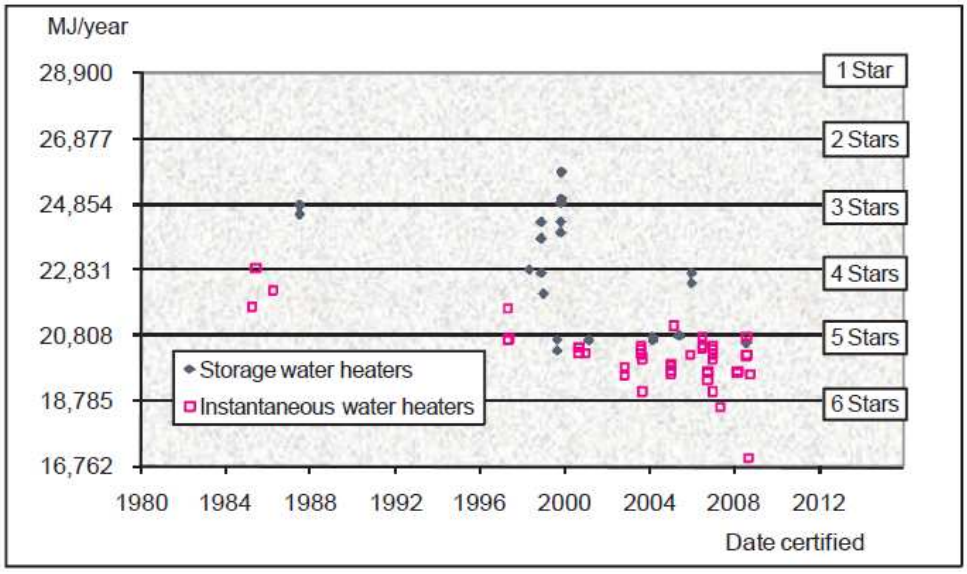
19 ABS, catalogue number 4602.3 - *Queensland Water and Energy Use and Conservation*, October 2009.

20 Equipment Energy Efficiency Committee, *Regulatory impact statement – Proposal to introduce a Minimum Energy Performance Standard for Gas Water Heaters*, October 2009, p. 17.

21 Calculated based on the methodology outlined in Equipment Energy Efficiency Committee, *Regulatory impact statement – Proposal to introduce a Minimum Energy Performance Standard for Gas Water Heaters*, October 2009, pp. 6–7.

certified in 1990s and early 2000s as illustrated in figure 9.2.[22] In coming to this view, the AER has also considered the expected energy saving from hot water conservation, and the replacement of conventional hot water heating systems with solar boosted systems.

Figure 9.2: Energy efficiency star ratings for a selected list of the gas hot water heaters by type and date of certification



Source: Equipment Energy Efficiency Committee, *Regulatory impact statement – Proposal to introduce a Minimum Energy Performance Standard for Gas Water Heaters*, October 2009, p. 6.

While the AER accepts APT Allgas's consumption forecasts for the central and southern regions, the AER does not accept the forecast average consumption in the western region. Based on a projection of the recent historical trend, APT Allgas forecast residential customer average consumption in the western region (Toowoomba and Oakey) to decline over the access arrangement period to a level similar to the central and southern regions as presented in figure 9.3.[23] The AER considers the magnitude of the decline projected by APT Allgas is overstated, as the reduction of market share and appliance efficiency gains are unlikely to completely eliminate space heating loads in the region.

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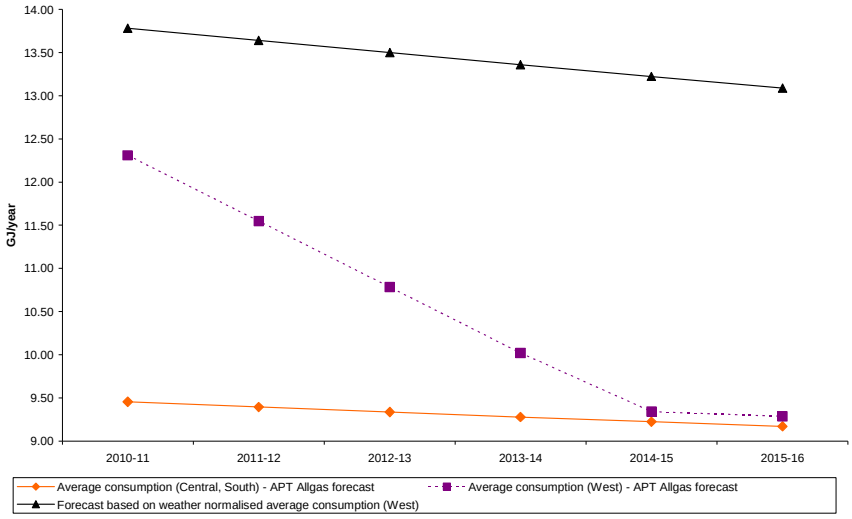
22 Higher star rating indicates higher energy efficiency. Equipment Energy Efficiency Committee, *Regulatory impact statement – Proposal to introduce a Minimum Energy Performance Standard for Gas Water Heaters*, October 2009, p. 6.

23 APT Allgas, Email to the AER, *RE: AER.APT.12 plus ACIL Tasman questions, attachment, 20101117 Response to ACIL Tasman load forecast queries.pdf*, 18 November 2010.

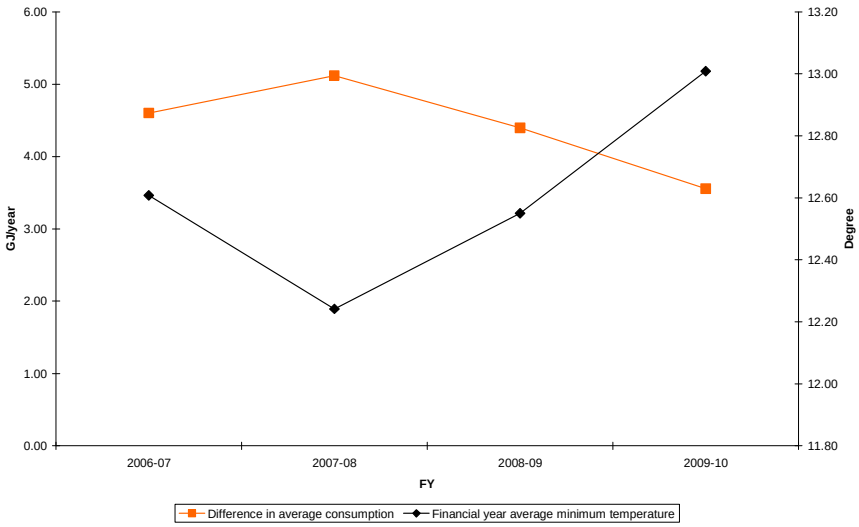
Figure 9.3: Average residential consumption by region – GJ/year



Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010 (confidential).

APT Allgas based its forecast on raw consumption data.[24] The AER expects weather conditions to have a material impact on gas consumption in the western region. Table 9.4 and figure 9.4 demonstrate the strong negative correlation (-0.98) between average annual minimum temperature and the difference between average consumption in the western and other regions of APT Allgas's network.

Figure 9.4: Average annual minimum temperature and difference in average consumption per residential customer between western and other regions



Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010 (confidential); and Bureau of Meteorology, monthly minimum temperature data viewed at http://www.bom.gov.au/climate/data/.

[24] APT Allgas, Email to the AER, *RE: AER.APT.12 plus ACIL Tasman questions, attachment 20101117 Response to ACIL Tasman load forecast queries.pdf*, 18 November 2010.

Table 9.4: Average annual minimum temperature and average consumption per residential customer by region

	Average consumption (Western region) – GJ/year	Average consumption (Central, Southern regions) – GJ/year	Difference in average consumption – GJ/year	Average minimum temperature - Degrees
2006–07	15.44	10.84	4.60	12.61
2007–08	14.87	9.75	5.12	12.24
2008–09	14.33	9.93	4.40	12.55
2009–10	13.07	9.52	3.55	13.01

Source APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010 (confidential); and Bureau of Meteorology, monthly minimum temperature data viewed at http://www.bom.gov.au/climate/data/.

Based on its analysis, the AER has adjusted the consumption forecast for the western region to the level presented in table 9.5, derived using weather normalised historical consumption data.

Table 9.5: Residential consumption forecasts – western region

	2011–12	2012–13	2013–14	2014–15	2015–16
Total consumption (Western) – TJ – APT Allgas proposal	173.4	164.4	155.1	146.8	148.2
Weather normalised total consumption (Western) – TJ – AER draft decision	204.9	205.8	206.8	207.8	208.9

Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010 (confidential).
Weather normalised annual average consumption estimated by the AER.
Weather normalised total consumption calculated by the AER using APT Allgas' demand forecast model, *20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*.

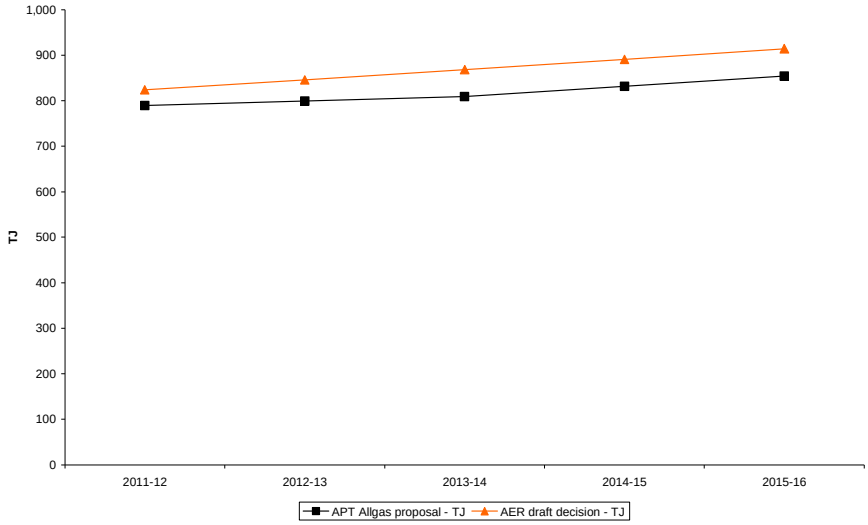
The AER considers that the proposed total residential consumption should be revised upward to the level set out in table 9.6 to account for weather sensitive space heating demand in the western region. The AER considers the revised forecast derived on this basis represents the best forecast possible in the circumstances. Figure 9.5 compares the consumption forecast for residential customers as proposed by APT Allgas and approved by the AER.

Table 9.6: Residential consumption forecasts

	2011-12	2012-13	2013-14	2014-15	2015-16
APT Allgas proposal - TJ	789	799	809	831	854
AER draft decision - TJ	824	846	868	891	914

Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010 (confidential).

Figure 9.5 APT Allgas proposal and AER draft decision residential consumption forecasts

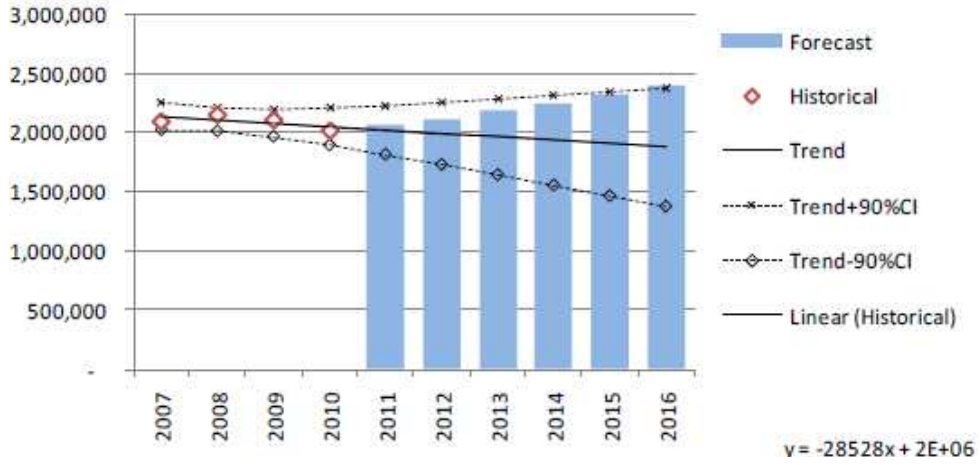


Source: APT Allgas, Email to the AER, *APT Allgas Load Forecasts, attachment, 20101130 -Demand Summary - CONFIDENTIAL (AERv3).xls*, 30 November 2010 (confidential).

9.5.6 Volume business customer consumption forecast

Based on ACIL Tasman's regression analysis, the AER observes that the proposed volume business customer consumption forecast as presented in figure 9.6 lies above the historical trend.

Figure 9.6 Actual and forecast volume business gas consumption – GJ



Source: ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, p. 28.

In light of potential improvements in the Queensland economy as evident from the GSP forecasts from a number of sources as presented in table 9.7, the AER accepts that a corresponding increase in business activities and therefore volume business gas consumption does not appear unreasonable.

Table 9.7: Queensland GSP forecasts from various sources

	BIS Shrapnel	KPMG Econtech	Access Economics	ABS
Average growth 2005–06 to 2009–10				3.1%
Average growth 2010–11 to 2015–16	4.1%	4.3%	4.4%	

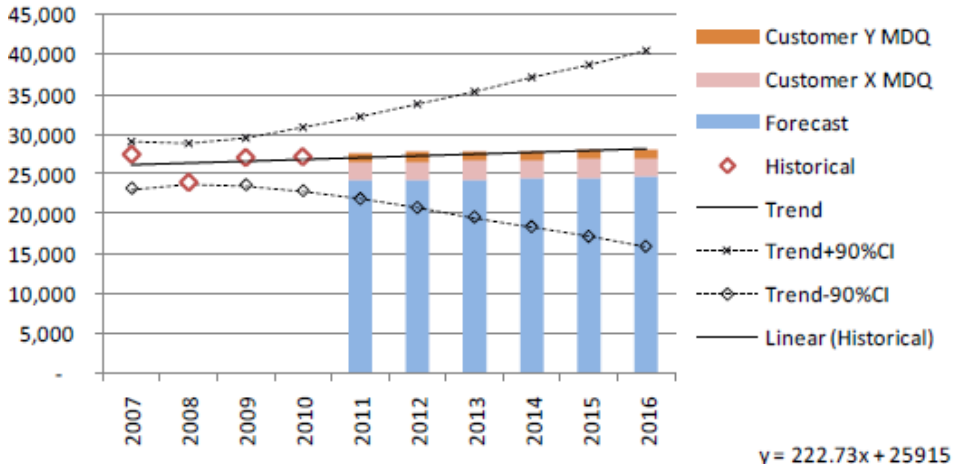
Source: ABS, cat 5220.0 *Australian National Accounts: State Accounts, Queensland; Gross state product: Chain volume measures*.
BIS Shrapnel, *Real Cost Escalation Forecasts to 2015/16 – Queensland and South Australia*, August 2010, p. 12.
KPMG Econtech, *ANSIO report*, December 2010, p. 108.
Access Economics, *Forecast growth in labour costs: Queensland and South Australia*, December 2010, p. 10.

9.5.7 Demand customer MDQ and MHQ forecast

Demand customers are billed based on their demand capacity measured by MHQ and MDQ instead of actual consumption. The AER observes that APT Allgas's MHQ forecast is statistically consistent with the historical trend,[25] while the MDQ forecast as presented in figure 9.7 shows a step decline in 2010–11, reflecting the loss of two large customers.

[25] ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, pp. 34–35.

Figure 9.7: Demand customer MDQ forecast – GJ



Source: ACIL Tasman, *Review of demand forecasts for APT Allgas*, December 2010, p. 34.

Based on ACIL Tasman's advice, and given there is no expected increase in large demand customer numbers as noted in section 9.5.4, the AER considers APT Allgas's MDQ and MHQ forecasts are reasonable and represents the best forecasts possible in the circumstances.

9.5.8 Minimum, maximum and average demand

Rule 72(1)(a)(iii) of the NGR requires that the access arrangement information for a distribution pipeline must include minimum, maximum and average demand for the earlier access arrangement. The AER considers the data provided by APT Allgas in its access arrangement information, and reproduced in table 9.8 below, meets the requirement of r. 72(1)(a)(iii) of the NGR.[26]

Table 9.8: Minimum, maximum and average demand 2005–06 to 2010–11 (TJ per day)

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11
	Actual	Actual	Actual	Actual	Actual	Estimate
Minimum demand – TJ/day	11.83	12.28	12.77	14.38	13.24	12.14
Maximum demand – TJ/day	36.52	42.29	42.15	41.72	40.15	38.52
Average demand – TJ/day	27.48	29.60	30.22	29.87	30.12	27.99

Source: APT Allgas, *Access arrangement information*, September 2010, p. 5.

9.5.9 Forecast pipeline capacity and utilisation

Rule 72(1)(a)(iii) 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 considers the data

[26] APT Allgas, *Access arrangement information*, September 2010, p. 5.

provided by APT Allgas in its access arrangement information, reproduced in table 9.9 below, meets the requirement of r. 72(1)(a)(iii) of the NGR.

Table 9.9: Forecast pipeline capacity and utilisation

	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
Pipeline capacity (TJ per day)	52.44	53.86	54.40	54.94	59.06	59.65
Utilisation of pipeline capacity (%)	73.5%	71.8%	71.8%	71.7%	67.3%	67.1%

Source: APT Allgas, *Access arrangement information*, September 2010, p. 12.

9.6 Conclusion

Based on ACIL Tasman's advice and its own assessment, the AER accepts that APT Allgas's demand forecasts for residential customers in the central and southern regions and Tariff D customers are reasonable and represent the best forecasts possible in the circumstances. For the reasons discussed in sections 9.5.3 and 9.5.5, the AER adjusted the small business customer numbers forecast, and residential consumption forecast for the western region to the levels set out in tables 9.3 and 9.5 respectively.

The AER does not approve APT Allgas's proposed demand forecasts as they do not meet the requirements of r. 74 of the NGR.

Overall, the AER's amendments to the proposed demand forecast will lower the X-factor by 0.14 per cent on average over the access arrangement period. In other words, the maximum allowed increase in weighted average prices for all customers is reduced by approximately 0.14 per cent on average over the access arrangement period.

9.7 Required amendments

Before the proposed access arrangement submission can be accepted, APT Allgas must make the following amendments

Amendment 9.1: amend the access arrangement information to delete Table 4.1 and replace it with the following table:

Table 9.10: AER draft decision on APT Allgas's demand forecasts

	2011–12	2012–13	2013–14	2014–15	2015–16
Volume class customer numbers	87 213	90 178	93 215	96 327	99 533
Demand class customer numbers	102	103	104	105	106
Volume class consumption – TJ	2945	3036	3129	3225	3323
Demand class consumption – TJ	6970	6985	7000	7015	7030

10 Reference tariffs

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 done 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.

APT Allgas has proposed the same tariffs it offered in the earlier access arrangement, including a volume tariff, 10 demand tariffs across four regions, and tariffs for three ancillary services. APT Allgas also provided a range of information in support of its proposed tariffs in order to meet NGR requirements about the formulation of reference tariffs.

The AER considers that the tariffs proposed by APT Allgas meet many requirements of the NGR. However, the AER considers that APT Allgas has not adequately supported its proposal to categorise volume and demand customers based on their maximum demand. The AER also considers that APT Allgas did not adequately separate the allocation of revenue between reference services and other services. In addition, APT Allgas did not include ancillary services in its demonstration of transaction costs and customer responses, and long run marginal costs. Finally, the AER considers that APT Allgas did not provide sufficient information to support the prudent discounts it proposed for four customers.

In revising its reference tariffs to address matters in this chapter, APT Allgas is required to incorporate the various amendments required by the AER in other chapters of this draft decision.

10.1 Introduction

This chapter sets out the AER's consideration of APT Allgas's tariff proposals about the structure of tariffs and allocation of revenue, rather than the level of tariffs against the requirements of the NGR. APT Allgas's access arrangement proposal 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-reflectiveness of tariffs and charging parameters.

10.2 Regulatory requirements

With respect to reference tariffs, the NGR requires APT Allgas to:

- specify the tariffs for each reference service (r. 48(1)(d)(i) and (ii))
- demonstrate that total revenue is allocated between reference and other services on the basis of costs allocated according to certain principles (r. 93(1) and (2))

- divide reference service customers into tariff classes (r. 94(1)) that are economically efficient and avoid unnecessary transaction costs (r. 94(2))

- 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 revenue expected from each tariff class is within certain lower and upper thresholds (r. 94(3))

- demonstrate that each tariff and its charging parameters must take into account long run marginal costs, transaction costs and customer responses to price signals (r. 94(4))

- demonstrate that prudent discounts offered to customers are necessary for competition or efficiency reasons and that this will likely lead to lower tariffs for other customers (r. 96).

10.3 Access arrangement proposal

APT Allgas's tariff proposals are described in table 10.1. In summary, APT Allgas proposed a volume tariff, 10 demand tariffs across four regions, and three ancillary services. The tariff classes proposed APT Allgas directly reflect the reference services it proposed, as discussed in chapter 2 of this draft decision.

APT Allgas's general approach to tariffs in its access arrangement proposal is unchanged from the earlier access arrangement. Specifically, APT Allgas retained the same tariff classes, number of tariffs in each tariff class, and tariff parameters for each tariff. The thresholds at which different consumption charges apply also remain unchanged.

Table 10.1: APT Allgas's proposed tariff classes, tariffs and tariff parameters

Tariff classes	Tariffs	Tariff parameters
Volume services	Volume tariff	Fixed standing charge Stepped variable consumption charge
Demand services	Demand tariffs for: Brisbane – 3 zones Toowoomba – 2 zones Oakey – 2 zones South Coast – 3 zones	Fixed standing charge (based on customer's demand) Stepped variable demand charge
Ancillary services	Inlet disconnection Inlet reconnection Special meter read	Fixed charge

Source: APT Allgas, *Access arrangement submission*, September 2010, pp. 146–147.

While the tariff structures proposed by APT Allgas have not changed, the relative magnitude of tariff parameters has changed from the earlier access arrangement period. Specifically, APT Allgas has slightly re-balanced charges, with more revenue to be recovered by fixed base charges and low levels of consumption and demand. In addition, APT Allgas proposed significantly lower ancillary services tariffs than those in the earlier access arrangement. Also, APT Allgas proposed categorising customers as volume or demand customers based on their consumption and maximum demand levels, as opposed to just their consumption levels in the earlier access arrangement period.[1]

APT Allgas proposed to base its reference service tariffs on the cost allocation method used in the earlier access arrangement period, but the access arrangement proposal omitted ancillary services and capital contributions.[2] APT Allgas's proposal did not include any information regarding the relationship between costs and tariffs.

Table 10.2: APT Allgas expected revenue compared to avoidable and stand alone costs for volume and demand tariff classes, 2011–12 ($m, nominal)

	Avoidable cost	Expected revenue	Stand alone cost
Demand class	0.3	17.3	23.6
Volume class	35.1	41.4	58.4

Source: APT Allgas, *Access arrangement submission*, September 2010, p. 150.

10.4 Submissions

A submission was received from AGL.

AGL noted APT Allgas's proposal to categorise customers as volume or demand customers based on their consumption and demand levels, instead of just their consumption levels, as in the earlier access arrangement period. AGL cited concerns with the new definitions of volume and demand customers proposed by APT Allgas and stated they were not in the interests of network users and end-use consumers.[3]

AGL also stated it was unclear whether a special meter read fee was to be applied per site visit or applied per meter read at the premises and requested that APT Allgas specify the circumstances under which the fee will be applied.[4]

10.5 AER's considerations

The following outlines the AER's consideration of APT Allgas's proposal for its compliance with the NGR. The AER has identified those elements of APT Allgas's proposal that meet the NGR requirements and those elements that require amendment in order to sufficiently demonstrate that certain tariff characteristics comply with the NGR. In addition, the AER has identified that tariffs need to be recalculated to reflect the adjustments made to revenue and demand, as discussed in chapters 8 and 9.

1 APT Allgas, *Access arrangement submission*, September 2010, table 9-2, p. 146.
2 APT Allgas, *Access arrangement submission*, September 2010, pp. 147–148.
3 AGL, *APT Allgas's access arrangement submission*, November 2010, p. 2.
4 AGL, *APT Allgas's access arrangement submission*, November 2010, p. 3.

10.5.1 Tariff classes and tariffs

APT Allgas has proposed to divide customers for its reference services into the same reference tariff classes used in the earlier access arrangement period. The AER considers that this is in accordance with the requirements of r. 48(1)(d)(i) and r. 94(1) of the NGR to specify tariff classes.

APT Allgas considered a range of factors that the AER considers relevant to the economic efficiency of providing reference services and the associated transaction costs, including for example:

- bases for grouping customers, such as consumption patterns and quantities, connection and meter types, and location
- customers' impact on pipeline costs
- customers' response to price signals.[5] [6]

It is clear from APT Allgas's access arrangement information and access arrangement submission that tariff classes (and tariffs) were developed with some regard to economic efficiency and transaction costs.

However, the AER notes that APT Allgas did not provide the reasons for its proposal to categorise customers as volume or demand customers based on their demand levels in addition to their consumption levels as in the earlier access arrangement. As a result, it is unclear whether APT Allgas had regard to economic efficiency and transaction costs in proposing the new basis for categorising volume and demand customers. On this basis the AER considers that the tariff classes proposed by APT Allgas do not meet the requirements of r. 94(2) of the NGR.

10.5.2 Allocation of total revenue and costs to tariff classes

The NGR includes requirements at two levels of revenue and cost allocation – the first between reference services and non-reference services[7] and the second between reference services.[8]

10.5.2.1 Allocation of revenue and costs between reference services and other services

APT Allgas stated that its cost allocation approach ensures that the revenue derived from the application of the reference tariffs is equal to the total revenue.[9] However, in a confidential attachment, APT Allgas indicated that assets associated with negotiated services are included in APT Allgas's regulated asset base and that the revenue received for the negotiated services is included in APT Allgas's total revenue.[10] APT Allgas did not demonstrate how much revenue is expected to be recovered from negotiated services and how it relates to the costs of providing the negotiated services, as required by r. 93(1) of the NGR. In addition, while APT Allgas described cost

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5 APT Allgas, *Access arrangement submission*, September 2010, pp. 144–147.
6 APT Allgas, *Access arrangement information*, September 2010, pp. 23–24.
7 NGR, r. 93.
8 NGR, r. 72(1)(j)(i).
9 APT Allgas, *Access arrangement submission*, September 2010, p. 148.
10 APT Allgas, *Access arrangement submission*, September 2010, confidential attachment 9.1, p. 6.

allocation between reference services (as discussed in section 10.5.2.2), it did not describe cost allocation between reference and other services (including negotiated services), as required by r. 93(2) of the NGR. For these reasons, the AER considers that APT Allgas has not adequately addressed NGR requirements on how total revenue is allocated between reference and other services.

10.5.2.2 Allocation of revenue and costs between reference services

APT Allgas proposed to base its reference service tariffs on the cost allocation method used in the earlier access arrangement period, together with uniform escalation of tariffs for all tariff classes.[11] In its proposal, APT Allgas stated that it took this approach because its network configuration and customer profile was largely the same as when the cost allocation process was undertaken for the earlier access arrangement.[12] The AER considers that APT Allgas's description of the cost allocation process used to calculate tariffs is adequate, but that it omits two elements – ancillary services and capital contributions:

- ancillary services are reference services and therefore must be included in APT Allgas's response to r. 72(1)(j)(i) of the NGR

- capital contributions are deducted from APT Allgas's total revenue requirement (along with ancillary services revenue) in order to determine revenue to be recovered from volume and demand tariffs.[13] As a result, capital contributions need to be addressed to provide an accurate account of the basis of reference tariffs as required by r. 72(1)(j)(i).

APT Allgas did not include any information that demonstrated the relationship between costs and tariffs, as required under r. 72(1)(j)(i) of the NGR. In its revised access arrangement proposal, APT Allgas should include ancillary services and capital contributions. APT Allgas should also address inconsistent information about tariffs and costs for demand customers that it provided to show that tariff revenue is below stand alone costs. Specifically, APT Allgas stated that demand customers' tariffs were based on group stand alone costs.[14] However, APT Allgas's estimate of group stand alone costs for demand customers ($24 million) is significantly higher than the tariff revenue APT Allgas expects from demand customers ($17 million).[15] The AER considers that APT Allgas could demonstrate the relationship between costs and tariffs by quantifying the step-by-step cost allocation process for calculating tariffs that it provided in its access arrangement submission (amended to include ancillary services and capital contributions). The AER expects this demonstration will explain why ancillary service tariffs proposed by APT Allgas for 2010–11 are to fall so much relative to the earlier access arrangement period.

APT Allgas included its discussion of the basis for tariffs, including cost allocation, in its access arrangement submission. Rule 72(1)(j) of the NGR requires that this material be included in APT Allgas's access arrangement information. The AER

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11 APT Allgas, *Access arrangement submission*, September 2010, pp. 147–148.
12 APT Allgas, *Access arrangement submission*, September 2010, p. 148.
13 APT Allgas, *Access arrangement submission*, September 2010, p. 148.
14 APT Allgas, *Access arrangement submission*, September 2010, p. 147.
15 APT Allgas, *Access arrangement submission*, September 2010, p. 150.

considers that the access arrangement information will not be acceptable unless it includes all discussion of the basis for tariffs required under r. 72 of the NGR, including cost allocation and the demonstration of the relationship between costs and tariffs.

10.5.3 Tariff class revenues and parameters

Rule 94 of the NGR imposes limits on the revenue that can be recovered for each reference tariff class and includes requirements related to the nature of tariffs and tariff parameters.

10.5.3.1 Tariff class revenue limits

For each tariff class, r. 94(3) of the NGR requires that tariff revenue lie between the stand alone cost of supplying customers and the avoidable cost of not supplying them. The AER has reviewed APT Allgas's definitions of avoidable and stand alone costs for volume and demand tariff classes and considers they are acceptable for assessing APT Allgas's compliance with the NGR for these tariff classes. APT Allgas's estimates of avoidable and stand alone costs relative to expected revenue for volume and demand tariff classes are shown in table 10.2.

Compared to the earlier access arrangement, the tariffs APT Allgas proposed included slightly re-balanced charges, with a greater share of revenue to be recovered from fixed base charges and low levels of consumption and demand. This re-balancing is permissible under the revenue limits imposed on tariff classes under the NGR. As shown in table 10.2, the revenue APT Allgas expects to recover from volume and demand customers lies well within the broad range of avoidable and stand alone costs for each tariff class. However, as discussed in section 10.5.2.2, APT Allgas provided inconsistent information about the relationship between expected revenue and stand alone costs for demand customers. This inconsistency raises doubt about the accuracy of the estimates presented in table 10.2. APT Allgas is required to address this inconsistency in its revised access arrangement submission in order for the AER to assess compliance with r. 94(3).

10.5.3.2 Tariffs and charging parameters

The NGR requires that each tariff and its charging parameters must take into account to long run marginal costs, and must be determined having regard to transaction costs and customer responses to price signals.[16] As discussed in section 10.5.1, the AER considers that APT Allgas has not adequately addressed requirements on transaction costs in proposing to categorise customers as volume or demand customers based on their maximum demand levels. Aside from this issue, the AER considers that APT Allgas's formulation of tariff classes[17] shows adequate consideration of transaction costs and customer responses for volume and demand services but not for ancillary services. This is because ancillary services were not included in

[16] NGR, r. 94(4).
[17] See section 10.5.1.

APT Allgas's discussion of transaction costs[18] and customer responses were not included in the discussion of ancillary services.[19]

The AER also considers that APT Allgas appropriately accounted for long run marginal costs in constructing volume tariffs, demand tariffs and volume tariff parameters, based on its review of section 9.5 of the access arrangement submission, which includes LRMC estimates for residential and demand customers. However, APT Allgas did not address how tariffs for ancillary services and charging parameters for demand tariffs take account of long run marginal costs. APT Allgas is therefore required to address these omissions in its revised access arrangement proposal.

10.5.4 Prudent discounts

APT Allgas proposed prudent discounts for four of its demand customers.[20] The Queensland Competition Authority approved prudent discounts for the same four customers in its 2001 and 2006 decisions on APT Allgas's access arrangements.[21] The AER reviewed the confidential information provided by APT Allgas against the requirements for approving prudent discounts under r. 96 of the NGR. Based on this review, the AER is satisfied that:

- each discount is in response to the potential bypass of APT Allgas's network in favour of another pipeline service provider or energy source (r. 96(2)(i))

- each discount is likely to lead to reference tariffs being lower than otherwise because the revenue from the discounted tariffs exceeds the variable costs of servicing the customer. As a result, each customer will contribute to APT Allgas's fixed costs (r. 96(2)(b)).

10.5.5 Other considerations

The AER notes that APT Allgas uses a 'seasonality factor' to calculate maximum daily quantity (MDQ) for demand customers without interval meters.[22] APT Allgas proposed to increase this factor from 1.1 in the earlier access arrangement to 1.3 in the access arrangement proposal. APT Allgas indicated that very few customers' MDQ will be calculated using a seasonality factor (around one each year).[23] APT Allgas indicated that the factor was increased from 1.1 to 1.3 to better reflect the overall network load factor.[24] Based on the information provided by APT Allgas, the AER is satisfied that the proposed adjustment to the seasonality factor is appropriate.

10.6 Conclusion

The AER considers that the tariffs proposed by APT Allgas meet many of the requirements of the NGR, including r. 48(1)(d)(i), r. 94(1), r. 96(2)(i) and r. 96(2)(b).

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18 APT Allgas, *Access arrangement submission*, September 2010, p. 146.
19 APT Allgas, *Access arrangement submission*, September 2010, p. 152.
20 APT Allgas, *Access arrangement submission*, September 2010, Attachment 9.1, Prudent discounts (confidential).
21 QCA, *Final Decision, Revised Access Arrangement for Gas Distribution Networks: Allgas Energy*, May 2006, pp. 114–115.
22 APT Allgas, *Access arrangement proposal*, Appendix B, see footnotes to tables 2 – 5.
23 APT Allgas, *Email response to AER question AER.APT.03*, 29 October 2010.
24 APT Allgas, *Email response to AER question AER.APT.03*, 29 October 2010.

However, the AER proposes not to approve the following aspects of APT Allgas's access arrangement proposal, as they do not comply with the NGR and requires APT Allgas to make the amendments set out in section 10.7.

- all reference tariffs—all reference tariffs require amendment to reflect amendments to total revenue and demand set out in chapters 8 and 9
- definitions of demand and volume customers based on consumption and demand—APT Allgas's access arrangement proposal does not comply with r. 94(2) of the NGR
- allocation of revenues and costs to reference and other services—APT Allgas's access arrangement does not comply with r. 93(1) and 93(2) of the NGR
- allocation of revenue and costs between tariff classes—APT Allgas's access arrangement proposal does not comply with r. 72(1)(j)(i) of the NGR
- other factors influencing tariffs and charging parameters—APT Allgas's access arrangement proposal does not comply with r. 94(4) of the NGR.

10.7 Required amendments

Before the access arrangement proposal can be approved, APT Allgas must make the following amendments.

Amendment 10.1: amend the access arrangement information to:

- include all discussion of the basis for tariffs required under r. 72 of the NGR
- include discussion of ancillary services and capital contributions in the cost allocation description
- demonstrate the relationship between costs and tariffs, including for ancillary services, and to address the treatment of capital contributions.

Amendment 10.2: amend the access arrangement submission to

- demonstrate that APT Allgas has had regard to economic efficiency and transaction costs in proposing the new basis for categorising volume and demand customers
- demonstrate that revenue is allocated between reference and other services in the ratio in which costs are allocated between reference and other services
- demonstrate that costs are allocated between reference and other services according to r. 93(2) of the NGR
- clarify the relationship between expected revenue and stand alone costs for demand customers

- include consideration of transaction costs and customer responses for ancillary services

- address how tariffs and charging parameters for demand tariffs take account of long run marginal costs.

Amendment 10.3: amend the access arrangement proposal to:

- exclude all references to MDQ as a basis for categorising customers as volume or demand customers.

11 Tariff variation mechanism

An access arrangement is required to set out how tariffs may be varied during the access arrangement period. APT Allgas has proposed a tariff variation mechanism that allows tariffs to be adjusted by inflation and, where applicable, an 'X' factor each year. In addition, APT Allgas 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 propose to approve the tariff variation mechanism proposed by APT Allgas as it does not properly constitute a weighted average price path as the formula it has used is not appropriate. The AER considers that APT Allgas's tariff variation mechanism does not comply with r. 92(2) of the NGR as the initial reference tariffs from reference services and 'X' factors must be amended to reflect the changes to the forecast total revenue identified in other chapters of this draft decision.

The AER has accepted the inclusion of a cost pass through mechanism. However, the AER does not accept APT Allgas's proposed general cost pass through event and considers that cost pass through should only be permitted where the costs of an event exceed a materiality threshold of one per cent of smoothed revenue.

11.1 Introduction

This chapter sets out the AER's consideration of APT Allgas'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 whilst 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

Rule 72(1)(k) of the NGR requires that the access arrangement information for a full access arrangement proposal must include the service provider's rationale for any proposed reference tariff variation mechanism.

Rule 92(1) of the NGR requires that a full access arrangement must include a mechanism for variation of a reference tariff over the course of an access arrangement period. Rule 92(2) of the NGR provides that the reference tariff variation mechanism must be designed to equalise in present value terms forecast revenue from reference services over the access arrangement period and the portion of total revenue allocated to reference services for the access arrangement period.

Rule 97(1) of the NGR requires that 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.

Rule 97(2) of the NGR provides that 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.

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 in r. 97(3) of the NGR including the need for efficient tariff structures; and the possible effects of the reference tariff variation mechanism on administrative costs; and the regulatory arrangements (if any) applicable to the relevant reference services; and the desirability of consistency between regulatory arrangements for similar services; and any other relevant factor.

Rule 97(4) of the NGR requires that a reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff.

11.3 Access arrangement proposal

APT Allgas has proposed two reference tariff variation mechanisms as part of its access arrangement proposal:[1]

- 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.

APT Allgas 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 4.5.2 of the access arrangement.[2]

11.3.1 Annual tariff variation formula mechanism

APT Allgas has proposed an annual tariff variation formula mechanism that is largely consistent with the formula applied in the earlier access arrangement period. However, an additional parameter for demand and volume customer tariffs has been added to adjust for UAG costs.

$$Revised\ Rate = Rate * (1 + CPI_{\%} - X_{Volume})*A$$

$$Revised\ Rate = Rate * (1 + CPI_{\%} - X_{Demand})*A$$

Where

X_{Volume} is the tariff adjustment factor applicable for the year from the adjustment date for volume class tariffs

1 APT Allgas, *Access arrangement submission*, September 2010, pp. 154–159.
2 APT Allgas, *Access arrangement proposal*, September 2010, pp. 11–13.

X_{Demand} is the tariff adjustment factor applicable for the year from the adjustment date for demand class tariffs

A is the unaccounted for gas (UAG) cost adjustment factor calculated as follows

$$A = [R_t + (UAG_{ta} - UAG_{tf})*UAG_{tv}] / R_t$$

Where

R_t forecast tariff revenue (volume and demand) for the applicable tariff year

UAG_{ta} actual contracted UAG cost for the applicable tariff year in $/GJ

UAG_{tf} forecast UAG cost for the applicable year in $/GJ

UAG_{tv} forecast UAG volume for the applicable tariff year in GJ

$CPI_{\%}$ is $(CPI_n - CPI_{n-1}) / CPI_n$

CPI_n is the CPI published in the quarter immediately before the adjustment date

CPI_{n-1} is the CPI published in the equivalent quarter in the year before the adjustment date

The proposed tariff variation formula mechanism would lead to an annual adjustment to reference tariffs for demand and volume customer services by:

- the change in the CPI
- the difference between forecast and actual UAG procurement costs for the coming year
- an X factor.

APT Allgas stated that the CPI adjustment formula remains unchanged from the earlier access arrangement and leads to a simple CPI adjusted price path over the access arrangement period. The UAG adjustment factor is intended to account for differences between forecast and actual market prices incurred by APT Allgas in procuring UAG over the access arrangement period.[3]

APT Allgas has retained the X factor adjustment in its annual tariff variation adjustment formula. The X factor applies to demand and volume customer service tariffs and smooths required tariff increases over the access arrangement period to minimise annual price increases experienced by end users.

APT Allgas has proposed to adjust the charge for the reference ancillary services in accordance with CPI only.

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[3] APT Allgas, *Access arrangement submission*, September 2010, pp. 154–156.

11.3.2 Cost pass through tariff mechanism

APT Allgas has included a cost pass through mechanism in its access arrangement proposal in order to recover incremental costs resulting from material unforeseen or uncontrollable events.[4] APT Allgas did not define any specific cost pass through events, opting instead for a general pass through because it:[5]

- avoided the limitations of the foresight required to comprehensively define events
- reflected recent regulatory practice by the AER
- is consistent with the revenue and pricing principles in the NGR.

APT Allgas proposed two materiality thresholds to apply to cost pass throughs:[6]

- for events where costs can be readily verified—the change in costs sufficient to change reference tariffs by the smallest increment
- for all other events—one per cent of APT Allgas's smoothed revenue requirement for the years in which the costs are incurred.

11.3.3 Annual tariff variation approval

APT Allgas has proposed a tariff variation process whereby annual changes in tariffs are notified to the AER at least 40 business days before they are scheduled to take effect. This notification may also include the impact of one or more cost pass through events, however cost pass through events may also be notified to the AER at any other time. APT Allgas submitted that the AER must notify APT Allgas of its decision in respect of a tariff variation notification within 30 business days of receiving a notification.

APT Allgas has proposed that if the AER does not make a decision within 30 business days, the relevant reference tariffs be automatically varied in accordance with the notification given by APT Allgas. However, if the AER subsequently decides against all or part of the variation, the AER may require APT Allgas to amend reference tariffs to take account of the AER's decision.

APT Allgas indicated that each tariff variation notification will include information on how the change in reference tariffs has been calculated, and if applicable, how any relevant change in costs associated with a cost pass through event have been derived or estimated. APT Allgas submitted that its proposed tariff variation process is consistent with r. 97(3) and r. 97(4) of the NGR.[7]

11.4 Submissions

AGL Energy (AGL) submitted that the APT Allgas's proposed timing for approval of annual tariff variations implies retailers receive only 10 business days notification for

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4 APT Allgas, *Access arrangement submission*, September 2010, p. 157.
5 APT Allgas, *Access arrangement submission*, September 2010, pp. 157–159.
6 APT Allgas, *Access arrangement submission*, September 2010, pp. 159–161.
7 APT Allgas, *Access arrangement submission*, September 2010, pp. 161–163.

the adjustment of tariffs, which it considered was not sufficient time.[8] AGL suggested the final approved network tariffs should be provided to all users at least 30 business days before 1 July, to allow sufficient time for determining new retail tariffs.

AGL also indicated that APT Allgas's access arrangement should include a requirement for APT Allgas to notify the AER for approval of variations to ancillary service tariffs. AGL suggested this notification should occur at least one month prior to the commencement of the variations.

11.5 AER's consideration

11.5.1 Annual tariff variation formula mechanism

11.5.1.1 Revenue equalisation

The purpose of the annual tariff variation mechanism over the access arrangement period is, amongst other things, to equalise in present value terms the building block costs associated with reference services and the portion of total revenue allocated to reference services.[9]

The AER considers that APT Allgas's annual tariff variation mechanism does not complies with r. 92(2) of the NGR, as the initial reference tariffs from reference services must be amended as set out in amendment 11.1. This is required to reflect the changes to forecast total revenue in the access arrangement period which occurs as a result of changes to the building block components that make up total revenue.[10] Further, amendment in forecast revenue is required to reflect changes to forecast demand. The changes in total revenue are outlined in the total revenue chapter 8 and changes to forecast demand are outlined in the demand chapter 9 of this draft decision.

11.5.1.2 Annual tariff variation formula

Specification of the tariff variation formula

While APT Allgas has presented the volume and demand customers as having separate price paths, in practice they do not. Instead, the X factors are the same for both types of customers due to the way APT Allgas has calculated the X factors. In the earlier access arrangement period, APT Allgas's tariff variation mechanism had two separate price paths for volume and demand customers.

While APT Allgas has described its proposed price paths as weighted average prices, the mathematical formula setting out the price paths does not represent a weighted average price approach. Indeed, were the prices paths approved in their current form, it is unclear how the formulas would be applied. For example, how the quantities are to be used to weight the average prices is not provided for in the formula. In the absence of this information, potentially, each existing tariff component would have to be adjusted by the same amount, which is not what the AER considers was intended by APT Allgas. Furthermore, APT Allgas may not be able to rebalance its tariffs in any

8 AGL, *Submission: Envestra access arrangement 2010–2015, 10 November 2009*, p. 4 (AGL, *Submission to the AER*, 26 November 2010).
9 NGR, r.92(2).
10 NGR, r.76.

way or introduce new tariff structures during the access arrangement period. The AER considers, therefore, that the proposed tariff variation formula is not specified correctly.

APT Allgas has included in its tariff variation formula an annual adjustment to account for any variance between the forecast price of gas used to calculate UAG and the actual price. The AER considered similar adjustments to annual tariffs to account for UAG costs proposed by the ActewAGL. [11] In its draft decision, the AER rejected the ActewAGL's proposal as it was overly complex and was likely to reduce the transparency for users about the cause of the tariff movements from year to year. However, the AER proposed that difference between forecast and actual costs associated with UAG be treated as a low materiality threshold cost pass through event.[12] Since the release of this draft decision, the AER has reviewed its position on such adjustments. The AER considers that APT Allgas, rather than network users, is better placed to manage the risks associated with variability of gas prices and how these may impact on the cost of UAG. Consequently, the AER requires APT Allgas to remove the annual tariff variation for the actual costs of UAG.

Side constraints

APT Allgas did not propose a side constraint be applied to its tariff variation mechanism. The AER is concerned that without a side constraint, APT Allgas would be able to rebalance tariffs in such a way that may significantly affect individual customers in a manner that is not consistent with the objects of the NGL[13] In particular, a side constraint would restrict year to year tariff adjustments and therefore avoid creating undesirable price volatility.

In order to address this issue, the AER requires APT Allgas to use a rebalancing variation formula that includes a side constraint on how much tariffs may change within tariff classes in any one year of the access arrangement period, as outlined in amendment 11.2(a).

The AER has had regard to the factors in r. 97(3) of the NGR and for the reasons outlined above does not accept the proposed tariff variation mechanism. The AER requires APT Allgas to use an alternate tariff variation mechanism as outlined in amendment 11.2.

The AER notes the side constraints contained in the rebalancing variation formula does not apply for the first year of the access arrangement period. The AER considers that APT Allgas should consult with its customers on tariff rebalancing in the first year of access arrangement following the release of the AER's draft decision. This would ensure customers are not surprised by one off large tariff increases in 2011–12 (changes in tariffs in the following years of the access arrangement period are limited by side constraints).

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11 AER, *Draft decision, ActewAGL access arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network, 1 July 20103– June 2015*, November 2009., pp. 120, 154–162 (AER, *ActewAGL draft decision*, November 2009).

12 AER, *ActewAGL draft decision*, November 2009, pp. 120, 154–162.

13 NGR, r. 97(3)(a).

11.5.1.3 Annual tariff variation approval

As outlined in amendment 11.3(i), APT Allgas 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. This means APT Allgas is required to provide a proposed tariff variation on or around 15 April or the next closest business day. This will provide the AER with approximately 30 business days to assess the tariff notification and users with 20 business days to implement the tariff changes. This will address the AGL's concern that a 10 business day notification period for retailers does not provide users sufficient time to adjust retail tariffs. This is also consistent with other regulatory arrangements for similar services.[14]

However, this is a short period of time for the AER to approve a tariff variation if an application is incomplete or information in it is not substantiated. As a result, the AER considers the access arrangement must be amended as outlined in amendment 11.3(i) to include a requirement to extend the decision making time period when the AER requests further information from APT Allgas. The arrangements to extend the decision making time is not new and a similar arrangement was allowed under the Code.[15]

APT Allgas 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 APT Allgas.[16] The AER considers that an automatic tariff adjustment is inappropriate as this does not provide the AER with sufficient oversight or powers of approval[17] for the annual tariff variation and needs to be amended as outlined in amendment 11.3(i).

APT Allgas has proposed to use CPI data published in the quarter immediately preceding the scheduled tariff change (on 1 July each year).[18] Consistent with its approach in other chapters of this draft decision, the AER requires APT Allgas to use March quarter CPI data for its annual tariff variations.[19] CPI calculation approach is outlined in the amendment 3.2.

An important input in the proposed annual tariff variation mechanism is the use of past gas quantities to weight each tariff components. The AER considers it is appropriate that APT Allgas be required to provide an independent statement to support the actual gas quantities to allow the AER to verify the quantities used in the tariff variation mechanism, and to ensure it is applied consistently every year.[20] The independent verification statement should provide for audited or verified quarterly and annual quantities for the year consistent with the proposed changes in CPI. This information will likely be collected as part of annual reporting requirements (audit requirement to be set out in RIN). The information to be reported during the access arrangement period is outlined in appendix E. The AER requires APT Allgas to amend its access arrangement proposal as outlined in amendment 11.3(ii).

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14 NGR, r. 97(3)(d).
15 Code, annex D, section 8.3D (b)(ii).
16 APT Allgas, *Access arrangement submission*, September 2010, p. 162.
17 NGR, r. 97(4).
18 APT Allgas, *Access arrangement submission*, September 2010, pp. 154–155.
19 NGR, r. 97(3)(e).
20 NGR, r. 97(3)(e).

Further, the AER considers that APT Allgas should provide its workings, demonstrating how the proposed tariffs have been calculated in accordance with the tariff variation mechanism. This will allow the AER to more easily assess whether the tariff variation mechanism has been applied correctly and facilitate the administrative efficiency of the approval process.[21] The AER requires APT Allgas to amend its access arrangement proposal as outlined in amendment 11.3(i).

11.5.2 Tariff variation mechanism for cost pass through

The AER considers a 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 customers 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.

11.5.2.1 Proposed cost pass through event

The AER does not accept APT Allgas's proposed cost pass through mechanism. APT Allgas proposed a general pass through event, instead of proposing defined events.[22] The AER has approved a general cost pass through event in previous decisions.[23] In developing the definition of the general pass through event in those decisions, the AER acknowledged that certain events were uncontrollable and unforeseeable, as noted by APT Allgas.[24] 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 is discussed in the AER's decision for the Victorian electricity distribution network service providers distribution determination (Victorian DNSPs).[25]

The AER acknowledges that not accepting the general cost pass through event proposed by APT Allgas is not consistent with its decision to approve a general cost pass through for NSW gas service providers.[26] However, as the AER noted in its final decision for the Victorian DNSPs, any change in its regulatory approach necessarily results in some inconsistency across jurisdictions for a finite period. As noted at the time, this is because regulatory control periods (and applicable distribution determinations) are not concurrent across jurisdictions and do not have uniform commencement dates. The AER considers that it is undertaking its first cycle of distribution determinations and that the positions reached may take some time to settle as its regulatory approach evolves over time.[27] The AER considered that it was appropriate to reject a general pass through event in the Victorian distribution

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21 NGR, r. 97(4).
22 APT Allgas, *Access arrangement submission*, September 2010, p. 157.
23 AER, *Draft decision, Queensland distribution determination*, November 2009, pp. 326–348; AER, *Final decision, Queensland distribution determination*, May 2010, pp. 223–242
24 APT Allgas, *Access arrangement submission*, September 2010, p. 157.
25 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 711–712.
26 AER, *Draft decision, Jemena access arrangement proposal for the NSW gas networks*, February 2010, p. 297.
27 AER, *Final decision, Victorian distribution determination*, October 2010, p. 795.

determination.[28] The AER indicated that—unless there was good reason for the reintroduction of such an event, the AER intended that its rejection of the general pass through event would apply in future distribution determinations.[29] Similarly, the AER considers that the general cost pass through event proposed by APT Allgas should not be accepted.

The AER considers that firmly defining cost pass through events in advance would minimise regulatory uncertainty during the access arrangement period. This would mitigate the possibility of a high magnitude event putting the financial viability of APT Allgas at risk.[30] The AER considers that this aim is achieved by removing the general pass through event and replacing it with defined cost pass through events.[31] 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 APT Allgas.[32]

The AER's decision to reject the general pass through for Victorian DNSPs was also based on the AER's view that the general pass through undermined the incentive arrangements within the regulatory regime.[33] In coming to this view, the AER noted—and maintains—the following concerns about general pass throughs held by the ESCV:

- it would be difficult to accurately assess the scope of general pass through events should they occur

- information asymmetry between the DNSP and the regulator would make it extremely difficult to identify where exogenous changes had resulted in a cost decrease for a distributor. Intrusive and heavy handed regulation and monitoring would need to be introduced to identify any cost decreases and ensure that the full effects of these were passed through to customers. This would impose large resource costs on the distributors and on the regulator.[34]

APT Allgas stated that its proposed general pass through event is consistent with arrangements in the earlier access arrangement, in which cost pass through events were not specifically defined.[35] The AER does not accept this statement, because the QCA required APT Allgas's pass through events to be defined as follows:

- a change in taxation or other statutory charges

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28 AER, *Final decision, Victorian distribution determination*, October 2010, pp. 794–795.
29 AER, *Final decision, Victorian distribution determination*, October, 2010, p. 795.
30 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 718–720.
31 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 719.
32 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 722.
33 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 719.
34 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 721.
35 APT Allgas, *Access arrangement submission*, *September* 2010, p. 158.

- any other major change in government policy, for example, costs associated with the introduction of full retail contestability.[36]

The AER considers these events are broadly consistent with what the AER considers to be a 'defined' event. As a result, the AER considers that its decision not to accept APT Allgas's proposed general cost pass through is consistent with the cost pass through provisions of the earlier access arrangement. The AER has 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.

11.5.2.2 Defined pass through events

The AER considers that clearly defined events are in the long term interests of service providers and users of gas distribution networks.. The AER's final decision for the Victorian DNSPs set out a framework of defined pass through events, based on the AER's updated and preferred approach to assessment of cost pass through events.[37] The AER had regard to the need to provide a clear set of events that balanced the distribution of risks between the service provider and network users, while avoiding ambiguity, excessive administrative costs and overlap of events. The AER considers that a clearly defined framework of cost pass through events is effective in promoting the national gas objective and the NGL revenue and pricing principles.[38] For the purposes of this access arrangement, the event definitions have been updated to reflect the services provided by gas distributors

However, the AER notes that the retailer of last resort (ROLR) event included in the Victorian decision is not directly applicable to APT Allgas. Nonetheless, APT Allgas faces the clearly defined risk of network user failure, and that a network user failure may affect APT Allgas's ability to provide reference services. Such a failure is likely to be out of APT Allgas's control; and is not otherwise provided for in the NGR, or by other elements of the access arrangement. In order to preserve long term security and reliability of gas supply, the AER considers it is appropriate to provide some protection for APT Allgas against network user failure. The 'network users' relevant to APT Allgas will generally be gas retailers. The AER considers that the 'network user failure event' set out below mirrors the effect of a ROLR event, and addresses the risk of network user failure as it is relevant to APT Allgas. For these reasons, the AER considers this event promotes the national gas objective, and satisfies the NGR revenue and pricing principles.[39]

The AER considers the following cost pass through events are preferable to the general event proposed by APT Allgas, and should apply in place of APT Allgas's proposed events for the access arrangement period:

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36 QCA, *Draft decision, Revised access arrangement for gas distribution networks: Allgas Energy*, December 2005, p. 34

37 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 716-717.

38 NGL s. 23 and NGL s. 24 respectively.

39 NGL s. 23 and NGL s. 24 respectively.

- **Regulatory change event**—means:

A change in a regulatory obligation or requirement that:

(a) occurs during the course of a regulatory control period; and

(b) substantially affects the manner in which APT Allgas provides reference services (as the case requires); 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 a regulatory control period, the manner in which APT Allgas is required to provide a reference service; or

(ii) imposing, removing or varying, during the course of a regulatory control period, minimum service standards applicable to prescribed reference services; or

(iii) altering, during the course of a regulatory control period, the nature or scope of the prescribed reference services, provided by APT Allgas; and

(b) materially increases or materially decreases the costs to APT Allgas of providing prescribed reference services.

- **Tax change event**—means:

A tax change event occurs if any of the following occurs during the course of a regulatory control period for APT Allgas:

(a) 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;

(b) the removal of a relevant tax;

(c) the imposition of a relevant tax; and

In consequence, the costs to APT Allgas of providing prescribed reference services are materially increased or decreased.

- **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), 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 APT Allgas of providing a reference service.

- **Network user failure event**—means:

A network user failure event means the occurrence of an event whereby an existing network user is unable to continue to supply gas to its customers, and those customers are transferred to another network user, and which materially increases the costs of APT Allgas providing reference services.

- **Insurer credit risk event—**means:

An event where the insolvency of the nominated insurers of APT Allgas occurs, as a result of which APT Allgas:

(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 APT Allgas'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 APT Allgas 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 APT Allgas'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 APT Allgas's negligence, fault, or lack of care. This also excludes all liability arising from the APT Allgas's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by APT Allgas.

- **Natural disaster event**—means:

Any major fire, flood, earthquake, or other natural disaster beyond the control of APT Allgas (but excluding those events for which external insurance or self insurance has been included within APT Allgas's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to APT Allgas of providing reference services.

The AER notes that the event definitions have been revised to the least extent possible, in order to reflect the appropriate participants and terminology of gas distribution services. In particular, the AER notes that the 'network user failure event' is defined to

mirror the effect of the ROLR event approved in the Victorian final decision,[40] to the extent it applies to APT Allgas.

11.5.2.3 Materiality thresholds

APT Allgas proposes to apply a materiality threshold of one per cent of smoothed revenue to some cost pass through events.[41] However, the AER does not accept APT Allgas's lower proposed materiality threshold for 'readily verifiable' cost pass through events.[42] The fundamental purpose of the cost pass-through mechanism is to offer protection to service providers, where unexpected events place the financial viability of the service provider at risk. It is not intended to recover all costs that a business would otherwise be expected to absorb. The AER considers APT Allgas's lower proposed materiality threshold is too low, and would reduce the incentive for APT Allgas to mitigate the risk and costs of a pass through event.

Under r. 97(3), and r. 97(4) of the NGR, the AER must have regard to the regulatory arrangements in place in the previous tariff variation mechanism[43] and the desirability of consistency in the mechanism, within and beyond the relevant jurisdiction.[44] In its most recent decision for the Victorian DNSPs, the AER considered the role that pass throughs should play in the regulatory regime.[45] As part of this review, the AER considered the appropriate risk sharing that should occur between customers and service providers, and the extent to which costs from unexpected events need to be recovered by service providers. To summarise, the AER considered that:

- the fundamental function of the pass through regime is that some costs from unexpected events be passed through to network users to protect DNSPs' financial viability

- providing 100 per cent recovery for all costs incurred is not consistent with promoting the national electricity objective, in promoting the long term interests of consumers with respect to price. To permit the annual pass through of all costs incurred would create a price volatility which is undesirable for customers (where non-recovery of those costs does not present a situation where the security or reliability of the network is undermined)

- such a cost of service regime may impact on the efficiency incentives of the DNSPs, because it would remove the incentive for DNSPs to mitigate costs from unexpected events

- full recovery of costs would be inconsistent with the revenue and pricing principles, particularly s.7A (3) of the NEL, which compels the AER to provide incentives for DNSPs to act efficiently.[46]

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40 AER, *Draft decision, Victorian distribution determination*, June, 2010, pp. 724.
41 APT *Allgas, Access arrangement Submission*, September 2010, p. 161.
42 APT Allgas, *Access arrangement Submission,* September 2010, pp. 159–161.
43 NGR r. 97(3)(c).
44 NGR r. 97(3)(d).
45 AER, *Draft decision, Victorian distribution determination*, June 2010, pp. 761-765.
46 AER, *Final decision, Victorian distribution determination*, October 2010, 760–775.

The AER considers that the national gas and electricity objectives are very similar.[47] Likewise, the AER considers the revenue and pricing principles under the NGL and NEL are consistent.[48] As such, the AER considers that its reasoning on low materiality thresholds in its Victorian DNSPs decision, summarised above, is applicable to this gas access arrangement review. The AER considers that APT Allgas's materiality threshold for readily verifiable events is too low, and limits the efficiency incentives for APT Allgas to mitigate the costs of such events. A materiality threshold of one per cent better accommodates these efficiency incentives, and better promotes the revenue and pricing principles under the NGL.[49]

The AER notes that all of APT Allgas's cost pass through events have previously been subject to a materiality threshold of 'one per cent of forecast annual revenue'.[50] In addition, one per cent materiality thresholds were applied by the QCA, and by IPART in previous energy determinations.[51] Several businesses including Ergon Energy and Country Energy have accepted a one per cent materiality threshold for specified cost pass through events. The AER is not aware of any service providers that have failed to meet service obligations due to the operation of the materiality threshold, and the resultant inability to pass through costs to customers.[52]

APT Allgas has proposed that a low materiality threshold should be applied to readily verifiable events. The AER acknowledges it has approved a low materiality threshold in previous decisions.[53] At that time, the AER considered that a lower materiality threshold should apply to events for which the efficient costs can be readily verified, as noted by APT Allgas.[54] However, as noted earlier the AER has since undertaken significant analysis of its approach to cost pass through, and no longer considers this lower threshold is appropriate. The AER accepts that some inconsistency across jurisdictions for a finite period is inevitable, given regulatory periods are not concurrent. The AER considers that its preferred approach to cost pass through—and specifically materiality thresholds—is preferable to APT Allgas's proposed approach under the NGL and NGR. Specifically, the AER considers a one per cent materiality threshold best promotes the national gas objective, and the revenue and pricing principles under the NGL.[55]

Under r. 40(3) of the NGR, the AER can withhold approval of proposed cost pass through arrangements where the AER considers a preferable alternative exists. A preferable alternative must comply with applicable requirements and criteria under the NGL. As part of this discretion, the AER is able to set defined cost pass through events, and to set a materiality threshold for those events. [56] For the reasons discussed, the AER

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47 NGL, s. 23; NEL, s. 7.
48 NGL, s. 24; NEL, s. 7A.
49 NGL, s. 24.
50 QCA, *Final decision, Revised access arrangement for gas distribution networks: Allgas Energy*, May 2006, p. 36.
51 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.
52 AER, *Final decision, South Australian distribution determination*, May 2010, p. 236
53 AER, *Final decision, Australian Capital Territory distribution determination, 2009–10 to 2013–14*, April 2009, p. 130.
54 APT Allgas, *Access arrangement submission*, September 2010, p. 160.
55 NGL, s. 23 and s. 24 respectively.
56 NGR, r. 97.

considers that the one per cent revenue threshold proposed by APT Allgas for non readily-verifiable events should apply to all pass through events. The AER considers the materiality threshold should be defined as set out in amendment 11.5.

11.5.2.4 Cost pass through assessment criteria

In the access arrangement proposal, APT Allgas stated that reference tariffs may be varied if one or more cost pass through events occur, or are reasonably expected to occur.[57] Likewise, APT Allgas proposed that the impact of events that 'are expected to lead to changes in costs' can be passed through.[58] The AER does not accept these descriptions, and considers that the cost pass through mechanism only applies 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 of businesses for impacts that have not yet occurred would not achieve this purpose.

The AER considers that APT Allgas'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
- 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.[59]

APT Allgas'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.

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57 APT Allgas, *Access arrangement proposal*, September 2010, p. 13.
58 APT Allgas, *Access arrangement proposal*, September 2010, p. 13.
59 AER, *Draft decision, Jemena access arrangement proposal for the NSW gas networks*, February 2010, p. 301; NGR, r. 97(3)(e).

11.5.2.5 Oversight procedures and powers of approval for the cost pass through tariff variation mechanism

Under r. 97(4) of the NGR, the reference tariff variation mechanism must give the AER sufficient powers of oversight or approval. The AER does not consider APT Allgas'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 APT Allgas 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 APT Allgas 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. Time periods for the notification of cost pass through events are mandated under r. 6.6.1 of the NER. The AER considers that there is no reason to expect that cost pass through applications for electricity service providers should be any less complex than those for gas service providers. 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 11.5. The AER considers this will improve the clarity of the process and requirements for APT Allgas and for network users.

11.6 Conclusion

The AER does not propose to approve the tariff variation mechanism proposed by APT Allgas as it does not comply with r. 97 of the NGR, and requires APT Allgas to make the amendments set out below.

The AER also does not accept APT Allgas's proposed general cost pass through event. The AER considers that defined cost pass through events should apply to APT Allgas, all subject to a materiality threshold of one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred. These events are defined in amendment 11.5.

The AER considers the description of the materiality threshold[60], and the description of the cost pass through mechanism[61] should be defined in the access arrangement as set out in section 11.6.

11.7 Required amendments

Before the access arrangement proposal can be accepted, APT Allgas must make the following amendments:

Amendment 11.1: amend the access arrangement proposal to delete tables 1–6 of the tariff schedule 2011–12 and replace with the following updated tables:

[60] Section 11.5.2.3.
[61] Section 11.5.2.4.

The initial reference tariffs are expressed in nominal terms and first annual tariff variation is made for the year commencing 1 July 2012.

Table 1: Volume Tariffs for 2011-12 - GST exclusive dollars

Network Charges		
Base Charge	($/day)	0.5410
Up to 1.7 GJ of gas delivered per day	($/GJ/day)	8.8990
Next 8.3 GJ of gas delivered per day	($/GJ/day)	6.5252
All gas delivered over 10 GJ per day	($/GJ/day)	4.8580

Table 2: Demand Tariffs for 2011-12 – Brisbane Region - GST exclusive dollars

Network Charges		**Zone 1**	**Zone 2**	**Zone 3**
		DZ01	**DZ02**	**DZ03**
Base Charge (MHQ	($/GJ of MHQ/day)	2.1140	3.0076	2.5112
MDQ of 50GJ or less	($/day)	1.5530	2.2479	2.5377
Greater than 50GJ but not greater than125 GJ of MDQ	($/day)	0.8612	1.6009	2.5726
Greater than 125GJ but not greater than 275 GJ of MDQ	($/day)	0.6073	1.3249	1.9101
Greater than 275GJ but not greater than 525 GJ of MDQ	($/day)	0.2650	0.6183	1.0489
Greater than 525GJ of MDQ	($/day)	0.2319	0.2429	0.2871

Table 3: Demand Tariffs for 2011-12 – South Coast Region -GST exclusive dollars

Network Charges		**Zone 4**	**Zone 5**	**Zone 6**
		DZ04	**DZ05**	**DZ06**
Base Charge (MHQ	($/GJ of MHQ/day)	1.8728	3.7928	3.7979
MDQ of 50GJ or less	($/day)	3.1211	3.1195	3.2708
Greater than 50GJ but not greater than125 GJ of MDQ	($/day)	2.8265	2.9811	3.1467
Greater than 125GJ but not greater than275 GJ of MDQ	($/day)	2.4290	2.5726	2.6940
Greater than 275GJ but not greater than 525 GJ of MDQ	($/day)	2.0426	2.2082	2.3076
Greater than 525GJ of MDQ	($/day)	1.7776	1.9211	2.0095

Table 4: Demand Tariffs for 2011-12 – Toowoomba Region - GST exclusive dollars

Network Charges		**Zone 7**	**Zone 8**
(Exclusive of GST)		**DZ07**	**DZ08**
Base Charge (MHQ	($/GJ of MHQ/day)	2.1219	3.9041
MDQ of 50GJ or less	($/day)	1.2015	1.5568
Greater than 50GJ but not greater than125 GJ of MDQ	($/day)	0.3975	0.8391
Greater than 125GJ but not greater than275 GJ of MDQ	($/day)	0.3202	0.6514
Greater than 275GJ but not greater than 525 GJ of MDQ	($/day)	0.2650	0.4416
Greater than 525GJ of MDQ	($/day)	0.2429	0.2539

Table 5: Demand Tariffs for 2011-12 – Oakey Region - GST exclusive dollars

Network Charges		**Zone 9**	**Zone 10**
(Exclusive of GST)		**DZ09**	**DZ10**
Base Charge (MHQ	($/GJ of MHQ/day)	1.9338	2.0647
MDQ of 50GJ or less	($/day)	1.2655	2.7649
Greater than 50GJ but not greater than125 GJ of MDQ	($/day)	0.5079	2.5946
Greater than 125GJ but not greater than275 GJ of MDQ	($/day)	0.4196	2.0867
Greater than 275GJ but not greater than 525 GJ of MDQ	($/day)	0.2981	1.2808
Greater than 525GJ of MDQ	($/day)	0.2429	0.5521

Table 6: Reference Ancillary Services charges for 2011-12 - GST exclusive dollars

Reference Ancillary Service		**Charges**
Special Meter Read	($/each)	18.96
Inlet Disconnection	($/day)	52.05
Inlet Reconnection	($/day)	66.14

Amendment 11.2: amend the access arrangement proposal to delete section 4.5.2 and replace it with the following:

The Service Provider will implement its CPI-X price path for the Financial Years commencing on or after 1 July 2012 using the Annual Tariff Variation Mechanism specified as the following formula:

Tariff Control Formula

$$(CPI_t)((1-X_t) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \bullet q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \bullet q_{t-2}^{ij}}$$

where:

CPI_t is calculated as the CPI for the year ending 31 March immediately preceding the start of year t, divided by the CPI for the year ending 31 March immediately preceding the start of year t-1;

X_t is defined by the alignment of the Service Provider's building block revenue requirement with the NPV of its forecast revenues and is determined to be:

X_t is -0.04 for 2012–13

X_t is -0.03 for 2013–14

X_t is -0.03 for 2014–15

X_t is -0.02 for 2015–16

n is the number of different Reference Tariffs

m is the different components, elements or variables ('components') comprised within a Reference Tariff

p_t^{ij} is the proposed component *j* of Reference Tariff *i* in year *t*

p_{t-1}^{ij} is the prevailing component *j* of Reference Tariff *j* in year *t–1*, and

q_{t-2}^{ij} is the quantity of component *j* of Reference Tariff *j* that was sold in year *t–2*

Amendment 11.2(a): amend the access arrangement proposal to delete section 4.5.2 and replace it with the following:

Rebalancing Control Formula

$$(CPI_t)((1-X_t)(1+Y_t) \geq \frac{\sum_{j=1}^{m} p_t^{j} \bullet q_{t-2}^{j}}{\sum_{j=1}^{m} p_{t-1}^{j} \bullet q_{t-2}^{j}}, i = 1,....n$$

where:

CPI_t is calculated as the CPI for the year ending 31 March immediately preceding the start of year t, divided by the CPI for the year ending 31 March immediately preceding the start of year *t-1*;

X_t is defined by the alignment of the Service Provider's building block revenue requirement with the NPV of its forecast revenues and is determined to be:

X_t is -0.04 for 2012–13
X_t is -0.03 for 2013–14
X_t is -0.03 for 2014–15
X_t is -0.02 for 2015–16
Y_t is 0.02
n is the number of different Reference Tariffs
m is the different components, elements or variables ('components') comprised within a Reference Tariff
p_t^{ij} is the proposed component *j* of Reference Tariff *i* in year *t*
p_{t-1}^{ij} is the prevailing component *j* of Reference Tariff *j* in year *t–1*, and
q_{t-2}^{ij} is the quantity of component *j* of Reference Tariff *j* that was sold in year *t–2*

Price Adjustments for Reference Ancillary Services

The charge for the Reference Ancillary Services will be adjusted in accordance with CPI.

Revised Rate = Rate * (1+ CPI%)

All revised Reference Tariffs will be rounded to the same number of decimal places for that Reference Tariff as provided in Appendix B of this Access Arrangement.

Amendment 11.3: remove references to 'Cost Pass-through events' from section 4.5.4 in the access arrangement proposal and amend this section as follows:

(i) delete section 4.5.4 and replace it with following:

> APT Allgas will notify the Regulator 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 APT Allgas proposes variations to the Reference Tariffs (otherwise than as a result of a Cost pass through event) and those various 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 Regulator.

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 the Service Provider's Variation Notice, the AER will inform the Service Provider in writing of whether or not it has verified the proposed Haulage Reference Tariff and/or Haulage Reference Tariff Components in the Service Provider's Variation Notice as compliant with the Annual Tariff Variation Mechanism.

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.

(ii) APT Allgas will include a statement to support the Gas Quantity inputs in the tariff variation formula. The statement will be independently audited or verified and the Quantity input must reflect the most recent actual annual quantities available at the time of tariff variation assessment. The actual Quantity will be provided as four quarters of Gas Quantity data reconciling to an annual total Quantity of Gas.

Amendment 11.4: insert a new section after section 4.5.3 before what is currently section 4.5.4 in the access arrangement as follows:

4.5.X Procedure for Cost Pass through Event Variation in Reference Tariffs

APT Allgas 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, APT Allgas will provide the AER with a statement, signed by an authorised officer of APT Allgas, 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 will endeavour to make its decision on whether APT Allgas should vary Reference Tariffs due to the occurrence of a Cost Pass-through within 90 business days of receiving a notification from APT Allgas. However, if the AER determines the difficulty of assessing or quantifying the effect of the relevant Cost Pass-through requires further consideration, the AER may require an extension of a specified duration. The AER will notify APT Allgas of the extension, and its duration, within 90 business days of receiving a notification from APT Allgas.

Amendment 11.5: amend the access arrangement proposal to delete section 4.5.3 in the access arrangement and replace it with the following:

Subject to the approval of the regulator 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 final decision, in the years of the regulatory control 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
- a network user failure 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 a regulatory control period; and

(b) substantially affects the manner in which APT Allgas provides reference services (as the case requires); 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 a regulatory control period, the manner in which APT Allgas is required to provide a reference service; or

(ii) imposing, removing or varying, during the course of a regulatory control period, minimum service standards applicable to prescribed reference services; or

(iii) altering, during the course of a regulatory control period, the nature or scope of the prescribed reference services, provided by APT Allgas; and

(b) materially increases or materially decreases the costs to APT Allgas of providing prescribed reference services.

‘**Tax change event**’ means:

A tax change event occurs if any of the following occurs during the course of a regulatory control period for APT Allgas:

(a) 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;

(b) the removal of a relevant tax;

(c) the imposition of a relevant tax; and

In consequence, the costs to APT Allgas of providing prescribed reference services are materially increased or decreased.

‘**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), 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 APT Allgas of providing a reference service.

'**Network user failure event**' means:

A network user failure event means the occurrence of an event whereby an existing network user is unable to continue to supply gas to its customers, and those customers are transferred to another network user, and which materially increases the costs of APT Allgas providing reference services.

'**Insurer credit risk event**' means:

An event where the insolvency of the nominated insurers of APT Allgas occurs, as a result of which APT Allgas:

(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 APT Allgas'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 APT Allgas 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 the APT Allgas'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 APT Allgas's negligence, fault, or lack of care. This also excludes all liability arising from the APT Allgas's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by APT Allgas.

'**Natural disaster event**' means:

Any major fire, flood, earthquake, or other natural disaster beyond the control of APT Allgas (but excluding those events for which external insurance or self insurance has been included within APT Allgas's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to APT Allgas 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 regulatory control period that the costs are incurred.

Amendment 11.6: Amend the access arrangement information to reflect amendments to reflect amendments **11.1**–**11.5** as appropriate.

Part C – Other provisions of an access arrangement

12 Non-tariff components

APT Allgas 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 network service provider and users. Some of the terms and conditions vary from those included in the earlier access arrangement.

The AER proposes to approve some of the terms and conditions of APT Allgas'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 in 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 accepts APT Allgas's proposals in relation to queuing requirements and the review commencement date proposed by APT Allgas as both meet the requirements of the NGR and the NGL. The AER also proposes to approve APT Allgas's proposal not to include queuing requirements in its access arrangement proposal.

The AER proposes not to approve a number of the non-tariff components of APT Allgas's access arrangement proposal, including capacity trading requirements; extensions and expansions policy; the review submission date; and the lack of a trigger event for the acceleration of the review submission date. The AER considers that amended arrangements for these components better promote the national gas objective in s. 23 of the NGL.

12.1 Introduction

This chapter sets out the AER's consideration of the non-tariff components of APT Allgas's access arrangement proposal. In order to demonstrate compliance with r. 48 of the NGR, APT Allgas's access arrangement proposal includes:

- the terms and conditions that form the basis of the relationship between APT Allgas and its customers;
- capacity trading arrangements that allow users to transfer contracted capacity to other users;
- 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; and
- dates for reviewing the proposed access arrangements and commencing the next access arrangements.

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.[1] However, in considering APT Allgas's proposed terms and conditions the AER has had regard to rule 100 of the NGR.

Rule 100 requires that an access arrangement be consistent with the national gas objective 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.[2]

The AER has full discretion in assessing APT Allgas's proposed terms and conditions. Full discretion means that the AER has a 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.[3]

12.2.2 Access arrangement proposal

APT Allgas's proposed terms and conditions are attached to the access arrangement and form the basis of the access agreement between APT Allgas and a user.[4]

While APT Allgas proposed some changes to its terms and conditions, APT Allgas submitted that they remain largely unchanged from the current terms and conditions.[5] The proposed revisions relate to:

- MDQ overruns (clause 3.2)
- requests for reductions in MDQ (clause 3.3)
- pass through of costs (clause 9).

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1 This contrasts with section 3.6 of the Code, which specifically required the regulator to assess whether the terms and conditions were reasonable.
2 NGL, s. 23.
3 NGR, r. 40(3).
4 APT Allgas, *Access arrangement proposal*, September 2010, Terms and conditions.
5 APT Allgas, *Access arrangement submission*, September 2010, p. 13.

The terms and conditions relating to requests for reductions in MDQ are new provisions. APT Allgas submitted that these new terms and conditions formalise arrangements by which users can request a reduction in MDQ.[6]

12.2.3 Submissions

Submissions were received from AGL and Origin, covering several aspects of APT Allgas's proposal.[7] The submissions relate not only to APT Allgas's proposed amendments, but also to existing terms and conditions for which APT Allgas proposed no revisions.

12.2.4 AER's consideration

The AER's assessment of APT Allgas's proposed terms and conditions and issues raised in submissions is set out in detail in appendix D.

In assessing APT Allgas's proposed revisions and AGL's and Origin's submissions the AER has had regard to the national gas objective. The AER considers that in order to achieve the national gas objective 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 network or provide adequate services. This would not be in the long term interests of natural gas consumers.

Origin submitted that a number of terms and conditions should be reciprocal. The AER considers that it is fair and reasonable for some of these terms and conditions to be made reciprocal. Accordingly, the AER requires certain amendments.

Overall, the AER considers that taken in aggregate the terms and conditions are weighted too much in favour of APT Allgas. To correct this imbalance the AER requires APT Allgas to amend a number of terms and conditions. The remainder of this section summarises the proposed terms and conditions which the AER requires to be amended.

12.2.4.1 Determination of a customer

Clause 2.2 provides that APT Allgas will determine from time to time whether an end user is a volume customer or a demand customer. The determination is binding on the user.[8]

The AER considers that clause 2.2 is ambiguous and may be construed as giving APT Allgas absolute discretion. APT Allgas is required to amend its access

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6 APT Allgas, *Access arrangement submission*, September 2010, p. 13.

7 AGL, *APT Allgas's access arrangement*, November 2010; Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010.

8 All references to 'clauses' relate to the terms and conditions of APT Allgas's access arrangement proposal, unless otherwise stated.

arrangement to provide that clause 2.2 is subject to clauses 2.1.1 and 2.1.2 of the access arrangement (which set out the criteria for determining the status of an end user),[9] as set out at amendment 12.1.

12.2.4.2 Requests for reduction in MDQ

For demand customer delivery points, clause 3.3.1(b) provides that, prior to APT Allgas agreeing to a user's request for a reduction in MDQ, the user's customer must not have taken delivery of a quantity of gas equal to or in excess of 90 per cent of its MDQ for at least 12 months. Clause 3.3.8 has the same time period with respect to requests for subsequent reductions in MDQ. Clause 3.3.9 provides that if a request is refused, the user must wait at least six months before lodging a further request.

The AER considers that APT Allgas should clarify that a new demand customer does not have to wait up to 12 months for the MDQ at the relevant delivery point to be reduced. APT Allgas is required to amend its terms and conditions to clarify that nothing in clause 3.3 prevents a new MDQ for a demand customer delivery point to be agreed on when the demand customer at the delivery point changes, as set out at amendment 12.2, 12.3 and 12.4.

Clause 3.3.6 provides that, if requested by a user, APT Allgas will provide an explanation for rejecting a request for a reduction in MDQ. The AER considers that APT Allgas should respond in a timely manner. APT Allgas is required to amend its terms and conditions to provide that it will respond to such requests as soon as practicable, as set out at amendment 12.5.

12.2.4.3 Delivery point pressures

Clause 5.2.1 requires APT Allgas to deliver gas at a minimum pressure of 1.125 kPa, but always within the pressure range specified by APT Allgas from time to time.

The AER considers that APT Allgas's ability to specify the delivery pressure range should be subject to any pressure range prescribed by law. APT Allgas is required to amend clause 5.2.1 as set out at amendment 12.6.

Clause 5.2.2 sets out the circumstances under which APT Allgas is excused from liability for a breach of clause 5.2.1. APT Allgas is excused from liability irrespective of whether or not APT Allgas was aware of those circumstances.

The AER requires an amendment to clarify that APT Allgas is not relieved of its obligations if the failure to deliver gas within the range of pressures is due to its negligence, as set out at amendment 12.7.

12.2.4.4 Incorrect tax invoices

Clause 8.7 provides that a user may not claim from APT Allgas any amount overcharged if more than 12 months has elapsed since the date of the invoice.

The AER considers it appropriate that any claims that a user is required to pursue by law should not be subject to the 12 month time period. APT Allgas is required to

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[9] APT Allgas, *Access arrangement proposal*, October 2010, pp. 5–6.

amend clause 21 to exempt any claims a user is required to make by law on behalf of a customer, as set out at amendment 12.8.

12.2.4.5 Cost pass through of new or changed obligations

APT Allgas proposed revisions to the terms and conditions associated with an increase or decrease in the costs of an obligation (for example, a tax) imposed on APT Allgas (a cost pass through event).

The AER requires APT Allgas to amend clause 9 to clarify that the reference to a cost pass through event is consistent with the definition contained in the access arrangement. The AER also requires an amendment to clarify that the mechanism reasonably determined by APT Allgas must be approved by the AER. APT Allgas is required to amend its terms and conditions as set out at amendments 12.9 and 12.10.

12.2.4.6 Information and assistance

Clause 10 provides that a user is required to provide APT Allgas with whatever information, assistance and cooperation APT Allgas might reasonably require.

The AER considers that it is reasonable for these arrangements to be reciprocal. The AER considers it appropriate that either party should provide the other party with whatever information and assistance it reasonable requires. APT Allgas is required to amend clause 10 as set out at amendment 12.11.

12.2.4.7 Insurance

Clause 13 sets out the terms and conditions relating to the insurance policies that users are required to take out. Those terms and conditions include a requirement for users to obtain APT Allgas's approval of all the terms of each insurance policy (clause 13.1(b)). They also provide that, whenever reasonably requested by APT Allgas, users must give APT Allgas:

- copies of the insurance policy (clause 13.1(c)(i))
- certificates of currency (clause 13.1(c)(ii))
- other information (clause 13.1(c)(iii)).

Clause 13.2 requires users to consult with APT Allgas on insurance claims.

The AER does not consider that it is reasonable for users to be required to provide copies of insurance policies to APT Allgas. In addition, the AER does not consider users should be required to seek APT Allgas's approval of the terms of insurance policies. The AER requires APT Allgas to delete clauses 13.1(b), 13.1(c)(i) and 13.1(c)(iii) of its proposed terms and conditions, as set out at amendment 12.12.

The AER also requires APT Allgas to amend clause 13.2 to clarify that the claim must relate to APT Allgas's network only, and to delete clause 13.2(c), as set out at amendment 12.13.

12.2.4.8 Consequential loss

Clause 14.1 provides the neither APT Allgas nor the user is liable for 'Consequential Loss'.

It appears that it is APT Allgas's intention that the term 'Consequential Loss' should be a defined term. APT Allgas is required to update its glossary to include a definition of 'Consequential Loss', as set out at amendment 12.14.

12.2.4.9 Warranties, indemnities and limitation of liability

Clause 14.3 provides that any claim by a user against APT Allgas is limited to $100,000 in any one year.

The AER considers that this arrangement should be reciprocal and it is appropriate that any claim by ATP Allgas against a user should also be limited. APT Allgas is required to amend clause 14.3 as set out at amendment 12.15.

Clause 14.4(c) provides that nothing in an access agreement excludes or limits the application of any provision of any statute (including the *Trade Practices Act 1974*).

The AER considers that clause 14.4(c) needs to be updated to reflect that the *Competition and Consumer Act 2010* replaced the *Trade Practices Act 1974* on 1 January 2011. APT Allgas is required to amend clause 14.4(c) as set out at amendment 12.16.

12.2.4.10 Confidentiality

Clause 15 sets out the obligations on the part of APT Allgas and users concerning confidentiality. Clause 18 sets out those terms and conditions that will survive on termination of an agreement. The confidentiality provisions are not included.

The AER considers that it is appropriate that confidentiality provisions should survive on termination or expiration of an agreement in order to protect confidential information. APT Allgas is required to amend clauses 15 and 18, as set out at amendments 12.17 and 12.18.

12.2.4.11 Termination

Clauses 18.1 and 18.2 set out the conditions under which APT Allgas and users may terminate an access agreement. Clause 18.1(a) states that APT Allgas may terminate an agreement if the user becomes insolvent.

The AER considers that it is reasonable for this provision to be reciprocal and that it is appropriate that users have the same right. APT Allgas is required to amend its terms and conditions to provide that a user may terminate an access agreement in the event that APT Allgas becomes insolvent, as set out at amendment 12.19.

Clause 18.4 allows APT Allgas to treat any costs reasonably incurred by APT Allgas in remedying a default as a liquidated debt payable by the user. Origin submitted that it should be clarified that the clause only applies if the user defaults.[10] The AER

[10] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 11.

considers it reasonable that users should pay APT Allgas's reasonably incurred costs in rectifying defaults by users. The AER considers that this is the likely intent of the clause. The AER does not consider, however, that users should pay APT Allgas's costs in remedying its own defaults. The AER requires APT Allgas to amend its terms and conditions to clarify clause 18.4, as set out at amendment 12.20.

Clause 18.5 provides that the termination rights and remedies available to APT Allgas are in addition to, and not in substitution for, any other rights or remedies available to APT Allgas under the access agreement, at law, in equity or otherwise.

The AER considers that it is appropriate that users have the same rights and remedies as APT Allgas on termination of an agreement. APT Allgas is required to amend clause 18.5 as set out at clause 12.21.

APT Allgas is required to make a similar amendment with respect to clause 22.3 (rights powers and remedies), as set out at amendment 12.22.

12.2.4.12 Conclusion

The AER considers that taken in aggregate the terms and conditions are weighted too much in favour of APT Allgas and do not comply with r. 100 of the NGR. To correct this imbalance the AER requires APT Allgas to amend a number of terms and conditions.

12.2.5 Amendments required to the access arrangement proposal and access arrangement information

Before the access arrangement proposal can be approved, APT Allgas must make the following amendments.

Amendment 12.1: amend clause 2.2 of the terms and conditions of the access arrangement proposal by inserting the words 'in accordance with clauses 2.1.1 and 2.1.2 of the access arrangement' after the words 'Demand Customer'.

Amendment 12.2: amend the terms and conditions of the access arrangement proposal by changing existing clause 3.3.7 to clause 3.3.7(a).

Amendment 12.3: amend the terms and conditions of the access arrangement proposal by inserting new clause 3.3.7(b):

'Nothing in this clause 3.3 prevents a new MDQ for a Demand Customer Delivery Point to be agreed on when the Demand Customer at the Demand Customer Delivery Point changes.'

Amendment 12.4: amend clause 3.3.8 and clause 3.3.9 of the terms and conditions of the access arrangement proposal by inserting the words 'for the same Demand Customer' between the words 'further request' and 'to APT Allgas'.

Amendment 12.5: amend the terms and conditions of the access arrangement proposal by inserting the words 'as soon as practicable' at the end of clause 3.3.6.

Amendment 12.6: amend clause 5.2.1 of the terms and conditions of the access arrangement proposal by inserting the words 'or in accordance with any pressure

range prescribed by law, if applicable,' between the words 'specified by APT Allgas' and 'from time to time'.

Amendment 12.7: amend the terms of conditions of the access arrangement proposal by inserting the words 'and the failure is not due to the negligent act or omission on the part of APT Allgas (or any officer, servant, agent, contractor or other person for whom APT Allgas is liable)' at the end of clause 5.2.2.

Amendment 12.8: amend clause 8.7 of the terms and conditions of the access arrangement proposal by inserting the words 'except for any claims that the User is required to pursue by law on behalf of a customer of the User' at the end of the paragraph that commences with the words 'The User may not claim'.

Amendment 12.9: amend the terms and conditions of the access arrangement proposal by deleting clause 9.1 and replacing it with the following:

'If a Cost Pass-through Event occurs that increases APT Allgas's costs, APT Allgas is entitled to recover an amount from the User, according to a mechanism reasonably determined by APT Allgas and approved by the AER which is equitable and is designed to ensure APT Allgas will not enjoy a windfall benefit. Any proposed increase must be material and must be approved by the AER in accordance with clause 4.5.3 of the Access Arrangement.'

Amendment 12.10: amend the terms and conditions of the access arrangement proposal by deleting clause 9.2 and replacing it with the following:

If a Cost Pass-through Event occurs that decreases APT Allgas's costs, APT Allgas shall pay the User an amount, according to a mechanism reasonably determined by APT Allgas and approved by the AER which is equitable and is designed to ensure APT Allgas will not enjoy a windfall benefit. Any proposed decrease must be material and must be approved by the AER in accordance with clause 4.5.3 of the Access Arrangement.

Amendment 12.11: amend the terms and conditions of the access arrangement proposal by deleting clause 10 and replacing it with the following:

'Each party will provide to the other party at no cost and in a timely manner whatever information, assistance and co-operation the other party might reasonably require from time to time in connection with this Access Agreement.

The User will procure the User's End Users, or Transmission Pipeline Operator, to provide to APT Allgas at no cost and in a timely manner whatever information, assistance and co-operation APT Allgas might reasonably require from time to time in connection with this Access Agreement.'

Amendment 12.12: amend the terms and conditions of the access arrangement proposal by deleting clause 13.1(b), clause 13.1(c)(i) and clause 13.1(c)(iii) of the terms and conditions of the access arrangement proposal.

Amendment 12.13: amend clause 13.2 of the terms and conditions of the access arrangement proposal by inserting the words 'arising from an event in relation to the

Network' between the words 'against the insurance policy' and 'maintained by the User' and deleting clause 13.2(c).

Amendment 12.14: amend the glossary in the access arrangement by including a definition of the term 'Consequential Loss', which appears in clause 14.1 of the terms and conditions of the access arrangement proposal, or alternatively revise the term 'Consequential Loss' to lower case 'consequential loss'.

Amendment 12.15: amend the terms and conditions of the access arrangement proposal by deleting clause 14.3 and replacing it with the following:

'Notwithstanding any other provision of this Access Agreement, any claim or claims by one party against the other party arising out of or in connection with this Access Agreement shall be limited to $100 000 in total in any one calendar Year during the Term.'

Amendment 12.16: amend clause 14.4(c) of the terms and conditions of the access arrangement proposal by deleting the words '*Trade Practices Act 1974*' and replacing them with the words '*Competition and Consumer Act 2010*'.

Amendment 12.17: amend the terms and conditions of the access arrangement proposal by inserting new clause 15.4:

'This Part 15 will survive the termination or expiration of the Access Agreement.'

Amendment 12.18: amend clause 18.3(a) of the terms and conditions of the access arrangement proposal by inserting the number '15' between the words 'Parts 8, 14' and 'and clause 18.6.

Amendment 12.19: amend clause 18.2 of the terms and conditions of the access arrangement proposal by inserting the words 'suffers an Insolvency Event or' between the words 'If APT Allgas' and 'defaults in the performance'.

Amendment 12.20: amend clause 18.4 of the terms and conditions of the access arrangement proposal by deleting the words 'this Part 18' and replacing them with the words 'clause 18.1'.

Amendment 12.21: amend clause 18.5 of the terms and conditions of the access arrangement proposal by deleting the word 'APT Allgas' and replacing it with the words 'each party'.

Amendment 12.22: amend the terms and conditions of the access arrangement proposal by deleting clause 22.3 and replacing it with the following:

'Each right, power and remedy of each party under this Access Agreement is in addition to any other right, power and remedy of each party under this Access Agreement or at law. The exercise by a party of any one right, power or remedy will not preclude the simultaneous or subsequent exercise of any other right, power or remedy.'

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. The AER notes that APT Allgas has proposed its requirements for changing receipt and delivery points under the heading of 'Capacity Trading'.[11] For consistency, the AER has also addressed the change of receipt and delivery points in this section.

12.3.1 Regulatory requirements

Under clause 48(f) of the NGR, capacity trading requirements are to be included in a full access arrangement. 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(3) and 105(2) 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.[12]

The terms and conditions for changing receipt and delivery points are to be included in a full access arrangement.[13] 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.[14]

12.3.2 Access arrangement proposal

Where users are registered participants under AEMO's Retail Market Procedures, APT Allgas proposed that capacity transfers should be subject to those procedures. Where users are not registered participants, APT Allgas proposed that capacity transfers should be subject to r. 105 and r. 106 of the NGR, and part 5 of the access arrangement.[15]

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11 Envestra, *Access arrangement information*, October 2010, p. 211.
12 NGR, r. 105(4).
13 NGR, r. 48.
14 NGR, r. 106.
15 APT Allgas, *Access arrangement proposal*, September 2010, p. 16.

APT Allgas proposed conditions under which users may make bare and non-bare transfers, change delivery and receipt points, and other procedures and conditions of transfers and assignments.[16] APT Allgas also set out the relevant definitions for chapter 5 in the access arrangement glossary.[17]

12.3.3 AER's considerations

The AER considers that APT Allgas's proposed capacity trading requirements are largely similar to those approved by the QCA in the earlier access arrangement.[18] However, the AER notes that APT Allgas's previous capacity trading requirements provided references to examples within the Code. For example, clause 5.2 of APT Allgas's earlier access arrangement stated that '[e]xamples of the basis by which Allgas could refuse a transfer are contained in section 3.11 of the Code'.[19] The AER notes that the NGR does not contain comparable examples, but considers such examples are important for end users' reference and understanding. Consequently the AER proposes to include an appropriate example within the access arrangement proposal. The AER does not consider that the inclusion of such examples will affect the operation of APT Allgas's proposed capacity trading requirements. Rather, the AER considers that examples will provide greater certainty to users, and therefore better promote the national gas objective outlined in s. 23 of the NGL.

12.3.4 Conclusion

The AER proposes not to approve APT Allgas's proposed capacity trading requirements. The AER considers amended requirements could better promote the national gas objective in s. 23 of the NGL.

12.3.5 Required amendments

Before the access arrangement proposal can be approved, APT Allgas must make the following amendments.

Amendment 12.23: amend section 5 of the access arrangement proposal as follows:

Insert the sentence 'An example might be, if APT Allgas would not receive at least the same amount of revenue it would have received before the change', at the end of the first paragraph in section 5.3.

Insert the sentence 'An example might be, if a reduction in the amount of the service provided to the initial delivery point will not result in a corresponding increase in APT Allgas's ability to provide that service to the alternative delivery point', at the end of the first paragraph in section 5.4.

12.4 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

16 APT Allgas, *Access arrangement proposal*, September 2010, p. 16.
17 APT Allgas, *Access Arrangement Proposal*, September 2010, p. 16.
18 QCA, *Draft decision- Revised access arrangements for gas distribution networks: Allgas Energy*, December 2005, p. 18.
19 APT Allgas, *Access arrangement proposal*, September 2010, p. 16.

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.

12.4.1 Regulatory requirements

Under r. 48 of the NER extension and expansion requirements are to be included in a full access arrangement.[20] 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.

12.4.2 Access arrangement proposal

APT Allgas's proposed extension and expansion policy is similar to that in APT Allgas's earlier access arrangement. Specifically, APT Allgas proposed that 'significant extensions' of the network should be notified to the AER before they come into operation, but only for the high pressure network rather than significant extensions for any part of the network as in their earlier access arrangement.[21] APT Allgas would indicate whether it considers the extension should be covered under the access arrangement, and why the extension is necessary. The AER would then have 20 business days to make a decision on APT Allgas's proposal. APT Allgas proposed that all other extensions and expansions will be covered by default.[22]

APT Allgas further note that all other extensions or expansions of the network, which are not considered 'significant extensions' should be covered by the access arrangement unless the AER and APT Allgas agree that they should not be covered.[23]

Where extensions and expansions are covered, APT Allgas proposed to offer services on that pipeline with no change in the reference tariffs. APT Allgas may levy a surcharge on users to recover non-conforming capital expenditure in accordance with the NGR.[24]

12.4.3 Submissions

AGL submitted that APT Allgas should provide a basis for the calculation of surcharges and a complete list of events which would trigger a surcharge. AGL also requested that surcharges be approved by the AER prior to being charged.[25]

12.4.4 AER's considerations

The AER does not accept APT Allgas'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

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20 NGR, r. 48(1)(g).
21 APT Allgas, *Access arrangement proposal*, September 2010, p.18.
22 APT Allgas, *Access arrangement proposal*, September 2010, p. 18.
23 APT Allgas, *Access arrangement proposal*, September 2010, p. 18
24 APT Allgas, *Access arrangement proposal*, September 2010, p. 19.
25 AGL, *Submission on APT Allgas's access arrangement proposal*, November 2010, p. 3.

where they also comply with applicable requirements and criteria under the NGL and the NGR. The AER considers that an amended version of APT Allgas's access arrangement proposal would better promote the national gas objective.[26]

Consistent with its previous decisions[27], the AER considers that all extensions to high pressure pipelines, rather than just 'significant' high pressure extensions as proposed by APT Allgas, should be assessed on a case-by-case basis for coverage. This is because high pressure pipelines have similar characteristics to transmission pipelines, and could be used either as viable bypass options to end users, or to support the existing network. The AER does not consider that any high pressure pipeline extensions should be covered by default. The AER considers this should allow for sufficient oversight of whether extension costs should be borne by reference service customers. The AER considers this will better promote the national gas objective than APT Allgas's approach, which could result in customers paying for investments in high pressure pipeline extensions to be used to bypass the network.

In contrast, the AER considers that low and medium pressure pipeline extensions are more likely to support the existing network than high pressure pipelines and should therefore be covered by default. If low or medium pressure pipeline extensions are not covered under the access arrangement, the AER considers that the service provider has scope to exercise monopoly power by charging above reference prices, with cross-subsidisation from the existing network. For these reasons, the AER considers that all low and medium pressure pipeline extensions should be covered by default.

Unlike extensions to the network, the AER considers that all expansions to the network should be covered by default. Network expansions involve the augmentation of pipeline capacity within the existing network, and are likely to be used largely by existing network customers. Relative to network extensions, they are much less likely to serve a new or isolated customer or group of customers as a bypass option. As such, it is appropriate that any network expansions are covered as reference services under the access arrangement.

The AER considers that APT Allgas 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.[28] The AER notes that APT Allgas's proposal contains no such provisions, and the AER requires APT Allgas to amend the access arrangement accordingly.

The AER notes AGL's submission on APT Allgas's requirements when proposing to levy a surcharge on uncovered high pressure pipeline extensions. Under r. 83(2) of the NGR, APT Allgas must notify the AER of proposed surcharges, which may be levied subject to the AER's approval. The AER will only approve a proposed surcharge subject to r. 83(4) of the NGR.

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26 NGL, s. 23.

27 For example: AER, *Jemena Gas Network draft decision*, February 2010, pp. 348–350; AER, *Actew AGL draft decision*, November 2009, pp. 185–186; AER, *Country Energy draft decision*, November 2009, pp. 140–141.

28 NGL, s. 23.

12.4.5 Conclusion

The AER proposes not to approve APT Allgas's proposed extensions and expansions policy proposed. The AER considers an amended policy would better promote the national gas objective in s. 23 of the NGL and better adhere to the pipeline coverage criteria in s. 15 of the NGL.

12.4.6 Required amendments

Before the access arrangement proposal can be approved, APT Allgas must make the following amendments.

Amendment 12.24: amend section 6.1 of the access arrangement proposal as follows:

If APT Allgas proposes a high pressure pipeline 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.

For the purposes of this section 6, a high pressure pipeline extension means a pipeline that exceeds one kilometre in length and is proposed to be built to a postcode area previously not serviced by reticulated gas.

A notification given by APT Allgas under this clause 6.1 must:

a) be in writing

b) state whether APT Allgas intends for the proposed high pressure pipeline extension to be covered by this Access Arrangement

c) describe the proposed high pressure pipeline extension and describe why the proposed Extension is being undertaken and

d) be given to the AER before the proposed high pressure pipeline extension comes into service.

APT Allgas is not required to notify the AER under this clause 6.1 to the extent that the cost of the proposed high pressure pipeline extension has already been included and approved by the AER in the calculation of Reference Tariffs.

After considering APT Allgas's application, and undertaking such consultation as the AER considers appropriate, the AER will inform APT Allgas of its decision on APT Allgas's proposed coverage approach for the high pressure 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 12.25: amend section 6.2 of the access arrangement proposal as follows:

Any extensions to and expansions of the capacity of the Network which are not high pressure pipeline extensions within the meaning of clause 6.1 will be treated as part of the Network and covered by this Access Arrangement.

All extensions of low or medium pressure pipelines and expansions of the capacity of the Network carried out by the Service Provider will be treated as covered under this Access Arrangement. No later than 20 Business Days following the expiration of its financial year, APT Allgas must notify the AER of all extensions of low or medium pressure pipelines and expansions of the capacity of the Network during that financial year, including all expansions commenced, in progress and completed. The notice must describe each extension and expansion and set out why this was necessary.

Amendment 12.26: insert the following new paragraph at the end of section 6.3 of the access arrangement proposal:

APT Allgas will notify the AER to seek approval of any proposed surcharge to be levied on users of incremental services, and designed to recover non-conforming capital expenditure or a specified portion of non-confirming capital expenditure (non-conforming capital expenditure which is recovered by means of a surcharge will not be rolled into the capital base). Surcharges will only be approved subject to rule 84(4) of the NGR.

12.5 Queuing requirements

Queuing can be used to determine access to a pipeline that is fully, or close to fully, utilised. Typically, new users will be able to be accommodated because, unlike transmission pipelines, distribution networks do not operate close to full capacity. If use at one point in the network is nearing capacity, augmentation of the network will normally be undertaken to meet the needs of prospective users.

12.5.1 Regulatory requirements

Queuing requirements are to be included in a full access arrangement only if the access arrangement is for a transmission pipeline or if the AER has notified the service provider to include queuing requirements.[29]

12.5.2 Access arrangement proposal

APT Allgas's access arrangement proposal did not include any references to queuing requirements.

12.5.3 AER's considerations

APT Allgas is not required to include queuing requirements in its access arrangement proposal as it operates a distribution pipeline and the AER has not required APT Allgas to include queuing requirements.[30] The AER notes that APT Allgas did not propose queuing requirements in the earlier access arrangement period and that the QCA did not require any to be included. The QCA came to this conclusion because it accepted APT Allgas's argument that queues were unlikely to form due to a lack of capacity in the network.[31]

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29 NGR, r. 103(1).
30 NGR, r. 103(1).
31 QCA, *Final Decision, Revised Access Arrangement for Gas Distribution Networks: Allgas Energy*, 2006, p. 22.

12.5.4 Conclusion

The AER proposes to approve APT Allgas's proposal not to include queuing requirements in its access arrangement proposal.

12.6 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, [32] or sooner in the event of certain triggers.[33] 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.

In general, a review submission date will fall four years after the current access arrangement took effect or the last revision commencement date, and a new revision commencement date will fall one year later.[34] 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 set out in r. 50 of the NGR. [35] 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.[36]

The review submission date may advance on that fixed in the access arrangement if a specified trigger event occurs.[37] 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.[38]

12.6.2 Access arrangement proposal

APT Allgas proposed a review submission date on or before 30 September 2015 and a revision commencement date of the later of 1 July 2016 and the date on which the AER's approval of the revisions to the access arrangement takes effect under the NGR.[39]

12.6.3 AER's analysis and consideration

The review submission date of 30 September 2015 proposed by APT Allgas is later than the 1 July 2015 date indicated by the general rule under r. 50(1) of the NGR. The AER considers that a 30 September 2015 review submission date would allow

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32 NGR, r. 50.
33 NGR, r. 51.
34 NGR, r. 50(1).
35 NGR, r. 50(2).
36 NGR, r. 50(4)
37 NGR, r. 51(1).
38 NGR, r. 51(3).
39 APT Allgas, *Access arrangement proposal*, September 2010, section 1.4.

significantly less time for the AER to make its decision on the access arrangements for APT Allgas compared to the 1 July 2015 date indicated by the general rule in the NGR. The AER considers that a truncated review process may reduce its ability to adequately consider the access arrangements, which could result in an outcome that is not consistent with the national gas objective. On the basis of this the AER rejects the 30 September 2015 review submission date proposed by APT Allgas.

As the revision commencement date proposed by APT Allgas is consistent with the general rule under r. 50(1)(b) of the NGR, the AER must accept it.

The AER notes that the retail energy and gas connections frameworks are expected to be introduced during the access arrangement period. These frameworks may impact on the terms and conditions of access for users and potential users, such as the credit support provisions proposed under the National Energy Customer Framework (NECF). In these circumstances, the AER considers that a trigger event should be included to enable the AER to review the approved terms and conditions of access for consistency with the arrangements proposed under these new frameworks.

12.6.4 Conclusion

The AER proposes not to accept APT Allgas's proposed review submission date. The AER considers an amended date could better promote the national gas objective in s. 23 of the NGL. The AER accepts the review commencement date of 1 July 2016 proposed by APT Allgas.

12.6.5 Required amendments

Before the access arrangement proposal can be approved, APT Allgas must make the following amendments.

Amendment 12.27: amend the access arrangement proposal to

1) delete the first paragraph of clause 1.4 and replace it with the following:

APT Allgas will submit revisions to this Access Arrangement to the AER on or before 1 July 2015.

2) include the following new clause 1.5:

The AER may require APT Allgas to revise its access arrangement for inconsistencies between the proposed terms and conditions and the NGL or NGR.

The revisions submission date stated in clause 1.4 of the access arrangement proposal will advance on the occurrence of a trigger event described below. For the purposes of this clause, a 'trigger event' occurs if:

(a) there is an amendment to the National Gas Law or the National Gas Rules, or the National Energy Retail Law or National Energy Retail Rules commence operation in Queensland; or

(b) the STTM does not operate as anticipated and the access arrangement does not effectively accommodate the STTM; and

(c) the AER provides APT Allgas with a notice stating that the circumstances described in (a) or (b) are significant. An amendment or the commencement in Queensland of the National Energy Retail Law or National Energy Retail Rules is significant if it affects reference tariffs. The new review submission date will be the date 6 months from the date of the notice provided by the AER under this clause.

(c) the AER provides APT Allgas with a notice stating that the circumstances described in (a) or (b) are significant. An amendment or the commencement in Queensland of the National Energy Retail Law or National Energy Retail Rules is significant if it affects reference tariffs. The new review submission date will be the date 6 months from the date of the notice provided by the AER under this clause.

A. Confidential averaging period

B. Actual cost of debt (confidential)

C. Detailed WACC issues

This appendix outlines the AER's consideration of detailed issues in relation to APT Allgas'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 in conjunction with chapter 5.

C.1 Overall rate of return

C.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.[1]

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.[2]

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

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1 Kevin Davis, *Cost of Equities – A Report for the AER,* 16 January 2011, p. 7.
2 Kevin Davis, *Cost of Equities – A Report for the AER,* 16 January 2011, p. 7.

contained in a market presentation released to the ASX on 26 October 2010 and is summarised as follows:

- 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.[3]

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[4] 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 C.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.

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3 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>

4 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 C.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	DEUT/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 C.2 presents analysis from Grant Samuel which shows listed infrastructure firms being traded at premiums significantly above regulated asset values.

Table C.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.

C.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.[5]

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 APT Allgas 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:[6]

- 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[7]
- 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

5 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 64.
6 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 64.
7 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 64 and Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network*, September 2010, p. 35.

Australian Composition index) "during a period that includes the effects of the current global financial crisis", which was 2.85 per cent[8]

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.

APT Allgas 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.[9] As a result, APT Allgas considers the 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.[10] 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. Arguments relating to the methodology in deriving the best estimate for different parameters used in determining the cost of equity and debt, although intuitively attractive do not necessarily mean that the outcome is unreasonable. The following sections of this chapter set out reasons for rejecting APT Allgas' proposed parameters (where relevant) and the AER's best estimates (and underlying methodologies).

C.1.3 Modigliani and Miller theorem

Consistent with Synergies' analysis, the AER considers the Modigliani and Miller approach can be used in a frictionless market 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.

Professor Kevin Davis and Associate Professor Handley (Handley) both caution the use of the Modigliani and Miller theorem to imply a relationship between the cost of

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8 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 64 and Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network*, September 2010, pp. 33–35.

9 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 63.

10 APT Allgas Energy Pty Limited, *Access Arrangement Submission*, September 2010, p. 63.

debt and equity.[11] Handley considers the Modigliani and Miller theorem in the presence of risk 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 firms 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.[12]

The AER considers the Modigliani and Miller proposition 2 can be used to demonstrate that the AER's weighted average cost of capital does not under compensate APT Allgas. According to the Modigliani and Miller proposition two, the weighted average cost of capital can be calculated as the return on equity of a firm with zero leverage. Removing the financial risk element from APT Allgas's proposed equity beta of 1.1 results in an asset beta estimate of 0.44. Therefore, using the parameters in APT Allgas's proposal, the return on equity on a zero is:

$$r_e = r_f + \beta * (MRP)$$

$$r_e = 5.07 + 0.44 * (6.5)$$

$$r_e = r_0 = 7.93$$

The WACC as implied by the Modigliani and Miller proposition 2 using APT Allgas's parameters is 7.93 per cent. This contrasts to the AER's weighted average cost of capital in this draft decision:

$$r_e = r_f + \beta * (MRP)$$

$$r_e = 5.68 + 0.8 * (6.0)$$

$$r_e = 10.48$$

$$r_o = r_e(\frac{E}{V}) + r_d(\frac{D}{V})$$

$$r_o(AER) = 10.48 * (0.4) + 9.61 * (0.6)$$

$$r_o(AER) = 9.96$$

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11 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.

12 John Hanley, *Peer Review of Draft Report by Davis on the Cost of Equity*, 18 January 2011, p. 9-10.

As is evident, the AER weighted average cost of capital (9.96 per cent) is significantly higher than the WACC implied by Modigliani and Miller proposition 2 using APT Allgas' parameters (7.93 per cent). The AER does not intend to set APT Allgas's WACC based on Modigliani and Miller proposition 2, however notes that this analysis demonstrates that the AER's return on capital does not under compensates APT Allgas.

C.2 Equity beta

The following section addresses issues raised by APT Allgas in regards to the beta estimate.

C.2.1 Systematic risk

APT Allgas submitted that a higher proportion of its total demand comes from industrial and commercial customers, in comparison to other distribution networks. Given that industrial and commercial demand will have a higher correlation with economic activity[13], APT considered that its network is exposed to more systematic risk in comparison to other distribution networks. However, the AER considers that APT Allgas may not be exposed to any more systematic risk than other distribution networks for the following reasons:

- a high proportion of demand customers (user that consume more than 10 TJ per annum) does not expose APT Allgas to any volatility related to overall economic activity, as demand users pay for gas based on capacity and not throughput. The users' capacity does not change in the short term as a result of economic activity, but does change in the longer term. However, in the longer term (or at least once every five years) this is risk is mitigated by the revisiting of forecast capacity use as part of the access arrangement review process

- a large proportion of the revenue that APT Allgas receives from volume customers (users that consume less than 10 TJ per annum) is derived from fixed charges. Residential customers are not expected to disconnect from the network as a result of changes in economic activity. Some commercial customers under the 10 TJ threshold may cease operations and disconnect during periods of sustained economic slowdown, however this only presents a risk to the extent any revenue impacts are not forecast at the time of the access review, and so may arise in the latter years of the access period where forecasts may be less accurate.

The AER considers that having a higher proportion of revenue derived from throughput charges may expose the service provider's revenue to more economic activity. For instance a negative shock to the economy may cause the actual throughput of customers to decrease, resulting in a service provider recovering less revenue from throughput charges. However, the AER considers that APT Allgas has not demonstrated that market volatility that causes revenue volatility directly effects share price volatility.

[13] Any risk arising from fluctuations in revenue due to economic activity (which affects the market portfolio) maybe systematic in nature.

Assuming that revenue volatility results in share price volatility, APT Allgas's revenue is exposed to the least amount of economic volatility out of all service providers assessed under the NGR. As demonstrated below, APT Allgas has the smallest proportion of revenue recovered from throughput charges.

Table C.3: Percentage of Revenue derived from throughput charges

	Percentage of throughput customers revenue that is derived from fixed (standing) charges	Percentage of Total Revenue that is derived Customers that pay for gas usage based on throughput charges	Percentage of Revenue potentially exposed to market volatility
Allgas (Brisbane)	38 %	68 %	0.68*(1-0.38) = 42 %
Jemena	19 %	93 %	0.93*(1-0.19) = 75 %
ActewAGL	12 %	96 %	0.96*(1-0.12) = 85 %
Country Energy	40 %	95 %	0.95*(1-0.40) = 57%

Source: All this data relates to the 2010-11 financial year. For APT Allgas this data was obtained from the annual tariff variations and all other firms this data was obtained from confidential regulatory models. This ignores the revenue received from ancillary and metering services.

APT Allgas submitted that gas is a 'fuel of choice' and therefore is exposed to competition from alternative energy sources, including electricity which is a fuel of necessity.[14] However, the AER considers that this competition does not expose APT Allgas to more systematic risk. For instance, this competition risk could be mitigated by an investor who holds both electricity and gas distribution stocks.

Furthermore, the AER is not satisfied that the following risks identified by APT Allgas are systematic in nature as they also can be mitigated through diversification of investments:

- competition is particular intense in the Queensland residential market, where gas has a relatively low penetration compared to other states[15]
- higher volume risk under the price cap[16]
- competition from solar and hear pump technology to heat water[17]
- demand and cost are not related

[14] APT Allgas Energy Pty Limited, *Access Arrangement Submission,* September 2010, p. 69.
[15] APT Allgas Energy Pty Limited, *Access Arrangement Submission,* September 2010, p. 69.
[16] APT Allgas Energy Pty Limited, *Access Arrangement Submission,* September 2010, p. 71. In the WACC review the AER considers there was no compelling evidence to suggest that the equity beta should differ based on the form of control (I.e. revenue vs. price cap). AER, *Final decision: WACC Review,* 1 May 2009, p. 341.
[17] APT Allgas Energy Pty Limited, *Access Arrangement Submission,* September 2010, p. 71.

- in Queensland, less than 1 per cent of dwelling used gas for heating[18]
- higher penetration of revenue cycle air conditioners
- only 12.5 per cent of dwelling utilise main gas, which is notably lower than the other states[19]
- one customer accounts for 14 per cent of total forecast demand for the demand tariff class, and the top five customers account for close to 30 per cent of forecast demand.

Some of the issues above are not uncommon for other gas distribution service providers and therefore to do not justify a departure from a beta of 0.8 which the AER has determined to be appropriate for these businesses.

APT Allgas submitted that the recent drought has resulted in a permanent reduction in water usage (due to the introduction of the efficient shower heads) and therefore resulted in lower demand for gas hot water services. However, to the extent that a permanent reduction in demand has been taken into account in the forecasts underlying the access arrangement mitigates the risk of a service provider not recovering its building block revenue. Only an unexpected movement in demand will affect systematic risk.

C.2.2 Data issues

Synergies submitted that paucity of relevant and reliable data has precluded it from being able to draw any robust conclusions regarding APT Allgas' equity beta based on an updated empirical analysis.[20] However 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

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18 Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network,* September 2010, p. 57.

19 Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network,* September 2010, p. 55.

20 Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network,* September 2010, p. 3.

- Hasting Diversified Utilities Fund
- 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.[21] To the address the issue of short trading histories of Australian comparable companies, the AER estimated the beta using weekly observations (as opposed to monthly observations).[22]

Synergies 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.[23] 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.[24] 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.[25] 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.[26]

C.2.3 Regulatory consistency

Synergies noted that differences in market power have previously influenced regulatory decisions in relation to beta.[27] Synergies submitted that the ACCC determined a higher asset beta for ARTC Interstate Decision (0.65) in contrast to the Hunter Valley (0.5), due to ARTC having less market power as it is exposed to intermodal competition. As a result, Synergies submits that APT Allgas is exposed to more competition from alternative energy sources in contrast to other distribution networks and therefore APT Allgas should receive a higher beta estimate in contrast

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21 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).

22 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).

23 Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network,* September 2010, p. 45.

24 AER, Final decision: *WACC Review*, 1 May 2009, p. 293.

25 AER, Final decision: Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters, 1 May 2009, p. 298 (AER, Final decision: WACC Review, 1 May 2009).

26 AER, Final decision: Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters, 1 May 2009, p. 307 (AER, Final decision: WACC Review, 1 May 2009).

27 Synergies Economic Consulting, *Estimating a WACC for the APT Allgas Distribution Network,* September 2010, p. 69.

to other distribution businesses. The AER considers that APT Allgas is not exposed to intermodal because the cost of switching energy fuel sources is significant in commercial and industrial production and in some cases not possible. Consequently, the AER considers that the high switching costs for a gas user implies that APT Allgas would have a higher degree of market power. Further, intermodal competition is not the only reason why the ARTC beta estimate in the Interstate Decision is larger than in the Hunter Valley Decision. For instance, the ACCC considered that ARTC's risk was mitigated by a number of factors including:

- the use of long term contracts which provide certainty to ARTC on a significant proportion of its revenue, and consequently that ability to insulate itself from both volume and asset stranding risks
- the steady demand for coal over the medium term
- the use of loss capitalisation in Pricing zone 3
- short asset lives.[28]

In addition to this, APT Allgas submits that regulatory consistency requires some weight be given to the equity beta of 1.1 that applied in the earlier access arrangement period (under the QCA). The AER considers substantial new empirical analysis has been undertaken since the QCA's final decision, which provides a more up to date estimation of the equity beta for prevailing market conditions as required by the NGR.[29] The NGR requires the AER to determine a rate of return that reflects prevailing market conditions.

C.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 10 years and a BBB+ credit rating. The 10 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.[30]

APT Allgas's regulatory proposal did not explicitly discuss the benchmark characteristics on which to base estimates of the DRP under the NGR.[31] Implicit in APT Allgas's proposal, however, is that the DRP should reflect debt issued for a period of 10 years, with a BBB+ credit rating.

The methodology proposed by APT Allgas for estimating the DRP is infeasible since CBASpectrum has ceased publication of its 10 year, BBB+ fair value yield curve. APT Allgas more recently submitted to the AER that:

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28 ACCC, *Position Paper in relation to the Australian Rail Track Corporation's proposed Hunter Valley Rail Network Access Undertaking*, 21 December 2010, pp. 105–112.

29 For particular details, see AER, Final decision: WACC review, May 2009 and NGR, r. 87(1).

30 While the SORI has no status under the NGR, it was intended to provide guidance to the gas sector.

31 NGR, r. 87(2).

> …the Fair Value Curves developed by Bloomberg remain the best source of information on which the AER can base its assessment of the cost of debt "commensurate with prevailing conditions in the market for funds".[32]

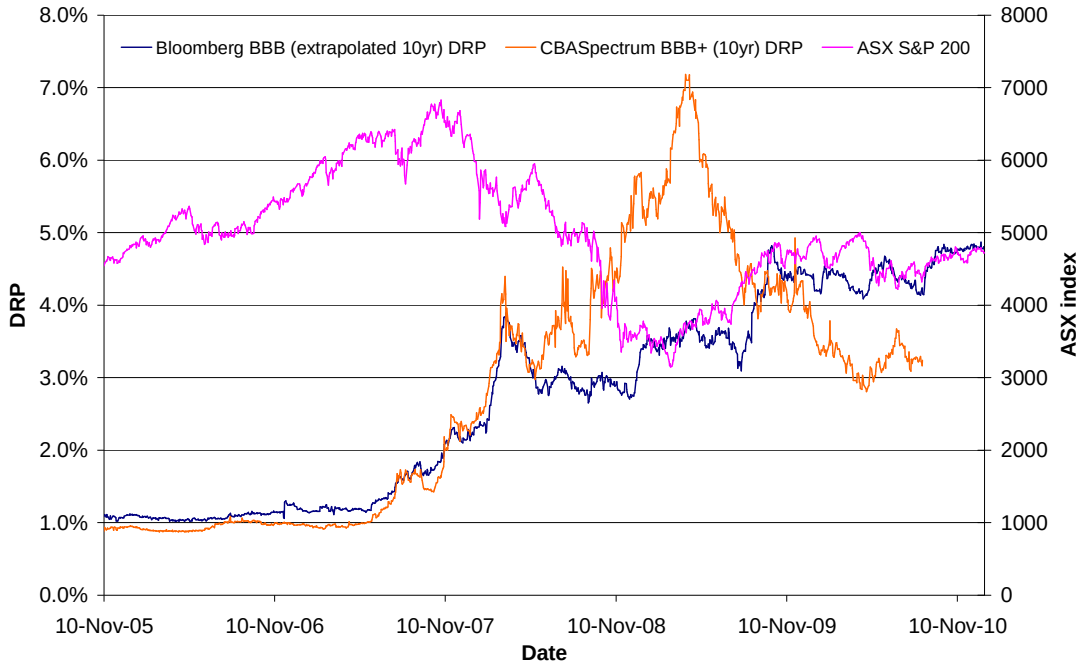
Accordingly, the AER has considered APT Allgas's more recent proposal to rely on Bloomberg as a sole estimate, as well as examining alternative sources of information for estimating the DRP. In particular, the AER has considered the relevance of the 10 year, BBB rated bond issued by the APA Group and the A- rated Stockland bond as alternative sources of information when setting the benchmark cost of debt.

C.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 7 years.[33] 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 C.1.

Figure C.1: Changes in debt risk premia in comparison to the ASX S&P 200



Source: Bloomberg, CBASpectrum, RBA, AER analysis.

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32 APT Pipeline Limited, *Submission in response to AER notice under section 42(2)(a) of the National Gas Law*, 14 January 2011.

33 AER, *Victorian electricity distribution network service providers, Distribution determination 2011–2015, Final decision*, October 2010, pp. 505–506.

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.[34] 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 history, including periods spanning the GFC. In contrast, 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 10 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 7 years. Specifically, in July 2010 the Australian Pipeline Trust—the financing arm for the APA Group—announced the issuance of a new 10 year, BBB rated corporate bond (APT bond) with a yield to maturity well below that indicated by Bloomberg's fair value estimates. Similarly, property firm Stockland recently issued a 10-year, A-rated bond (Stockland bond) with a yield that is currently over 100 basis points below the extrapolated Bloomberg fair value curve.

The paucity of corporate bonds with credit ratings at or close to BBB+ with maturities greater than 5 years currently trading in the market has been acknowledged by both APT Allgas and the Tribunal.[35] 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 C.2, along with Bloomberg's fair value estimates for 5 and 7 years, and an extrapolation to 10 years (using the AER's extrapolation method, discussed below).

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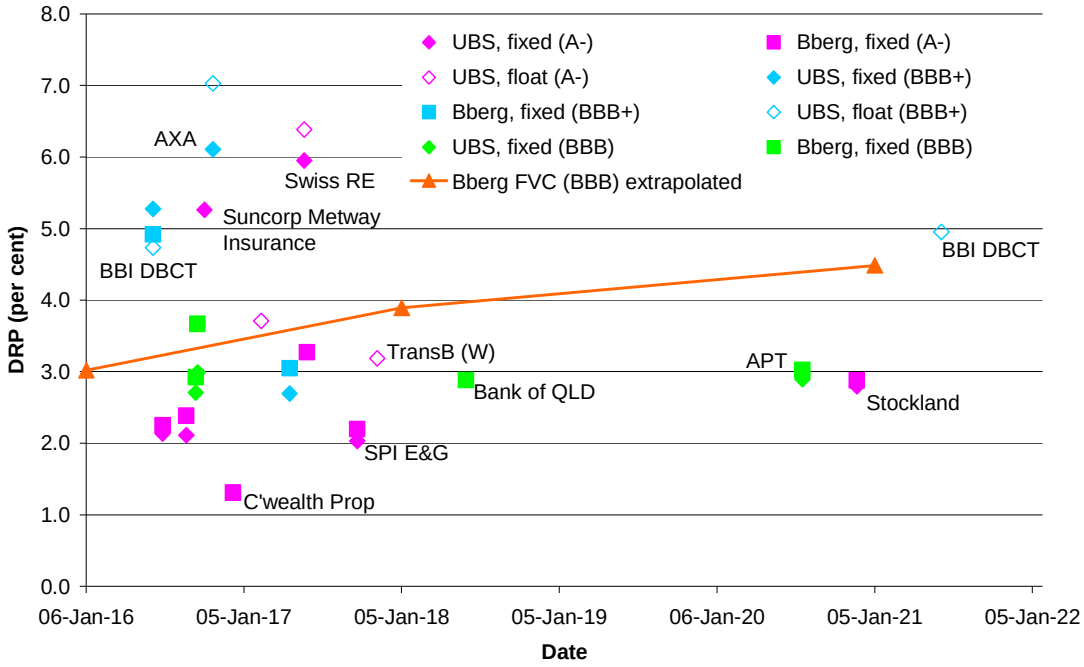
[34] In practice, the interaction between debt and equity markets is more complicated than this, but generally, heightened financial risk translates to lower share prices and a higher DRP.

[35] APT Allgas, *Access Arrangement submission, effective 01 July 2011–30 June 2016*, October 2010, pp. 65–66; Australian Competition Tribunal, *Application by ActewAGL Distribution [2010] ACompT4*, 17 September 2010, paragraph 75, 77.

Figure C.2: Australian corporate bonds with maturities greater than 5 years and credit ratings ranging from BBB to A-



Source: Bloomberg, UBS, AER analysis.

Of the bonds plotted in this figure, the three of immediate interest are the APT, Stockland and DBCT bonds, which are considered in turn below.

C.3.2 APA Group bond

The yields on the APT bond are likely to provide a close match to those of the benchmark corporate bond.[36] Specifically, the AER considers that the APT bond—with a BBB credit rating and 10 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 overcompensate APT Allgas with respect to the BBB+ rated benchmark cost of debt.

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 likelihood of default is the single most important factor in our assessment of creditworthiness.[37]

[36] AER, *Draft approach for measuring the debt risk premium*, September 2010, p. 3.
[37] Standard and Poor's, Guide to credit rating essentials, 2010, p. 4.

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.

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 rating, Oakvale suggested that factors such as industry (for example, infrastructure versus financial institution bonds) and liquidity are relevant.[38] 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.[39]

In this context, the AER regards 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 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 (with respect 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 would be expected to produce a rate of return that is commensurate with the risks involved in providing reference services in the case of APT Allgas.

C.3.3 Stockland bond

In November 2010, Stockland issued a 10 year, A- rated corporate bond. Similar to the APT bond, the tenor and credit rating of this issuance are comparable to the AER's benchmark. However the nature of Stockland's assets and the industry in which it operates differ markedly to that of APT Allgas.

This notwithstanding, the AER considers that the yield on the Stockland bond provides a point of reference to assess the reasonableness of Bloomberg's BBB fair value estimates and also of the APT bond. In this regard, the yield on the Stockland bond is over 100 basis points below the extrapolated 10-year Bloomberg fair value estimate, while only 10 basis points from the APT bond. The difference from the extrapolated Bloomberg fair value estimate (using the AER's extrapolation method) is likely to be substantially driven by its lower credit rating, however the size of this difference is such that other factors are likely to be relevant. Where APT Allgas's method of extrapolation is applied, this difference is greater still.

Overall, while the Stockland and APT bonds provide only two points of reference, they both indicate that the extrapolated Bloomberg fair value may not be representative of longer dated, low rated bonds.

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38 Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011, pp. 2–3.

39 John Handley, *Comments of the CEG Report: Estimating the 10 year BBB+ cost of debt*, 11 February 2011, p. 6.

C.3.4 Dalrymple Bay Coal Terminal (DBCT) bond

The characteristics of the DBCT bond maturing in 2021 match the benchmark 10 year, BBB+ corporate bond. The AER, however, has previously expressed concerns over the reliability of this bond in comparative analysis.[40] 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.[41]

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.[42] 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.[43] 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 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.

In summary, the lack of corporate bonds with BBB+ ratings and maturities of 10 years makes it difficult to reliability 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 Stockland bond. 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 10 year, BBB fair value derived from Bloomberg and of the APT bond when setting the DRP.

C.3.5 Actual cost of debt

Given the limited data available in setting the DRP, the AER considers it prudent to consider the actual costs of debt currently incurred by APT Allgas. This information has enabled the AER to better consider the appropriateness of applying its DRP. APT Allgas's actual cost of debt reaffirms that:

- the benchmark cost of debt set by the AER using Bloomberg and the APT bond is consist with providing APT Allgas with a reasonable opportunity to recover at least the efficient costs (section 24(2) of the NGL)

- the benchmark cost of debt set by the AER is consistent with setting APT Allgas's reference tariff at a level that allows a return commensurate with the regulatory and commercial risks involved in providing the reference service (section 24(2))

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40 AER, *Final decision*, October 2010, pp. 505–506.
41 PwC, *Debt risk premium over the approved averaging period beginning 2 August 2010*, October 2010, pp. 8–10.
42 Application by ActewAGL Distribution [2010] ACompT4, p. 22, paragraph 70.
43 Oakvale Capital, *Report on the cost of debt during the averaging period: The impact of callable bonds*, February 2011, pp. 20–22.

- the benchmark cost of debt set by the AER is appropriate for APT Allgas having regard to the economic costs and risks of under and over investment (section 24(2)).

To ascertain APT Allgas's actual cost of debt, the AER issued a notice under section 42 of the NGL requesting information on debt instruments with remaining maturities of greater than 5 years.[44] This information is presented in the confidential appendix B. In supplying this information, APT Allgas submitted that:[45]

- information on the actual cost of debt is not relevant to determining a benchmark cost of debt as it is neither a benchmark or reflective of prevailing conditions
- as some debt instruments are not traded it is difficult to ascertain their current market price, and subsequently, their yields
- information published by independent and respected providers, such as Bloomberg, provided the best information on prevailing conditions
- as the regulatory regime, reflected in rule 87(2) of the NGR, encourages businesses to outperform benchmarks, basing the benchmark cost of debt on actual costs undermines this incentive.

The AER has not based the DRP on the actual cost data provided by APT Allgas. The AER considers that prevailing conditions have been reflected in the use of data on the APT bond and Bloomberg fair value estimates over the indicative averaging period used for this decision. This data will be updated to reflect prevailing market conditions at the time of the final decision.

Similarly, the AER has maintained the incentive for APT Allgas to achieve efficiencies in its cost of capital by using a benchmark rather than referencing its actual cost of debt.

While the AER recognises that it has obtained historic information, a certain proportion of its debt portfolio was issued during the GFC. Hence, the AER expects APT Allgas's overall cost of debt to decrease as this debt is retired and new, cheaper debt is raised or refinanced over the forthcoming access arrangement period.

C.3.6 Extrapolation method

Since Bloomberg only publishes BBB fair value estimates to 7 years, the AER and service providers have been required to extrapolate this curve to a 10 year tenor for the purposes of setting the DRP. The AER has most recently considered that in lieu of Bloomberg publishing a 10 year, BBB rated fair value estimate, the spread on Bloomberg's AAA rated estimates from 7 to 10 years should be added to Bloomberg's 7 year, BBB rated fair value curve.[46] The AER considers that this extrapolation

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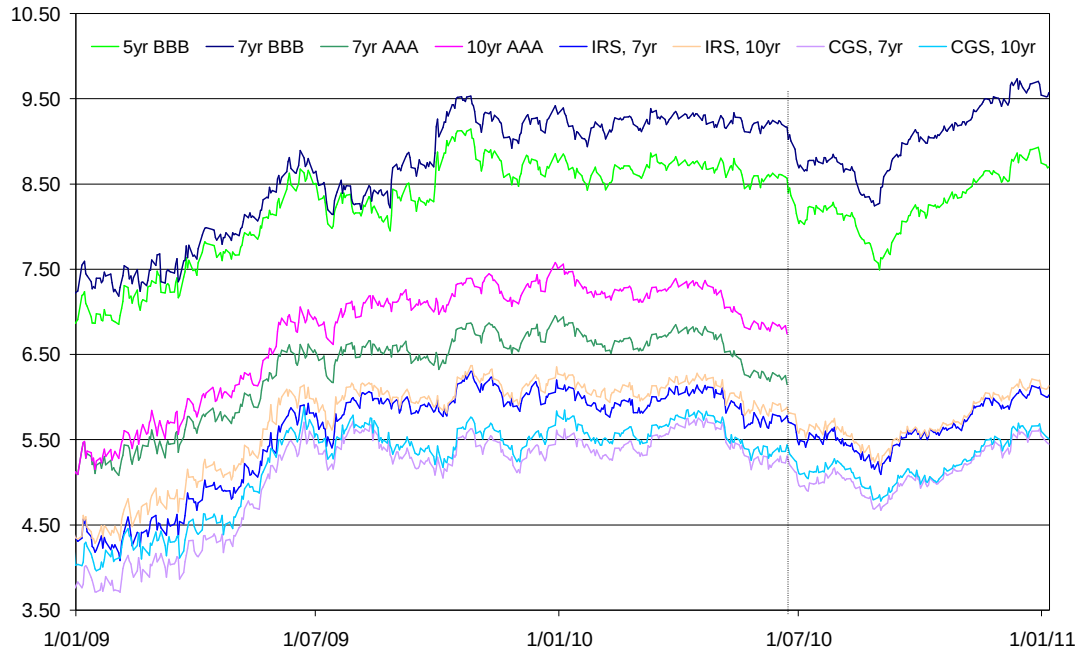
44 AER, *AER notice under section 42(2)(a) of the National Gas Law*, December 2010.
45 APT Pipeline Limited, *Submission in response to AER notice under section 42(2)(a) of the National Gas Law*, 14 January 2010.
46 AER, *Final decision*, October 2010, pp. 510–511.

approach provides a better estimate of the 10 year, BBB rated yields than an approach based on linear extrapolation, as proposed by APT Allgas.

Specifically, the AER has previously demonstrated that a linear extrapolation of Bloomberg's BBB curve (using the change in spread between the 5 and 7 year estimates, and projecting this to 10 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 10 year BBB fair value estimates.[47] Further, a linear extrapolation of Bloomberg's 7 year, BBB fair value curve results in a 10 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 7 or 10 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 7 to 10 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 7 year, BBB rated fair value curve. This approach implicitly assumes that the spread between Bloomberg's 7 and 10 year, AAA fair value estimates has remained relatively constant over the period since June 2010. Figure C.3, below, supports this assumption.

Figure C.3: Yield curve movements



Source: Bloomberg, AER analysis.

Notably, Bloomberg's 7 year, BBB rated fair value curve has historically moved consistently with Bloomberg's 7 and 10 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

[47] AER, *Final decision*, October 2010, p. 490.

infer that had Bloomberg continued to publish 7 and 10 year, AAA rated fair value curves, these curves would likely have continued to move in line with those examples provided above. It follows that the spread between Bloomberg's 7 and 10 year, AAA rated curves reflects as reasonable an extrapolation method now as it did in June 2010.

For these reasons, the AER considers that APT Allgas' extrapolation methodology does not provide for a rate of return on capital that is reasonably consistent with benchmark levels of efficiency.[48] In contrast, the AER considers its extrapolation approach provides the best estimate possible in the circumstances of APT Allgas. Substitution of APT Allgas' method with the AER's approach results in a reduction in the DRP of approximately 35 basis points (based on the indicative averaging period ending 6 January 2011).

C.3.7 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 upon 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, complete reliance can be placed on Bloomberg's fair value estimates.

The AER has also considered other information which it considers relevant to setting the benchmark BBB+ 10 year bond yield. In particular, the AER considers that the credit rating, maturity and similarities between the operations of the APA Group and APT Allgas 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 doubts over) and the Stockland bond.

The AER therefore considers that an average of Bloomberg's 10 year, BBB fair estimate curve and the APA Group bond represents the best DRP estimate possible in the circumstances of APT Allgas.[49] Specifically, 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 3.93 per cent over the indicative averaging period ending 6 January 2011.

The AER also considers that this DRP is appropriate to apply in the case of APT Allgas, having regard to its expected actual cost of debt.

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[48] Consistent with NGR, r. 87(2).
[49] Consistent with NGR, r. 74(2)(b).

C.4 Market risk premium

C.4.1 Time periods for historical excess returns

Table C.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.

The starting points for each sample period in table C.4 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.[50]

- 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 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.[51]

[50] Brailsford, Handley and Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and Finance, vol. 48, pp. 78–79.

[51] Officer and Bishop appear to incorporate this adjustment in their long-term estimates. See Officer and Bishop, *Comments on the AER draft distribution determination for Victorian electricity distribution network service providers*, July 2010, p. 21.

- The period 1958 to 2010 provides a smaller number of observations, but it avoids the issues associated with data prior to 1958.

C.4.2 The difference between arithmetic and geometric means

Table C.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.

Table C.5outlines 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.[52] The geometric mean return is zero.[53] 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.[54] Therefore, for a 10 year horizon the arithmetic mean of

[52] A fall of 20 per cent plus a rise of 25 per cent, divided by 2.
[53] The square root of (1–0.20)*(1+0.25), minus 1.
[54] Handley, An estimate of the historical equity risk premium for the period 1883 to 2010, January 2011, pp. 3–4.

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 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.[55] 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.

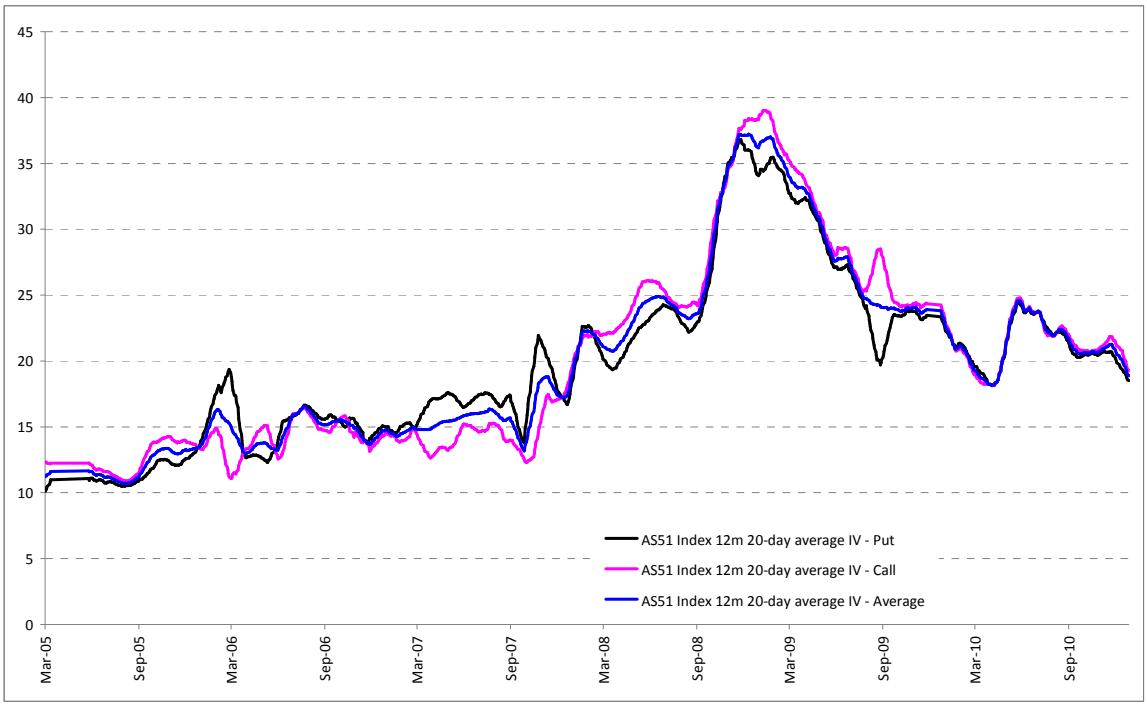
In the WACC review, the AER noted that Blume, as well as Dimson, Marsh and Staunton have proposed methods that could be used to calculate an expected MRP using both arithmetic and geometric means.[56] The results from these weighted averages produce different results, which makes it harder to determine 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.

C.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 C.4 and C.5.

[55] AER, Final decision, Review of weighted average cost of capital parameters, 1 May 2010, p. 199.
[56] AER, Final decision, Review of weighted average cost of capital parameters, 1 May 2010, pp. 198–199.

Figure C.4: Implied volatility from option prices as reported by Bloomberg



Source: Bloomberg, AER analysis.

Figure C.5: 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. [57]

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.[58] In a previous report, Officer and Bishop advocated using a long term estimate due to the variability in data on market returns.[59] 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 C.3 and C.4 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.[60] 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% 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.'[61] 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".[62] Other research also suggests that option implied volatility is an unreliable estimator of the expected MRP.

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

58 The AER has noted 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.

59 Officer and Bishop, *Market risk premium, A review paper*, August 2008, pp. 36–37.

60 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.

61 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.

62 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:[63]

> …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.[64]

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.[65]

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63 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.

64 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.

65 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.

D. AER's consideration of proposed non-tariff terms and conditions and issues raised in submissions

Matter	Description of terms and conditions, submissions and AER's consideration	Amendment required
Determination of customer (clause 2.2)	Clause 2.2[1] provides that APT Allgas will determine from time to time whether an end user is a volume customer or demand customer. The determination is binding on the user. Clauses 2.1.1 and 2.1.2 of the access arrangement itself set out the criteria for determining whether an end user is entitled to the demand customer service or the volume customer service.[2] Origin submitted that clause 2.2 should stipulate that the determination will be made according to the principles outlined in clauses 2.1.1 and 2.1.2 of the access arrangement.[3] The AER agrees with Origin's submission. The AER considers that clause 2.2 is ambiguous and may be construed as giving APT Allgas absolute discretion. APT Allgas is required to amend its access arrangement to the effect that clause 2.2 is subject to clauses 2.1.1 and 2.1.2 of the access arrangement.	Amendment 12.1.
MDQ overruns (clause 3.2)	APT Allgas proposed that it will adjust nominated MDQ if actual MDQ exceeds nominated MDQ twice in a 12 month period (a change from the current terms and conditions that specify two billing periods in a contract year).	None.

1 All references to 'clauses' in this appendix relate to the terms and conditions of APT Allgas's access arrangement proposal, unless otherwise stated.
2 APT Allgas, *Access arrangement proposal*, October 2010, pp. 5–6.
3 Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 9.

	APT Allgas submitted that the changes clarify and simplify the provisions.[4] AGL submitted that it acknowledges the proposed changes to clause 3.2. However, AGL submitted that what constitutes the 12 month period should be clarified.[5] The AER considers that clause 3.2 is clear and no amendment is required.	
Reduction in MDQ (clause 3.3)	APT Allgas proposed new terms and conditions for requests for reductions in MDQ. APT Allgas submitted that the new provisions formalise arrangements by which users can request a reduction in MDQ and include relevant considerations for APT Allgas when it receives such a request.[6] AGL submitted that the development of a protocol to communicate information should not occur within an access arrangement. Instead, it should be referred to the appropriate reference group within the industry, specifically the AEMO. This would allow the adoption of agreed industry practice to ensure consistency among participants and across jurisdictions.[7] The AER considers that formalising these arrangements should result in timely reduction in MDQ and free up spare capacity for prospective users. In the absence of any industry wide arrangements, the AER considers that it is appropriate for an access arrangement to contain such terms and conditions.	Amendments 12.2 12.3, 12.4, and 12.5.

4 APT Allgas, *Access arrangement submission*, September 2010, p. 13.
5 AGL, *APT Allgas's access arrangement*, November 2010, p. 5.
6 APT Allgas, *Access arrangement submission*, September 2010, p. 13.
7 AGL, *APT Allgas's access arrangement*, November 2010, p. 6.
8 AGL, *Envestra's Qld gas network access arrangement*, November 2010, pp. 7–11.
9 Envestra, *Response to AGL's submission*, December 2010, pp. 7–8.
10 AER, *Draft Decision, Envestra access arrangement proposal for the Qld gas network*, February 2011, s. 13.2.4.1.
11 AER, *Draft Decision, Envestra access arrangement proposal for the Qld gas network*, February 2011, s. 13.2.4.1; AER, *Draft Decision, Envestra access arrangement proposal for the SA gas network*, February 2011, s. 13.2.4.1.

	A condition before a user may request a reduction in MDQ is that for a period of not less than 12 months the user's customer must not have taken delivery of gas in excess of its MDQ (clause 3.3.1(b)). In a submission relating to Envestra's Queensland network concerning a similar provision, AGL submitted that is unfair for new customers to have to wait for up to 12 months before the MDQ is reduced.[8] In a response to AGL's submission, Envestra submitted new customers do not have to wait 12 months for a reduction as they are unrelated to existing customers.[9] In that matter the AER requires Envestra to amend its terms and conditions to clarify that is the case.[10] The AER requires APT Allgas to make a similar amendment to its terms and conditions. Clause 3.3.6 provides that upon request APT Allgas must give a user an explanation of its decision to reject a request for a reduction in MDQ. However, clause 3.3.6 does not stipulate a time period for APT Allgas to respond. The AER considers that it is appropriate for APT Allgas to respond in a timely manner. APT Allgas is required to amend its terms and conditions to the effect that if will provide an explanation as soon as practicable. The AER requires Envestra to make a similar amendment with respect to its Queensland and South Australian networks in response to an issue raised by AGL in its submission.[11]	
Quantity received (clause 3.7)	Clause 3.7 provides that APT Allgas may determine the quantity of gas delivered through a receipt point for a user on a reasonable basis, and the determination binds the user.	None.

Metering (clause 4)	Clause 4 provides that APT Allgas is required to correct previous meter readings. Origin submitted that the terms and conditions should contain mechanisms that would allow a user to query the quantity of gas delivered and the accuracy of meters.[12] The AER notes that nothing in the proposed terms and conditions precludes a user from making such inquiries of APT Allgas. The AER does not require an amendment. As discussed below, the AER requires an amendment to clause 10 (information and assistance) so that APT Allgas is obliged to give a user whatever information and assistance the user reasonably requires.	
Delivery point pressures: APT Allgas's obligation (clause 5.2.1) Failure to comply (5.2.2)	Clause 5.2.1 requires APT Allgas to deliver gas at a minimum pressure of 1.125 kPa, but always within the pressure range specified by APT Allgas from time to time. The AER considers that APT Allgas's ability to specify the delivery pressure range should be subject to any pressure range prescribed by law. APT Allgas is required to amend its terms and conditions accordingly. Clause 5.2.2 sets out the conditions under which APT Allgas is excused from liability for a breach of clause 5.2.1. This includes due to 'the technical, practical and physical limitations of the Network' (clause 5.2.2(a)). Origin submitted that clause 5.2.2(a) should be deleted. Origin submitted that it is so broad that it is difficult to see under what circumstances APT Allgas could be held to its obligations under clause 5.2.1. Origin further submitted that the physical and practical limitations of the network are factors that should be taken into account when determining delivery point pressures.[13] The AER notes Origin's submission. However, the AER considers that clause 5.2.2 reflects matters	Amendment 12.6 and 12.7.

[12] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 9.
[13] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, pp. 9–10.

	that are outside APT Allgas's control. Regarding Origin's submission concerning the technical, practical and physical limitations of the network, the AER agrees that these are factors that should be taken into account when APT Allgas determines delivery pressures under clause 5.2.1. However, the AER requires an amendment to clarify that APT Allgas is not relieved of its obligations if the failure to deliver gas within the range of pressures is due to its negligence.	
Invoicing (clause 8.3)	Clause 8.3 sets out the provisions by which APT Allgas will invoice users. Clause 8.3(c) provides that an invoice will describe each item with sufficient information to enable a user to reconcile 'Charges' at an individual level. The definition of 'Charges' has been revised to now include non-reference services.[14] AGL submitted that it sought justification for expanding the term to include non-reference services.[15] The AER considers that the definition of the word 'Charges' has been expanded to reflect that an invoice may specify amounts due in respect of both reference services and non-reference services. The AER does not require an amendment.	None.
Incorrect tax invoices (clause 8.7)	Clause 8.7 provides that a user may not claim from APT Allgas any amount overcharged if more than 12 months has elapsed since the date of the invoice. Origin submitted that an exception should be made if Origin is required by law to pursue a claim on behalf of a customer, as there is no time limitation in these circumstances.[16] The AER agrees with Origin's submission. The AER considers it appropriate that any claims that a	Amendment 12.8.

[14] APT Allgas, *Access arrangement proposal*, October 2010, Appendix A, p. 2.
[15] AGL, *APT Allgas's access arrangement*, November 2010, p. 6.
[16] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 10.

	user is required to pursue by law should not be subject to the 12 month time period. APT Allgas is required to amend clause 21 to exempt any claims a user is required to make by law on behalf of a customer.	
Cost pass through (clause 9)	APT Allgas proposed revisions to the terms and conditions associated with an increase or decrease in the costs of an obligation imposed on APT Allgas (a cost pass through event). Clause 9.1 provides that APT Allgas is entitled to recover any increase in costs according to a mechanism reasonably determined by APT Allgas ,which is equitable and ensures that APT Allgas does not enjoy a windfall gain. Any proposed increase must be material and approved by the AER in accordance with the provisions set out in the access arrangement (clause 4.5.3).[17] APT Allgas submitted that the revisions were made so that they are consistent with the proposed revisions to cost pass through provisions in the access arrangement proposal.[18] The AER received no submissions on this matter. The AER requires APT Allgas to amend clause 9 to clarify that the reference to a cost pass through event is consistent with the definition contained in the access arrangement.[19] The AER also requires an amendment to clarify that the mechanism reasonably determined by APT Allgas must be approved by the AER.	Amendments 12.9 and 12.10.
Information and assistance (clause 10)	Clause 10 provides that a user is required to provide APT Allgas with whatever information, assistance and cooperation APT Allgas might reasonably require. Further, a user must obtain from its end users and the transmission pipeline operator whatever information, assistance and	Amendment 12.11.

[17] APT Allgas, *Access arrangement proposal*, September 2010, p. 20.
[18] APT Allgas, *Access arrangement submission*, September 2010, p. 13.
[19] APT Allgas, *Access arrangement proposal*, September 2010, p. 20, appendix A, p. 3.

	cooperation APT Allgas reasonably requires from those entities. Origin submitted that this clause means that network users could be obliged to pay the network for any assistance but cannot request payment in return. Origin submitted that clause 10 should be reciprocal or removed.[20] The AER agrees with Origin's submission and considers that it reasonable for these arrangements to be reciprocal. The AER considers it appropriate that either party should provide the other party with whatever information and assistance it reasonable requires. APT Allgas is required to amend its terms and conditions accordingly.	
Insurance (clause 13)	Clause 13.1(a) requires users to take out certain insurance policies. Clause 13.1(b) requires users to obtain APT Allgas' approval of the terms of each insurance policy. Clause 13.1(c) requires users to give APT Allgas (whenever reasonably requested by APT Allgas); copies of insurance policies (clause 13.1(c)(i)), certificates of currency (clause 13.1(c)(ii)), and any other information APT Allgas requests (clause 13.1(c)(iii)). Clause 13.2 requires users to consult with APT Allgas on insurance claims. Origin submitted that the proposed clauses concerning insurance are unworkable in practice. Origin submitted that its insurance policies are confidential. Further, Origin submitted that timing would prevent it obtaining APT Allgas's approval of the terms of its insurance policies. Origin submitted that APT Allgas should not have to be consulted over claims that do not relate to APT Allgas. Origin also submitted that it is unrealistic to require a user to consult with APT Allgas about any claims as the terms of settlement are confidential.[21]	Amendments 12.12 and 12.13.

[20] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 10.
[21] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, pp. 10–11.

	The AER agrees with Origin's submission. The AER does not consider that it is reasonable for users to be required to provide copies of insurance policies to APT Allgas. In addition, the AER does not consider users should be required to seek APT Allgas's approval of the terms of insurance policies. The AER also considers that clause 13.1(c)(iii) is too broad. The AER requires APT Allgas to delete clauses 13.1(b), 13.1(c)(i) and 13.1(c)(iii) of its proposed terms and conditions. The AER also requires APT Allgas to amend clause 13.2 to clarify that the claim must relate to APT Allgas's network only and to delete clause 13.2(c).	
Consequential loss (clause 14.1)	Clause 14.1 provides the neither APT Allgas nor the user is liable for consequential loss. Origin submitted that the intention of clause 14.1 is that neither party is liable for consequential loss, but this should be clarified.[22] The AER considers that clause 14.1 is clear that neither party is liable for consequential loss. The AER does not require an amendment. Origin submitted that clause 14.1 is contradictory as it commences with the words 'Notwithstanding anything in this Access Agreement' and ends with the words 'except as provided for elsewhere in the Access Arrangement'.[23] The AER does not consider that clause 14.1 is contradictory. Origin may be confusing the access arrangement with an access agreement between APT Allgas and a user. The AER does not require an amendment. Origin also submitted that the term 'Consequential Loss' appears to be a defined term but is not	Amendment 12.14.

[22] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 10.
[23] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 10.

	actually defined.[24] It appears that it is APT Allgas's intention that the term 'Consequential Loss' should be a defined term. APT Allgas is required to update its glossary accordingly, or alternatively revise the term 'Consequential Loss' to lower case 'consequential loss'.	
Warranties, indemnities and limitation of liability Limit of liability (clause 14.3) Implied warranties (clause 14.4)	Clause 14.3 provides that any claim by a user against APT Allgas is limited to $100,000 in any one year. The AER considers that this arrangement should be reciprocal and it is appropriate that any claim by ATP Allgas against a user should also be limited. The AER requires amendments to similar arrangements for Envestra's Queensland and South Australian networks, in response to a submission from Origin.[25] Clause 14.4(c) provides that nothing in an access agreement excludes or limits the application of any provision of any statute (including the Trade Practices Act 1974). The AER considers that clause 14.4(c) needs to be updated to reflect that the *Competition and Consumer Act 2010* replaced the *Trade Practices Act 1974* on 1 January 2011. APT Allgas is required to amend clause 14.4(c) accordingly.	Amendments 12.15 and 12.16.
Confidentiality (clause 15)	Clause 15 sets out the obligations on the part of APT Allgas and users concerning confidentiality. Clause 18 sets out the terms and conditions that will survive on termination of an agreement. The confidentiality provisions are not included.	Amendments 12.17 and 12.18.

[24] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 10.
[25] AER, *Draft Decision, Envestra access arrangement proposal for the Qld gas network*, February 2011, s. 13.2.4.2; AER, *Draft Decision, Envestra access arrangement proposal for the SA gas network*, February 2011, s. 13.2.4.2
[26] Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 11.

	Origin submitted that confidentiality obligations should outlive an access agreement in order to protect confidential information.[26] The AER agrees with Origin's submission and considers that it is appropriate that confidentiality provisions should survive on termination or expiration of an agreement. APT Allgas is required to amend clauses 15 and 18 accordingly.	
Disputed tax invoices (clause 16)	Clause 16 sets out the procedures that the parties must follow to settle any disputes. AGL submitted that the source document associated with clause 16 should be included.[27] It is not clear to the AER what AGL means when it submits that the source document should be included. The AER does not require an amendment.	None.
Termination (clause 18)	Clauses 18.1 and 18.2 set out the conditions under which APT Allgas and users may terminate an access agreement. Clause 18.1(a) states that APT Allgas may terminate an agreement if the user becomes insolvent. The AER considers that it is reasonable for this provision to be reciprocal and that it is appropriate that users have the same right. APT Allgas is required to amend its terms and conditions to provide that a user may terminate an access agreement in the event that APT Allgas becomes insolvent. The AER requires amendments to similar arrangements for Envestra's Queensland and South Australian networks, in response to a submission from Origin.[28] Clause 18.4 allows APT Allgas to treat any costs reasonably incurred by APT Allgas in remedying a	Amendments 12.19 to 12.22.

[27] AGL, *APT Allgas's access arrangement*, November 2010, p. 6.
[28] AER, *Draft Decision, Envestra access arrangement proposal for the Qld gas network*, February 2011, s. 13.2.4.2; AER, *Draft Decision, Envestra access arrangement proposal for the SA gas network*, February 2011, s. 13.2.4.2.

	default as a liquidated debt payable by the user. Origin submitted that it should be clarified that the clause only applies if the user defaults.[29] The AER agrees with Origin's submission. The AER considers that it is unreasonable for users to pay APT Allgas's costs in remedying its own defaults. The AER also considers that the likely intent of the provision is that it only refers to defaults by users. The AER requires an amendment to clarify this. Clause 18.5 provides that the termination rights and remedies available to APT Allgas are in addition to, and not in substitution for, any other rights or remedies available to APT Allgas under the access agreement, at law, in equity or otherwise. Origin submitted that this qualification should be reciprocal.[30] The AER agrees with Origin's submission. The AER considers that it is appropriate that users have the same rights and remedies as APT Allgas on termination of an agreement. APT Allgas is required to amend its terms and conditions accordingly. APT Allgas is required to make a similar amendment to clause 22.3 (rights, powers and remedies).	
Force majeure (clause 19)	Clause 19 sets out the relevant provisions relating to force majeure events. AGL submitted that it is unsure whether the terms 'Affected obligation', 'Precluded Extent' and 'Actual Delay' are defined. AGL further submitted that the term 'Precluded Extent' should be changed back to the current term 'Precluded Event'.[31]	None.

29 Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 11.
30 Origin, *Envestra (Qld) and APT Allgas access arrangement proposals*, November 2010, p. 11.
31 AGL, *APT Allgas's access arrangement*, November 2010, p. 7.

	The AER does not agree with AGL's submission. The AER considers that the intent and meaning of the terms are clear from the text. The AER also considers that the term 'Precluded Extent' is more appropriate than 'Precluded Event'. The AER does not require an amendment.	
Notices (clause 21)	Clause 21.1 sets out the form that notices must take. Clause 21.2 sets out when a notice is taken to have been received. AGL submitted that email is excluded under clause 21.(1). AGL further submitted that if email is adopted as an acceptable form of notice, then clause 21.2 also needs to be revised.[32] Clause 21.1 allows the parties to agree on a form of communication other than as set out in clause 21.1 In light of this, the AER does not require an amendment.	None.

[32] AGL, *APT Allgas's access arrangement*, November 2010, p. 8.

E. Annual reporting requirements

In this draft decision, the AER has indicated that APT Allgas will have to report certain information on an annual basis. This information is generally required to ensure compliance with an approved tariff variation mechanism, or to otherwise monitor APT Allgas's performance and compliance with this decision.

This appendix provides a summary of the information APT Allgas must report to the AER during the access arrangement period. The AER anticipates that this information would be reported annually, as part of an annual tariff variation proposal. During the access arrangement period, the AER may also require information to be provided in response to a regulatory information instrument. This appendix is not exhaustive of the information the AER may seek through any regulatory information instrument.

Information contained in the table below has been drawn from the chapters in this draft decision.

Table E.1: Annual reporting requirements

Reference	Reporting requirement	Purpose
Annual reference tariff variations – chapter 11	For each year, on or around 15 April, notify the AER in respect of any reference tariff variations such that variations occur on 1 July, and include: ▪ the proposed variation to reference tariffs ▪ an explanation and details of how the proposed variations have been calculated ▪ an independent statement to support the gas quantity inputs in the tariff variation formula. The statement should be independently audited or verified and the quantity input will reflect the most recent actual annual quantities available at the time of tariff variation assessment. The actual quantity should be provided as four quarters of gas quantity data reconciling to an annual total quantity of gas.	Annual tariff variation approval.

F. 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 APT Allgas's proposal to determine debt raising costs using the AER's standard method.[1] 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 APT Allgas proposed this allowance be rolled into the overall WACC, the AER implements a separate opex line item to preserve transparency.

F.1 Access arrangement proposal

APT Allgas proposed to follow the AER's standard method for the determination of debt raising costs,[2] which is based on a 2004 report to the ACCC by the Allen Consulting Group (ACG).[3] APT Allgas proposed a debt raising cost unit rate of 10.8 bppa,[4] which was based on the allowance set for Jemena Gas Networks in an earlier AER decision document.[5] This unit rate was then incorporated into the overall cost of debt used as an input to the WACC, such that APT Allgas proposed to receive debt raising costs as an implicit component of its return on capital.

F.2 AER's consideration

The AER accepts the APT Allgas 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. 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 F.1 shows the build up of debt raising costs, after updating inputs to the model (including the appropriate level of debt raising costs).

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1 APT Allgas, *Access arrangement submission*, September 2010, pp. 75–76. 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.

2 For example, see AER, *Final decision, South Australia distribution determination 2010–11 to 2014–15*, May 2010, pp. 124–133, 371–384 (Appendix J: Debt raising completion method); AER, *Final decision - appendices, Victorian electricity distribution network service providers, Distribution determination 2011–2015*, pp. 474–501 (Appendix N: Debt raising costs);

3 ACG, *Debt and Equity Raising Transaction Costs, Final Report to the Australian Competition and Consumer Commission*, December 2004.

4 APT Allgas, *Access arrangement submission*, September 2010, pp. 75–76.

5 AER, *Final Decision, Jemena Gas Networks access arrangement proposal for the NSW gas network*, June 2010, p. 278.

Table F.1: Indicative direct debt raising costs with a nominal vanilla WACC of 9.96 per cent

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	7.31	7.31	7.31	7.31	7.31
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/$1million per annum	0.04	0.04	0.04	0.04	0.04
Total	**Basis points per annum**	10.9	9.9	9.6	9.4	9.3

Source: ACG, Bloomberg, AER analysis.

APT Allgas has an opening capital base of $411 million, which leads to a notional debt component of $247 million at the assumed gearing ratio (60 per cent). This amount of debt requires one standard size ($250m) bond issue. After adjusting for the indicative discount rate (9.96 per cent) the appropriate unit rate estimate is 10.9 bppa. This leads to the debt raising allowance set out in table F.2:

Table F.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
APT Allgas proposal	10.8 bppa	Implicit in WACC	(no explicit allowance)					
AER draft decision	**10.9 bppa**	**Opex line item**	**0.27**	**0.27**	**0.28**	**0.28**	**0.28**	**1.38**

Source: APT Allgas, *Access arrangement information - PTRM*, AER analysis
Note: Numbers may not add due to rounding

F.3 Conclusion

The AER approves the method proposed by APT Allgas for determining the debt raising cost unit rate, but does not approve the form of this allowance (as an implicit component of the WACC). The AER considers that a separate debt raising costs line item, as shown in table F.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 APT Allgas to amend its debt raising costs as outlined in amendment F.1.

F.4 Required amendments

Amendment F.1: make all necessary amendments to the access arrangement proposal and access arrangement information in order to be consistent with table F.2.

G. Submissions

The AER received submissions on APT Allgas's proposal from the following entities:

- AGL Energy Limited
- Origin Energy Retail Ltd

Glossary

AAG	access arrangement guideline
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACIL Tasman	ACIL Tasman Pty Ltd
AEMO	Australian Energy Market Operator
AGL	AGL Energy Ltd
APT Allgas	APT Allgas Energy Pty Limited
ASX	Australian Stock Exchange
BOM	Bureau of Meteorology
bppa	basis points per annum
CAPM	Capital Asset Pricing Model
CDI	CHESS Depository Interest
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CGS	Commonwealth Government Securities
CPRS	carbon pollution reduction scheme
DBCT	Dalrymple Bay Coal Terminal
DEEDI	Department of Economic Development and Innovation
DNSP	distribution network service provider
DRP	debt risk premium
EBA	enterprise bargaining agreement
EBSS	efficiency benefit sharing scheme

EGW	electricity, gas and water
EMRF	Energy Market Reform Forum
Envestra	Envestra Ltd
FFM	Fama–French three factor model
FRC	full retail contestability
FTE	full time employee
GDP	gross domestic product
GFC	global financial crisis
GJ	gigajoule (1 000 000 000 joules)
HIA	Housing Industry Association
IRR	internal rate of return
IT	information technology
KPI	key performance indicator
LME	London Metal Exchange
LRMC	long run marginal cost
MDQ	maximum daily quantity
MHQ	maximum hourly quantity
MRP	market risk premium
NECF	National Energy Customer Framework
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industry Research
NPV	net present value
NYMEX	New York Mercantile Exchange
OESR	Office of Economic and Statistical Research

Origin	Origin Energy Retail Ltd
O&M	operating and maintenance
ORER	Office of the Renewable Energy Regulator
PJ	petajoules (equal to 1000 terajoules)
PTRM	post-taxation revenue model
QLD	Queensland
RBA	Reserve Bank of Australia
REES	Residential Energy Efficiency Scheme
RFM	roll forward model
RIN	regulatory information notice
ROLR	retailer of last resort
SA	South Australia
SEO	seasoned equity offering
SFG	Strategic Finance Group Consulting
STTM	short-term trading market
TJ	terajoules (equal to 1000 gigajoules)
Tribunal	Australian Competition Tribunal
UAG	unaccounted for gas
WACC	weighted average cost of capital
WAPC	weighted average price cap
Wilson Cook	Wilson Cook & Co Limited