



**Final Decision**

**Revised Access Arrangement for Gas  
Distribution Networks:  
Allgas Energy**

*May 2006*

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## **PREAMBLE**

### **Background to Final Decision**

#### *Code Requirements*

Allgas' current access arrangement expires on 30 June 2006. In accordance with the Gas Code, Allgas submitted a revised access arrangement on 30 September 2005 for approval by the Authority.

The Code sets out the process by which the revised access arrangement is to be approved. The Authority released its Draft Decision in December 2005. The period for submissions on the Draft Decision closed on 27 February 2006. The Authority received four submissions.

In response to the Authority's Draft Decision, Allgas submitted a further revised access arrangement for approval by the Authority. This version of Allgas' access arrangement included many of the amendments required by the Authority in its Draft Decision.

#### *Authority's Approach*

The Authority re-engaged consultants to provide advice on key issues raised in submissions from stakeholders. The Authority received final reports from its consultants in April and May 2006.

In assessing Allgas' revised access arrangement and preparing this Final Decision, the Authority has considered the submissions from stakeholders, the advice from the consultants and the public interest.

The Authority's Final Decision is to not approve Allgas' revised access arrangement in its current form. In order for Allgas' revised access arrangement to be approved, Allgas is required to make a number of amendments as detailed in this Final Decision.

In accordance with sections 2.38(b) and 2.40 of the Code, Allgas is required to resubmit its revised access arrangement and access-arrangement information, amended in accordance with this Final Decision, by 5 June 2006. Before deciding whether or not to approve them, the Authority will assess the revised access arrangement and the access arrangement information against the amendments required in this Final Decision.

### **Final Decision**

#### *Asset Base*

The Authority has determined the value of the opening capital base, as at 1 July 2006, for Allgas to be \$303.2 million. In doing so, the Authority has included almost all capital expenditure undertaken by Allgas during the current regulatory period.

For the next regulatory period, the Authority has accepted \$143.5 million in capital expenditure for Allgas.

This compares with an opening asset base, as at 1 July 2006, proposed by Allgas of \$303.0 million and forecast capital expenditure of \$162.1 million

#### *Operating Costs*

The Authority has accepted \$57.7 million of operating costs for Allgas over the next regulatory period. This compares with the \$59.6 million of operating costs proposed by Allgas.

### *Rate of Return*

The Authority's decision on the rate of return remains unchanged from its Draft Decision. In its Draft Decision, the Authority estimated the WACC for Allgas to be 8.75 per cent. That result was the same as the rate proposed by Allgas. While the Authority did not endorse the methodology used by Allgas to arrive at its proposed WACC, the Authority decided to accept the rate of return proposed by Allgas. Consequently, Allgas will receive a return of 8.75 per cent on its capital base.

### *Summary*

Overall, the Authority has forecast that Allgas will require total revenue of \$230.0 million over the next five years.

Based on this revenue requirement, prices for Allgas' smaller volume customers are likely to change by CPI each year, while for Allgas' large demand customers prices are likely to vary by CPI-0.2 per cent each year.

These price paths apply to the weighted averages of tariffs within customer groups. As a result, price changes to individual customers may vary somewhat about those marks. The Authority has required that prices to individual volume customers not increase by more than CPI+3 per cent in any year. However, in recognition of the ongoing problem of a lack of cost reflectivity in prices to some customers, particularly small volume customers (typically domestic consumers), the Authority will consider price increases above this side constraint where Allgas can demonstrate that such an increase will assist in moving tariffs to more cost reflective levels.

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## GLOSSARY

<b>Access Arrangement</b>	an arrangement for access to a Covered Pipeline that has been approved by the Relevant Regulator
<b>Access Arrangement Information</b>	information provided by a Service Provider to the Relevant Regulator pursuant to section 2.2, 2.3, 2.9, 2.28 or 2.30 of the Code
<b>Access Arrangement Period</b>	the period from when an Access Arrangement or revisions to an Access Arrangement take effect (by virtue of a decision pursuant to section 2 of the Code) until the next Revisions Commencement Date
<b>Additional Staff</b>	servants, consultants, independent consultants and agents of a Service Provider who are not Marketing Staff and who the Regulator regards as indirectly involved in the sale or advertising of Services
<b>Additional Revenue Policy</b>	has the meaning given in section 3.28(d) of the Code (that is, in relation to approval by the Relevant Regulator of a Tender Approval Request for a new pipeline, certain tenders may be excluded if they do not include a policy on whether additional revenue resulting from transportation of gas exceeding a certain volume is to be retained by the Service Provider or returned in whole or in part to Users in the form of lower charges or some other form)
<b>Anticipated Incremental Revenue</b>	the present value (calculated at the Rate of Return) of the reasonably anticipated future revenue from the sale of Services at the Prevailing Tariffs which would not have been generated without the Incremental Capacity, minus the present value (calculated at the Rate of Return) of the best reasonable forecast of the increase in Non-capital Costs directly attributable to the sale of those Services
<b>Arbitrator</b>	has the meaning given in the Gas Pipelines Access Law (that is, the Relevant Regulator or a person appointed by the Relevant Regulator to conduct an arbitration relating to an access dispute)
<b>Bare Transfer</b>	has the meaning given in section 3.10 of the Code (that is, a Trading Policy provided as part of an Access Arrangement must comply with a number of principles, including that the terms of a contract with a service provider must not be altered as a result of a transfer or assignment to another party)
<b>Bypass</b>	the construction of a pipeline to avoid the existing Transmission or Distribution system (or part thereof)
<b>Capacity</b>	the measure of the potential of a Covered Pipeline as currently configured to deliver a particular Service between a Receipt Point and a Delivery Point at a point in time
<b>Capacity Management Policy</b>	has the meaning given in section 3.7 of the Code (that is, a statement in an Access Arrangement that a Covered Pipeline is either a Contract Carriage Pipeline or a Market Carriage Pipeline)
<b>Capital Base</b>	has the meaning given in section 8.4 of the Code (that is, the value of the capital assets that form the Covered Pipeline)
<b>Capital Contribution</b>	has the meaning given in section 8.23 of the Code (that is, a Charge which exceeds the Charge that would apply under a Reference Tariff for a Reference Service (or, in relation to another Service, under the Equivalent Tariff) in respect of the funding of a new facility)

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<b>Charge</b>	for a Service, means the amount that is payable by a User to the Service Provider for that Service
<b>City Gate</b>	transition point from high pressure transmission pipelines to distribution network
<b>Code</b>	National Third Party Access Code for Natural Gas Pipeline Systems as changed from time to time in accordance with the Gas Pipelines Access Law
<b>Code Registrar</b>	has the meaning given in the Gas Pipelines Access Law (that is, a person appointed to or acting in the position of Code Registrar appointed under the <i>Gas Pipelines Access (South Australia) Act 1997</i> of South Australia)
<b>Confidential Information</b>	<p>information that is by its nature confidential or is known by the Service Provider to be confidential and includes:</p> <ul style="list-style-type: none"> <li>(a) any information relating to the financial position of a User or Prospective User and, in particular, includes information relating to the assets or liabilities of the User or Prospective User and any other matter that affects or may affect the financial position or reputation of the User or Prospective User;</li> <li>(b) information relating to the internal management and structure of the User or Prospective User or the personnel, policies and strategies of a User or Prospective User;</li> <li>(c) information of a User or Prospective User to which the Service Provider has access, other than information referred to in paragraphs (a) and (b), that has any actual or potential commercial value to the User or Prospective User or to the person or corporation which supplied that information; and</li> <li>(d) any information in the Service Provider's possession relating to the User's or Prospective User's customers or suppliers and like information</li> </ul>
<b>Contracted Capacity</b>	that part of the Capacity which has been reserved by a User or Users pursuant to a contract entered into with the Service Provider
<b>Contract Carriage</b>	<p>is a system of managing third party access whereby:</p> <ul style="list-style-type: none"> <li>(a) the Service Provider normally manages its ability to provide Services primarily by requiring Users to use no more than the quantity of Service specified in a contract;</li> <li>(b) Users normally are required to enter into a contract that specifies a quantity of Service;</li> <li>(c) charges for use of a Service normally are based at least in part upon the quantity of Service specified in a contract; and</li> <li>(d) a User normally has the right to trade its right to obtain a Service to another User</li> </ul>
<b>Core Provisions</b>	in the Code, sections 2.24, 3.1 to 3.4 (inclusive), 3.28, 3.33, 3.34, 4.1 to 4.4 (inclusive), 6.15, 6.18, 8.1 and 9.1 to 9.4 (inclusive) and this definition of Core Provisions
<b>Coverage/ Covered</b>	in relation to a Pipeline or part of a Pipeline, that that Pipeline or part of a Pipeline is subject to the provisions of the Code pursuant to sections 1.1, 1.13, 1.20 or 1.21 of the Code

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<b>Covered Pipeline</b>	subject to sections 2.3 and 2.4 of the Code, the whole or a particular part of a Pipeline which is Covered and any extension to, or expansion of the Capacity of, that Covered Pipeline which is to be treated as part of the Covered Pipeline in accordance with the Extensions/Expansions Policy contained in the Access Arrangement for that Covered Pipeline and any expansion of that Covered Pipeline required to be installed under section 6.22 of the Code
<b>Delivery Point</b>	the point or points within the Covered Pipeline at which the custody of Natural Gas is transferred from a Service Provider to a User
<b>Depreciated Actual Cost</b>	the value that would result from taking the actual capital cost of a Covered Pipeline and subtracting the accumulated depreciation for those assets charged to Users
<b>Depreciated Optimised Replacement Cost (DORC)</b>	the minimum cost of replacing or replicating the service potential embodied in a pipeline with modern equipment and in the most efficient way practicable, from an engineering perspective, given service requirements, and the age and condition of existing assets
<b>Depreciation</b>	in any year and on any asset or group of assets, the amount calculated according to the Depreciation Schedule for that year and for that asset or group of assets
<b>Depreciation Schedule</b>	has the meaning given in section 8.32 of the Code (that is, the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the Covered Pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of determining a Reference Tariff)
<b>Developable Capacity</b>	the difference between (actual) Capacity and the Capacity which would be available if additions of plant and/or pipeline were made, but does not include any extension of the geographic range of a Covered Pipeline
<b>Distribution</b>	the transportation of gas over a combination of high pressure and low pressure pipelines from a City Gate to various customers' usage points
<b>End User</b>	means a person who: <ul style="list-style-type: none"> <li>(a) acquires or proposes to acquire Natural Gas from a User; or</li> <li>(b) proposes to acquire Natural Gas from a Prospective User</li> </ul>
<b>End User Information</b>	in relation to an End User, information obtained by a Service Provider, or by its servants, consultants, independent contractors or agents, in the course of conducting its business that relates to the actual Natural Gas usage and usage patterns of that End User, but does not include any such information provided by a User or Prospective User to the Service Provider
<b>Equivalent Tariff</b>	in relation to a Service that is not a Reference Service, the Tariff that it is reasonably likely would have been set as the Reference Tariff had the Service been a Reference Service
<b>Exclusivity Right</b>	a contractual right that by its terms either: <ul style="list-style-type: none"> <li>(a) expressly prevents a Service Provider supplying Services to persons who are not parties to the contract; or</li> <li>(b) expressly places a limitation on the Service Provider's ability to supply Services to persons who are not parties to the contract,</li> </ul> but does not include a User's contractual right to obtain a certain volume of Services

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<b>Extensions/ Expansions Policy</b>	a policy that is required to be in an Access Arrangement which sets out a method for determining whether extension or expansion to a Covered Pipeline is or is not to be treated as part of the Covered Pipeline for the purposes of the Code
<b>Final Approval Request</b>	has the meaning given in section 3.29 of the Code (that is, in relation to the Relevant Regulator approving a Tender Approval Request, the person who conducted the tender process may apply in writing to the Relevant Regulator for final approval)
<b>Fixed Period</b>	has the meaning given in section 8.47 of the Code (that is, the period during which a Fixed Principle may not be changed)
<b>Fixed Principle</b>	has the meaning given in section 8.47 of the Code (that is, a Reference Tariff Policy may provide that certain principles are fixed for a specified period and not subject to change without the agreement of the Service Provider when a Service Provider submits reviews to an Access Arrangement)
<b>Gas Pipelines Access Law</b>	in relation to Queensland, means: <ul style="list-style-type: none"> <li>(a) the provisions referred to in paragraph (a) of the definition of “Gas Pipelines Access Law” in section 3(1) of the South Australian Act, as applying as a law of that Scheme Participant; and</li> <li>(b) Regulations in force under Part 3 of the South Australian Act, as applying as a law of that Scheme Participant</li> </ul>
<b>Incentive Mechanism</b>	has the meaning given in section 8.44 of the Code (that is, the Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism that permits the Service Provider to retain all, or a share of, any returns from the sale of a Reference Service during an Access Arrangement Period or during a period commencing at the start of an Access Arrangement and including two or more Access Arrangement periods approved by the Relevant Regulator that exceeds the level of returns expected at the beginning of the Access Arrangement Period, particularly where the additional returns are attributable, at least in part, to the efforts of the Service Provider)
<b>Incremental Capacity</b>	the increase in Capacity attributable to a New Facility
<b>Incremental Revenue</b>	revenue generated by sales of Incremental Capacity
<b>Incremental User</b>	a User that could not have been serviced without the addition of the Incremental Capacity
<b>Information Package</b>	the Information Package described in section 5.1 of the Code (that is, which includes the Access Arrangement, Access Arrangement Information, details of available capacity, information regarding the layout of the pipelines, and how to make an access request)
<b>Interruptible Supply</b>	a Service which does not guarantee to supply gas at requested levels
<b>Jurisdictional Area</b>	has the meaning given in the Gas Pipelines Access Law
<b>Load Factor</b>	the ratio between average yearly load and peak daily load
<b>Local Appeals Body</b>	in the case of Queensland, the Queensland Gas Appeals Tribunal
<b>Local Minister</b>	the local Minister within the legislation for that scheme participant (in the case of Queensland, the Minister for Mines and Energy)

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<b>Local Regulator</b>	in the case of Queensland, the Queensland Competition Authority
<b>Market Carriage</b>	<p>a system of managing third party access whereby:</p> <ul style="list-style-type: none"> <li>(a) the Service Provider does not normally manage its ability to provide Services primarily by requiring Users to use no more than the quantity of Service specified in a contract;</li> <li>(b) Users are normally not required to enter a contract that specifies a quantity of Service;</li> <li>(c) charges for use of Services are normally based on actual usage of Services; and</li> <li>(d) a User normally does not have a right to trade its right to obtain a Service to another User</li> </ul>
<b>Market Variable Element</b>	a factor that has a value assumed in the calculation of a Reference Tariff, where the value of that factor will vary with changing market conditions during the Access Arrangement Period or in future Access Arrangement Periods, and includes the sales or forecast sales of Services, any index used to estimate the general price level, real interest rates, Non-capital Cost and any costs in the nature of capital costs
<b>Marketable Parcel</b>	<p>all or part of a User's Contracted Capacity which the User reasonably expects:</p> <ul style="list-style-type: none"> <li>(a) that the User will not utilise and does not require for technical or safety reasons;</li> <li>(b) to be of a size and type capable of being sold to another User or to a Prospective User; and</li> <li>(c) to be able to sell without incurring transaction costs which exceed the price which that User would receive from another User or Prospective User</li> </ul>
<b>Marketing Staff</b>	<p>servants, consultants, independent contractors or agents directly involved in sales, sale provision or advertising (whether or not they are also involved in other functions) but does not include servants, consultants, independent contractors or agents involved only in:</p> <ul style="list-style-type: none"> <li>(a) strategic decision making, including the executive officer or officers to whom Marketing Staff report either directly or indirectly;</li> <li>(b) technical, administrative, accounting or service functions</li> </ul>
<b>Natural Gas</b>	has the meaning given in the Gas Pipelines Access Law (that is, a substance which is in a gaseous state at standard temperature and pressure and which consists of naturally occurring hydrocarbons, or a naturally occurring mixture of hydrocarbons and non-hydrocarbons, the principal constituent of which is methane, and which has been processed to be suitable for consumption)
<b>New Facilities Investment</b>	has the meaning given in section 8.15 of the Code (that is, the Capital Base may be increased to recognise additional capital costs incurred in constructing, developing or acquiring New Facilities for the purpose of providing services)

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<b>New Facility</b>	means: <ul style="list-style-type: none"> <li>(a) any extension to, or expansion of the Capacity of, a Covered Pipeline which is to be treated as part of the Covered Pipeline in accordance with the Extensions/Expansions Policy contained in the Access Arrangement for that Covered Pipeline;</li> <li>(b) any expansion of the Capacity of a Covered Pipeline required to be installed under 6.22 of the Code (that is, where an Arbitrator requires such an expansion); and</li> <li>(c) any capital asset constructed, developed or acquired to enable the Service Provider to provide Services including, but not limited to, assets required for the purposes of facilitating competition in retail markets for Natural Gas</li> </ul>
<b>Non-capital Costs</b>	has the meaning given in section 8.4 of the Code (that is, the operating, maintenance and other non-capital costs incurred in providing all Services provided by the Covered Pipeline)
<b>Non Reference Service</b>	a service other than a Reference Service
<b>Optimised Deprival Value</b>	an asset valuation concept based on the cost that would be incurred by the owner of the asset if deprived of that asset, generally defined as the lesser of DORC and NPV/NRV
<b>Pipeline</b>	has the meaning given in the Gas Pipelines Access Law (that is, in summary, a pipe, system of pipes, or part of a pipe, for transporting natural gas, and any tanks, reservoirs, machinery or equipment directly attached to the pipe or system of pipes, but does not include anything upstream of an exit flange, a gathering system, any equipment used to remove or add components to or change natural gas, or anything downstream of a connection point to a customer)
<b>Prevailing Tariff</b>	for a Reference Service means the applicable Reference Tariff, and for any other Service, means the Equivalent Tariff
<b>Prospective Incremental User</b>	a person who may become an Incremental User
<b>Prospective User</b>	a person who seeks or who is reasonably likely to seek to enter into a contract for a Service and includes a User who seeks or may seek to enter into a contract for an additional Service
<b>Public Register</b>	the public register to be kept by the Code Registrar pursuant to section 7.10 of the Code
<b>Queensland Gas Appeals Tribunal</b>	the relevant local appeals body in Queensland
<b>Queuing Policy</b>	has the meaning given in section 3.12 of the Code (that is, an Access Arrangement must include a policy for determining the priority that a Prospective User has, as against any other Prospective User, to obtain access to Spare Capacity and Developable Capacity)
<b>Rate of Return</b>	has the meaning given in section 8.4 of the Code (that is, a return on the value of the capital assets that form the Covered Pipeline)

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<b>Rebatable Service</b>	is a Service where: <ul style="list-style-type: none"> <li>(a) there is substantial uncertainty regarding expected future revenue from sales of that Service due to the nature of the Service and/or the market for that Service; and</li> <li>(b) the nature of the Service and the market for that Service is substantially different to any Reference Service and the market for that Reference Service</li> </ul>
<b>Receipt Point</b>	the point or points within the Covered Pipeline at which the custody of Natural Gas is transferred from a User to a Service Provider
<b>Recoverable Portion</b>	has the meaning given in section 8.18 of the Code (that is, that part of a New Facilities Investment which meets the efficient investment test outline in section 8.16 of the Code, and which may therefore be included in the Capital Base)
<b>Redundant Capital</b>	has the meaning given in section 8.27 of the Code (that is, a Reference Tariff Policy may be required to have included a mechanism that will, with effect from the commencement of the next Access Arrangement Period, remove an amount from the Capital Base to ensure that assets which cease to contribute in any way to the delivery of Services are not reflected in the Capital Base, and to share costs associated with a decline in sales volume between the Service Provider and Users)
<b>Reference Service</b>	a Service which is specified in an Access Arrangement and in respect of which a Reference Tariff has been specified in that Access Arrangement
<b>Reference Tariff</b>	a Tariff specified in an Access Arrangement as corresponding to a Reference Service and which has the operation that is described in sections 6.13 and 6.18 of the Code
<b>Reference Tariff Policy</b>	has the meaning given in section 3.5 of the Code (that is, a policy describing the principles that are to be used to determine a Reference Tariff)
<b>Related Business</b>	the business of producing, purchasing or selling Natural Gas, but does not include purchasing or selling of Natural Gas to the extent necessary: <ul style="list-style-type: none"> <li>(a) for the safe and reliable operation of a Covered Pipeline; or</li> <li>(b) to enable a Service Provider to provide balancing services in connection with a Covered Pipeline</li> </ul>
<b>Relevant Appeals Body</b>	has the meaning given in the Gas Pipelines Access Law (that is, in relation to a decision of the local Regulator, the local appeals body. In the case of Queensland, the Queensland Gas Appeals Tribunal)
<b>Relevant Minister</b>	has the meaning given in the Gas Pipelines Access Law (that is, in relation to a scheme participant, the local Minister within the legislation for that scheme participant – for Queensland, this is the Treasurer)
<b>Relevant Regulator</b>	has the meaning given in the Gas Pipelines Access Law (that is, in relation to a transmission pipeline, the ACCC, and in relation to a distribution pipeline, the local Regulator. In the case of Queensland, the QCA is the Relevant Regulator)
<b>Revisions Commencement Date</b>	has the meaning given in section 3.17 of the Code (that is, the date upon which the next revisions to the Access Arrangement are intended to commence, to be approved by the Relevant Regulator)

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<b>Revisions Submission Date</b>	has the meaning given in section 3.17 of the Code (that is, the date upon which the Service Provider must submit revisions to the Access Arrangement, to be approved by the Relevant Regulator)
<b>Ring-fencing</b>	the requirement under section 4 of the Code for a Service Provider to establish arrangements to segregate its business of providing Services using a Covered Pipeline from other business activities
<b>Scheme Participant</b>	has the meaning given in the Gas Pipelines Access Law (that is, the Commonwealth, New South Wales, Victoria, Queensland, South Australia, Western Australia, Tasmania, the Australian Capital Territory and the Northern Territory)
<b>Service</b>	<p>a service provided by means of a Covered Pipeline (or when used in section 1 a service provided by means of a Pipeline) including (without limitation):</p> <ul style="list-style-type: none"> <li>(a) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul);</li> <li>(b) the right to interconnect with the Covered Pipeline; and</li> <li>(c) services ancillary to the provisions of such services,</li> </ul> <p>but does not include the production, sale or purchasing of Natural Gas</p>
<b>Services Policy</b>	has the meaning given in section 3.1 of the Code (that is, a policy on the Service or Services to be offered, including Services that are likely to be sought by a significant part of the market, or which the Relevant Regulator believes should be in the Services Policy)
<b>Service Provider</b>	has the meaning given in the Gas Pipelines Access Law (that is, the person who is, or is to be, the owner or operator or the whole or any part of the pipeline or proposed pipeline)
<b>Spare Capacity</b>	<p>means:</p> <ul style="list-style-type: none"> <li>(a) in relation to a Covered Pipeline described in the Access Arrangement as a Contract Carriage Pipeline: <ul style="list-style-type: none"> <li>(i) the difference between the Capacity and the Contracted Capacity; plus</li> <li>(ii) the difference between the Contracted Capacity and the Contracted Capacity which is being used; and</li> </ul> </li> <li>(b) in relation to a Covered Pipeline described in the Access Arrangement as a Market Carriage Pipeline, the capacity to provide a Service without impeding the provision of the Service to any other User</li> </ul>
<b>Speculative Investment</b>	has the meaning given in section 8.19 of the Code (that is, the difference between New Facilities Investment and the Recoverable Portion, less any amount the Service provider notifies the Relevant Regulator that it has elected to recover through a Surcharge. An amount determined as Speculative Investment may be subsequently added to the Capital Base if it satisfies the efficient investment test of section 8.16 of the Code)
<b>Speculative Investment Fund</b>	has the meaning given in section 8.19 of the Code (that is, the amount determined as Speculative Investment plus an annual increase in that amount at a rate of return approved by the Relevant Regulator, less any part of the Speculative Investment Fund previously added to the Capital Base)

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<b>Structural Element</b>	any principle or methodology that is used in the calculation of a Reference Tariff where that principle or methodology is not a Market Variable Element and has been structured for Reference Tariff making purposes over a longer period than a single Access Arrangement Period, and includes the Depreciation Schedule, the financing structure that is assumed for the purposes of section 8.30, and that part of the Rate of Return (calculated pursuant to section 8.30) that exceeds the return that could be earned on an asset that does not bear any market risk
<b>Surcharge</b>	has the meaning given in sections 8.25 and which has the effect defined in section 6.19 of the Code (that is, a Surcharge is a Charge in addition to the Charge that would apply under a Reference Tariff for a Reference Service that is levied on Users of Incremental Capacity in order for the Service Provider to recover some or all of the cost of New Facilities Investment that cannot be recovered at the Prevailing Tariffs)
<b>Take or Pay</b>	a contractual obligation on the part of the purchaser to pay for a certain quantity of gas at a minimum, irrespective of whether that quantity is used
<b>Tariff</b>	for a Service, means the criteria that, when applied to a User's characteristics and requirements, determine the Charge that is payable by that User to the Service Provider (this shall not provide any limitation on the Tariff that may apply to a Service)
<b>Tender Approval Request</b>	has the meaning given in section 3.21 of the Code (that is, any person who wishes to conduct a tender in relation to a Pipeline that has not been built may make an application to the Relevant Regulator requesting the Relevant Regulator to approve the use of a tender process to determine Reference Tariffs or other specified items required to be included in an Access Arrangement)
<b>Total Revenue</b>	has the meaning given in section 8.2 of the Code (that is, the revenue to be generated from the sales or forecast sales of all Services over the Access Arrangement Period)
<b>Trading Policy</b>	has the meaning given in section 3.9 of the Code (that is, a policy that explains the rights of a User to trade its right to obtain a Service to another person)
<b>User</b>	a person who has a current contract for a Service, or an entitlement to a Service as a result of an arbitration

## 1. INTRODUCTION

*The Queensland Competition Authority is the relevant regulator under the Gas Code (the Code) for approval of access arrangements for Queensland gas distribution networks. The Code provides guidance regarding the issues that must be considered before a revised access arrangement can be approved. The Authority has issued this Final Decision consistent with Code requirements, and proposes not to approve the revised access arrangement in the form submitted by Allgas. A number of amendments, as outlined in this Final Decision, are required before the revised access arrangement will be approved.*

### 1.1 QCA Responsibilities

The Queensland Competition Authority is a statutory body established under the *Queensland Competition Authority Act 1997*.

The Authority has responsibilities and functions with respect to natural gas distribution networks as outlined in the *Gas Pipelines Access (Queensland) Act 1998* (the Act). The Act gives effect to the National Third Party Access Code for Natural Gas Pipeline Systems (the Code). The Act and the Code are referred to in this decision as the Gas Law.

Access arrangements stipulate basic conditions under which third parties (generally retailers) can utilise the transmission and distribution networks in order to compete for the business of contestable customers. Access to gas transmission pipelines is regulated by the Australian Competition and Consumer Commission (ACCC).

Under the Code, an access arrangement must meet a number of requirements, including:

- non-pricing issues, namely:
  - (a) a services policy, which describes the services a provider will make available to users/prospective users;
  - (b) terms and conditions, outlining reasonable terms and conditions upon which each service is to be provided;
  - (c) a capacity management policy, incorporating a statement of whether the pipeline is to be operated on a contract carriage or a market carriage basis;
  - (d) a trading policy, which explains the rights of a user to trade or assign their right to obtain a service or contracted capacity to another person when the covered pipeline is a contract carriage pipeline;
  - (e) a queuing policy, which determines the priority prospective users have in gaining access to specific capacity, may be included for a distribution pipeline;
  - (f) an extensions/expansions policy, which describes the method for determining how an extension to or expansion of the pipeline is (or is not) to be treated for the purposes of applicability of the Code and how this will affect reference tariffs;
  - (g) a review date, which provides a date for submission of revisions to an access arrangement and a date upon which the revised access arrangement is to commence; and
- pricing issues, which relate to reference tariffs and a reference tariff policy. Reference tariffs are to correspond to each reference service provided while the reference tariff

policy is to describe the basis upon which tariffs are determined or are to change. Issues to be addressed include determining the capital base at the commencement of the regulatory period, a rate of return, depreciation, capital expenditure, revenue and the allocation of costs.

In assessing proposed revisions to an access arrangement, the Authority is required under section 2.46 of the Code to take the following matters into account:

- the service provider's legitimate business interests and investment in the covered pipeline;
- firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline;
- the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline;
- the economically efficient operation of the covered pipeline;
- the public interest, including the public interest in having competition in markets (whether or not in Australia);
- the interests of users and prospective users;
- any other matters that the Authority considers relevant; and
- the provisions of the access arrangement.

## **1.2 Implications of Possible Changes to the Gas Law and its Administration**

The Authority is mindful of possible changes to the Gas Law currently being examined by the Ministerial Council for Energy. Under current proposals, administrative responsibilities of the Gas Law will shift from Queensland to the Australian Energy Regulator from 1 January 2007.

However, the Authority is also mindful of its current role and responsibilities as the relevant regulator in Queensland. The Authority is required to approach this revision of access arrangements for Allgas in terms of its responsibilities currently set out in the Gas Law. The possibility of future changes to the Gas Law and shifts in administrative responsibility are not relevant when considering the task now before the Authority.

The Gas Law and its administration are evolving. This evolution will recognise the legitimate interests of service providers, users and prospective users.

## **1.3 Process for Approval of Revised Access Arrangement**

In reaching a Draft and Final Decision on a revised access arrangement, the Code requires a number of procedures to be followed. Broadly speaking, these procedures entail:

- submission by the service provider of both a revised access arrangement and accompanying access arrangement information to the Authority. The purpose of the latter is to provide interested parties with an understanding of how the various elements of the arrangement were determined and to enable them to form an opinion with regard to compliance with the Code;
- publication of a notice requesting submissions on the revised access arrangement;

- following consideration of submissions received on the revised access arrangement, the release of a Draft Decision by the Authority, along with a further call for submissions. This Draft Decision must, if it proposes not to approve the revised access arrangement, state the amendments (or nature of the amendments) which would have to be made to the access arrangement in order for the Authority to approve it; and
- after due consideration has been given to submissions on the Draft Decision, the release of a Final Decision by the Authority to either approve the access arrangement, or to approve it subject to revisions.

In accordance with the access arrangement approved in 2001, Allgas was required to submit its revised access arrangement, to apply from 1 July 2006 to 30 June 2011, to the Authority by 1 October 2005. A revised access arrangement was submitted on 30 September 2005 by Allgas.

The Authority released the revised access arrangement and access arrangement information provided by Allgas on 5 October 2005, along with a notice calling for submissions by 11 November 2005. A submission from Energex Retail was received (see Appendix A).

Having considered the revised access arrangement and the submission received, the Authority released its Draft Decision on Allgas' revised access arrangement on 21 December 2005. The Authority's Draft Decision was to not approve the revised access arrangement submitted by Allgas and outlined a number of amendments which would be required to be made in order for it to be approved. The Authority released a separate Draft Decision on Envestra's revised access arrangement at the same time.

In accordance with the provision of section 2.14 of the Code and consistent with the Authority's desire to facilitate an approval process which is transparent, rigorous, and provides for the involvement of all stakeholders, the Authority invited submissions on the Draft Decision from interested parties. Submissions were due to the Authority by 27 February 2006. Four submissions were received (see Appendix A).

As allowed for under the Code, Allgas made amendments to its revised access arrangement and accompanying access arrangement information and submitted this to the Authority on 27 February 2006. Allgas incorporated 15 of the required amendments from the Authority's Draft Decision and provided additional information to address the other 8 required amendments.

Having considered the submissions received in relation to the Draft Decision, the Authority is now issuing its Final Decision on Allgas' revised access arrangement. As was the case with the Draft Decision, the Authority has decided not to approve the access arrangement in its current form and has outlined a number of amendments which are required to be made in order for it to be approved. The Authority has released a separate Final Decision on the revised access arrangement submitted by Envestra.

In preparing the Draft Decision and this Final Decision, the Authority engaged consultants to provide expert advice in relation to certain aspects of the revised access arrangement. McLennan Magasanik Associates (MMA) was engaged to prepare independent gas demand forecasts to assist the Authority in determining whether the forecasts provided by Allgas are in accordance with section 8.2(e) of the Code. Energy Consulting Group (ECG) was employed to review the capital and non-capital costs incurred by Allgas over the current regulatory period and forecast for the next regulatory period. Allen Consulting Group (ACG) was engaged to provide advice on matters relevant to the rate of return to be earned by Allgas on its network assets over the next regulatory period. The Authority also engaged Associate Professor Martin Lally from Capital Finance Consulting to provide advice in relation to the value of imputation credits for regulated businesses.

Reports and submissions received by the Authority and used to prepare the Draft Decision and this Final Decision are outlined in Table 1.1 below.

**Table 1.1: 2006 Review of Access Arrangement - Timeline**

<i>Task</i>	<i>Date received/published</i>
Allgas' revised access arrangement received	September 2005
Closing date for submissions on revised access arrangement	November 2005
Demand Forecast Review	
MMA's Final Report released	December 2005
Capital and Operating Expenditure	
ECG's Final Reports released	December 2005
Cost of Capital	
ACG's Final Report released	December 2005
Capital Finance Consulting (Martin Lally) report released	December 2005
Draft Decision released	December 2005
Closing date for submissions on Draft Decision	February 2006
ECG's Final Report on revised capex/opex released	May 2006
MMA's Final Report on revised demand forecasts released	May 2006
Capital Finance Consulting report on gamma released	May 2006
<b>Final Decision released</b>	<b>May 2006</b>

## 1.4 Terminology

As noted above, Allgas submitted a revised access arrangement for the period 1 July 2006 to 30 June 2011 to the Authority on 30 September 2005. Following the Authority's Draft Decision, Allgas submitted amendments to its revised access arrangement on 27 February 2006. For simplicity, this Final Decision will refer to the 27 February 2006 submission as the 'revised access arrangement', unless comparison is being made between the two.

## 1.5 Document Structure

This Final Decision presents the Authority's views on all matters related to Allgas' revised access arrangement, which is to apply for the period 1 July 2006 to 30 June 2011. It is split into three main sections.

Chapter 2 provides an overview of Queensland's gas market.

Chapters 3-10 discuss the non-pricing issues in the revised access arrangement, which include the services policy, terms and conditions, capacity management policy, trading policy, queuing policy, extensions and expansions policy and the review date and review triggers.

Chapters 11-15 discuss the pricing issues in the revised access arrangement, outlining the Authority's decision on each component and the underlying rationale for these decisions.

## 2. NATURAL GAS PIPELINES IN QUEENSLAND

Queensland's gas market is characterised by a number of large transmission pipelines and several relatively small distribution networks. Around 140,000 customers are serviced by gas distribution systems.

Natural gas is produced in Queensland from the Bowen/Surat, Cooper/Eromanga and Adavale Basins. Gas is carried to end users via transmission pipelines and distribution networks. Access to transmission pipelines is regulated by the ACCC. Major transmission pipelines (see figure 2.1) include:

- the Wallumbilla to Brisbane pipeline;
- the Ballera to Wallumbilla pipeline;
- the Wallumbilla to Rockhampton pipeline;
- the Ballera to Mt Isa pipeline; and
- the South West Queensland Pipeline to Gilmore/Barcaldine pipelines.

**Figure 2.1: Queensland gas transmission pipelines<sup>1</sup>**



<sup>1</sup> Source: Energy Networks Association website.

Around 15 per cent of the gas consumed in Queensland is distributed via the covered pipeline systems owned by Allgas and Envestra. Table 2.1 indicates that while Envestra has more natural gas customers, it sells only half the volume of gas of Allgas.

**Table 2.1: Details of covered gas distribution networks in Queensland, 2004-05<sup>2</sup>**

<i>Owner</i>		<i>Number of customers</i>	<i>Total gas sold (PJ)</i>	<i>Length of mains (km)</i>
Allgas	Volume (< 10 TJ per annum)	64,413	2.7	2,304
	Demand (≥ 10 TJ per annum)	111	7.3	
	Total	64,524	10.0	
Envestra	Volume (< 10 TJ per annum)	74,641	1.9	2,172
	Demand (≥ 10 TJ per annum)	65	3.2	
	Total	74,706	5.1	

The Allgas distribution system is separated into four operating regions. These are:

- the Brisbane region (south of the Brisbane river);
- the Western region (including the townships of Toowoomba and Oakey);
- the South Coast region (including Gold Coast); and
- the Tweed Heads region in north east New South Wales.

The network comprises approximately 2,300 kilometres of low, medium and high pressure mains.

The Envestra network can be divided into two regions:

- the Brisbane region (including Ipswich and suburbs north of the Brisbane river); and
- the Northern region (serving Rockhampton and Gladstone).

The network consists of about 2,200 kilometres of low, medium, high and transmission pressure mains.

Since 2000-01, Allgas has added a further 339 km of natural gas mains to its network while Envestra added a further 104 km of mains to its network. Over the same period, Allgas increased its gas sales by around 4 per cent while Envestra increased its gas sales by around 16 per cent. Allgas' growth was mainly due to an increased number of volume customers whereas Envestra's growth was predominantly due to growth in large industrial customers.

This Final Decision is concerned with the access arrangement that relates to pipelines owned by Allgas and which are covered under the Gas Law.

<sup>2</sup> Source: Allgas and Envestra 2004-05 annual service quality reports.

### 3. SERVICES POLICY

*The services policy of an access arrangement determines the type and nature of services to be provided, including those to be provided as reference services (requiring the approval of a reference tariff) and non-reference services.*

*Allgas has proposed two reference services, for volume and demand customers, as well as ancillary services (special meter readings and inlet connections and disconnections) and additional services (negotiable services). Conditions associated with these services have not changed from those applying in the current access arrangement.*

*Allgas' services policy meets the requirements of the Code.*

#### 3.1 Introduction

In determining the terms and conditions that surround access to a gas distribution network, it is first necessary to decide what constitutes access (that is, what bundle of services is purchased when gaining access to the network) and how many different types of services may be offered.

A distribution network provides a physical connection between the transmission pipeline and an end user. Services provided in relation to this connection can include transportation of gas, odourisation, metering, connection, and so on, and may be bundled together under the terms and conditions of an access contract.

#### 3.2 Code Requirements

The Code (sections 3.1 and 3.2) provides that an access arrangement must include a policy on the service or services to be offered (a services policy). The services policy must comply with the following principles:

- the access arrangement must include a description of one or more services that the service provider will make available to users or prospective users, including:
  - (a) one or more services that are likely to be sought by a significant part of the market; and
  - (b) any service or services which in the Authority's opinion should be included in the services policy;
- to the extent practicable and reasonable, a user or prospective user must be able to obtain a service which includes only those elements that the user or prospective user wishes to be included in the service; and
- to the extent practicable and reasonable, a service provider must provide a separate tariff for an element of a service if this is requested by a user or prospective user.

The Code (section 3.3) also provides that an access arrangement must include a reference tariff for each service that is likely to be sought by a significant part of the market, for which the relevant regulator considers a reference tariff should be included (a reference service).

#### 3.3 Proposed Reference and Non-Reference Services

An access arrangement must define what services are to be provided. These services may be reference services or non-reference services. Reference services are those for which the

regulator approves a reference tariff, while non-reference services are any other services listed in the access arrangement.

#### *Allgas' proposal*

Allgas (section 2 of the access arrangement) has provided for three network services, namely:

- reference services (demand and volume);
- ancillary services; and
- additional services.

Reference services are further defined as:

- a demand customer service, which applies to end users with an annual throughput of at least 10 TJ; and
- a volume customer service, which applies to end users with an annual throughput of less than 10 TJ.

Both these services include the associated services of forward haulage of gas, installation and reading of meters, connection and pressure regulation. Odourisation is provided by Allgas as part of these services as detailed in section 6.1 of its terms and conditions.

Ancillary services are further defined as:

- special meter reading;
- inlet disconnection service; and
- inlet reconnection service.

Additional services are described by Allgas as services other than reference services for which terms and conditions may be negotiated. Allgas has undertaken to provide separate tariffs for additional services where it is practical, reasonable and commercially viable to do so.

#### *Other jurisdictions*

IPART (2005a) approved the services policy included in the revised access arrangement for the Country Energy Gas Network. The services policy included transport reference services, additional services and negotiated services that are similar to those set out by Allgas.

#### *Submissions from stakeholders*

No comments were made on this issue in submissions.

#### *QCA position*

The revised access arrangement for Allgas retains the key elements of the services policy set out in the current access arrangement. The reference and non-reference services as defined appear to be those that most users or prospective users would seek from the service provider.

Consequently, the services policy meets the requirements of the Code.

The Authority accepts the proposed services policy of Allgas.

## 4. TERMS AND CONDITIONS

*Section 3.6 of the Code requires the Authority to form an opinion as to whether the proposed terms and conditions are reasonable. Reasonableness must be determined having regard to the role to be played by the conditions of supply in the access arrangement. That is, the conditions represent standard contract terms on which the service provider is required to agree to supply the reference service. They are also taken into account in any arbitration to resolve a dispute concerning the terms of access.*

*In assessing the reasonableness of the terms and conditions, the Authority is also required by section 2.46 of the Code to take into account:*

- (a) the factors described in section 2.24 of the Code; and*
- (b) the provisions of the current access arrangement.*

*The Authority notes that, in most instances, the proposed terms and conditions are the same as those that were approved for the current access arrangement. Where the Authority has formed the view that these current terms and conditions are reasonable having regard to the matters in section 2.46, the terms have been accepted without setting out the Authority's reasoning separately in this Chapter.*

*However, where Allgas has revised an existing provision, the stakeholders have suggested changes or the Authority considers that existing terms and conditions are no longer consistent with the Code, this Chapter sets out the Authority's detailed reasons for its decision.*

*In its Draft Decision, the Authority required Allgas to make some changes to its proposed terms and conditions. Allgas accepted several of those changes in the amended version of its revised access arrangement now being considered. However, some further changes are still required as indicated in this Chapter.*

### 4.1 Introduction

The terms and conditions of a contract form the basis of the relationship between the service provider and the user. A monopoly provider of a good or service has the ability to adopt a 'take it or leave it' approach to the terms and conditions on which it operates, with the effect of shifting risk from the service provider to the user.

In its Draft Decision, the Authority required Allgas to make a number of amendments to its proposed terms and conditions. In response to the Authority's Draft Decision, Allgas submitted an amended version of its revised access arrangement in which Allgas included several of the amendments required by the Authority. As the amended revised access arrangement is now the relevant document to be considered by the Authority, this Chapter only discusses those terms and conditions that the Authority considers still require further amendment or that stakeholders have expressed concern about in submissions on the Draft Decision.

Allgas has included its terms and conditions as Appendix C to its access arrangement. Unless otherwise stated, the references in the following sections are to the relevant terms and conditions.

### 4.2 Code Requirements

Section 3.5 of the Code states that an access arrangement must include the terms and conditions on which the service provider will supply each reference service. The terms and conditions included must, in the Authority's opinion, be reasonable.

### 4.3 Capacity Management – Network Limitations

Gas distribution networks require a certain pressure of gas to operate and maintaining this pressure requires management by the service provider. The service provider has an obligation to manage the network in a manner which satisfies the terms and conditions of the agreement.

#### *Allgas' proposal*

In its Draft Decision, the Authority required Allgas to amend its terms and conditions so that it would have an obligation to maintain the network in accordance with good engineering and industry practices.

Allgas updated section 3.4 of its revised terms and conditions to require it to maintain the network in accordance with good engineering and industry practice but argued that 'good engineering and industry practice' was subjective and that it would prefer section 3.4 refer to statutory obligations.

#### *Submissions from stakeholders*

TRUenergy (2006) agreed with Amendment 4.3 from the Authority's Draft Decision, although it suggested that "good engineering and industry practices" could be replaced with "best engineering and industry practices".

The Queensland Government (2006) disagreed with the Amendment, noting that good engineering and industry practices was subjective, could vary and may conflict with relevant legislation. The Queensland Government suggested that the distributor be required to maintain the network in accordance with the legislated requirements.

#### *QCA position*

The Authority is satisfied that Allgas has made the amendment that was required in the Draft Decision. However, the Authority accepts the views of Allgas and the Queensland Government that 'good engineering and industry practice' is a subjective requirement, although this is a term used within the Code (see section 8.37 for example). The Authority accepts that maintaining the network according to relevant legislation and statutory obligations (where these cover such matters) would be a more objective requirement that meets the requirements of the Code. For this reason, the Authority has decided to require that the section 3.4 of the terms and conditions be amended to require Allgas to maintain the network in accordance with any legislative and statutory requirements where relevant and, to the extent not covered by legislation, in accordance with good engineering and industry practice.

#### **Amendment 4.1**

**In order for Allgas' access arrangement to be approved, Allgas must amend section 3.4 of the terms and conditions so that Allgas will have an obligation to maintain the network in accordance with legislative and statutory requirements where relevant and, to the extent not covered by legislation, in accordance with good engineering and industry practice.**

### 4.4 Supply Curtailment – Order of Priority

On occasions, a service provider may need to curtail service to particular locations in order to undertake necessary repairs or to protect the operational integrity and safe operation of the

network. Where complete cessation of gas transportation is not required, an order of priority by which users will face curtailment of service is required.

In certain circumstances, the relevant Minister has the power to determine the order of curtailment.

#### *Allgas' proposal*

In its revised access arrangement, Allgas removed existing provisions which established the order of priority in instances where it was necessary to curtail supply.

In its Draft Decision, the Authority required Allgas to include a section in its terms and conditions that outlined the order of priority with which interruptions or curtailments to reference services would take place. Where there were several users of reference services with the same priority, the Authority required that Allgas treat these users on an equitable basis. Both of these requirements were covered in Allgas' existing access arrangement.

In its response to the Draft Decision, Allgas argued that it was the contractual relationship between the user (the retailer) and their customers covering the supply of gas that provides the basis for managing curtailment. This allows the user to curtail supply as per the conditions agreed with the customer.

#### *Submissions from stakeholders*

Energex Retail (2005) noted that Allgas and Envestra had proposed different approaches to handling curtailment and interruptions to the network. Energex Retail sought clarification from the Authority on the ability of a service provider to curtail or interrupt supply for the purpose of safety and maintenance. Energex Retail suggested that it should be the responsibility of the retailer to determine how curtailment is accomplished as the retailer is the supplier of gas to end-users.

Origin Energy (2005) argued there may be a risk that Envestra will inappropriately categorise customers for determining the priority for curtailment. While Origin Energy raised this issue in relation to Envestra, it applies equally to Allgas under the arrangements proposed by the Authority. Origin Energy considered that the clause dealing with this matter should be amended to allow a customer the ability to request from Envestra [Allgas] an explanation as to its decision on the category to which the customer belongs.

TRUenergy (2006) agreed with the amendment required by the Authority and noted that information disclosure is imperative at times of curtailment.

The Queensland Government (2006) argued that it was more appropriate for the retailer to be responsible for determining the order of curtailment. This would enable the retailer to curtail customers in accordance with the agreed terms and conditions of its gas supply contracts. The Queensland Government argued that this position was consistent with the view expressed by the Ministerial Council on Energy in relation to major supply disruptions. The Queensland Government encourages retailers to develop curtailment strategies in consultation with the distributor.

#### *QCA position*

In its Draft Decision, the Authority required Allgas to reinstate the existing provisions in its terms and conditions establishing an order of priority for interruption or curtailment of reference services, and a policy for situations where there are several users with the same priority.

The Authority was also of the view that the suggestion made by Origin Energy was a reasonable one and should apply to Allgas as well as to Envestra. The Authority therefore required Allgas to adjust its terms and conditions so that a customer can request an explanation as to why it was placed in a particular category.

While the Authority was not convinced that retailers should determine the order of curtailment, as suggested by Energex Retail, it did agree that a retailer should have access to information regarding the curtailment priority for its customers and that it would be reasonable for Allgas to provide an opportunity for retailers to comment on the proposed order of priority.

Notwithstanding the views expressed by the Queensland Government, the Authority considers that, as the network operator, rather than the retailer, will have to act to curtail supply in an emergency or other situations, the network operator must have the final say on the priority of curtailment. This is even more important if there are a large number of retailers, which could become the case under full retail contestability. In this regard, the Authority notes that the access arrangements of most service providers in Australia include an order of priority.

At the same time, it is appropriate that the service provider clearly outline the order of priority for curtailment in its terms and conditions.

It would be expected that the distributor would seek the views of retailers in establishing the order of priority. In addition, there is nothing to prevent a retailer from providing the service provider with information that supports the case for a delivery point to be classified at a certain priority level.

The Authority also notes that in certain instances the relevant Minister has over riding powers which provide for the Minister to determine the order of curtailment.

#### **Amendment 4.2**

**In order for Allgas' access arrangement to be approved, Allgas must include provisions in sections 12 of its terms and conditions that:**

- **set out the order of priority with which various types of users will be subject to interruptions or curtailments of reference services;**
- **sets out how Allgas will treat users of reference services with the same priority when interrupting or curtailing reference services, noting that users with the same priority should be treated in an equitable manner; and**
- **provide customers with the right to request an explanation from Allgas as to why they have been placed in a particular category.**

#### **4.5 Other Issues**

In response to the Authority's Draft Decision, TRUenergy proposed a number of amendments to Allgas' terms and conditions. These issues had not previously been raised by other stakeholders, the service providers or the Authority. The Authority sought a response from Allgas in relation to the specific issues raised by TRUenergy.

The issues raised by TRUenergy (2006) were as follows:

- the limitation of liability in the Allgas proposed terms and conditions should be removed so that it is consistent with standard terms and conditions in other markets. TRUenergy argued that the limit of \$100,000 currently proposed by Allgas is unreasonable;

- the distributor had no need to require access to information on producers and TRUenergy objected to providing details of upstream gas contract arrangements as it saw this as highly unusual and may include confidential information. TRUenergy also suggested that the gas balancing obligation (clause 3.5) may be difficult for retailers to meet;
- in the case of a dispute over payment, the terms and conditions should require the retailer to only pay the amount of the invoice not genuinely disputed;
- given the nascent state of market rules in Queensland, it would be appropriate for the terms and conditions to include a requirement for the parties to review and negotiate amendments in good faith in the event of regulatory change; and
- the terms and conditions should include a provision for the distributor to indemnify the retailer for claims by customers relating to quality of, or interruptions to, the supply of gas.

#### *Allgas' response*

At the request of the Authority, Allgas responded to the issues raised by TRUenergy.

With respect to the limitation of liability, Allgas noted that, any claims made against Allgas due to its negligence were unlimited and that it was only Allgas' liability in relation to consequential losses for other reasons that was limited. Allgas suggested that the limit of liability of \$100,000 per year was required as Allgas does not hold insurance for such events (as it is not cost effective to do so). Allgas noted that it was not compensated for such risk in its rate of return. Allgas also argued that it was usual practice within the energy industry for a service provider to limit its liability for consequential losses.

In regard to the issues of confidential information and upstream contract information, Allgas argued that it required this information in order to meet its responsibilities as market operator. Until these circumstances change, it has no choice but to continue to seek this information.

Allgas considered that the TRUenergy proposal in relation to disputed invoices would potentially create revenue/billing uncertainty to Allgas, particularly as the proposal is dependent on the definition of 'genuinely'. Allgas argued that its terms and conditions set out a reasonable and fair process for managing disputed invoices and that the TRUenergy proposal would be difficult to administer.

In regard to the TRUenergy suggestion that there be a review of terms and conditions in the event of regulatory change, Allgas noted that its access arrangement was being set for five years and that the revenues for delivering the service relate to the terms and conditions for the reference service. Allgas argued that to require the terms and conditions to be subject to a review represents a misunderstanding of access regulation and that the only way that such a proposal could work would be if the whole access arrangement was reviewed at the same time. Allgas also noted that any cost allowance for a change in rules will be subject to a cost pass-through application at the appropriate time.

Allgas did not accept the notion of indemnifying retailers for the quality and supply of gas to customers as it would require Allgas to intervene in the retailer-customer relationship and would result in a misallocation of risk.

*QCA position*

The Authority has considered the issues raised by TRUenergy and the response that it has received from Allgas. The Authority notes that the terms and conditions proposed by Allgas are consistent with those that were approved in the current access arrangement.

The Authority considers that TRUenergy has not made a strong enough case to convince it to require amendments to terms and conditions that are included in the current access arrangement. The responses received from Allgas in relation to each of the suggestions made by TRUenergy are reasonable. However, in relation to disputed invoices, the Authority accepts that this could become a problem if the service provider did not seek to resolve disputes in a timely fashion. For this reason, the Authority requires Allgas to report information on the number of disputed invoices, the time taken to resolve the dispute, the amounts in dispute and the outcome of the dispute, as part of its annual service quality reporting. Should this information reveal an unacceptable trend in the resolution of disputed invoices, this particular condition would need to be reconsidered at the next review. Other than recognising this reporting requirement, the Authority does not require Allgas to make any amendments to its terms and conditions based on the comments received from TRUenergy.

## 5. CAPACITY MANAGEMENT POLICY

*Allgas has proposed that its covered pipeline be treated as a contract carriage pipeline.*

### 5.1 Introduction

The capacity management policy establishes how capacity in the pipeline will be allocated, either by way of set contracts or on a continuous, spot basis. These two approaches differ, among other things, in the way they apportion risk between market participants. A contract carriage pipeline will have most (if not all) available capacity contracted to specific users. The owner of the pipeline will thus have very little exposure to risks associated with future use of the pipeline. Conversely, with a market carriage pipeline, the majority of capacity is available for short-term use with the owner facing any risk associated with failure to sell available capacity.

### 5.2 Code Requirements

Under sections 3.7 and 3.8 of the Code, an access arrangement must include a statement (a capacity management policy) that the covered pipeline is either:

- (a) a contract carriage pipeline (that is, a pipeline where capacity is contracted to particular users); or
- (b) a market carriage pipeline (that is, a pipeline that relies on spot prices based on actual usage of services).

The relevant regulator must not accept an access arrangement which states that the covered pipeline is a market carriage pipeline unless the relevant minister of each scheme participant (state and territory) in whose jurisdictional area the pipeline is wholly or partly located has given a notice to the relevant regulator permitting the covered pipeline to be a market carriage pipeline.

### 5.3 Issues Concerning the Capacity Management Policy

#### *Allgas' proposal*

Allgas (section 8 of the access arrangement) has stated that its covered pipeline is a contract carriage pipeline.

#### *Other jurisdictions*

Distribution service providers in most other jurisdictions have proposed that their distribution networks be treated as contract carriage pipelines. These proposals have been accepted by the relevant regulator. In Victoria, Multinet, TXU and Envestra proposed a market carriage pipeline, which was a continuation of existing arrangements. The ESC (2002) accepted this, noting the differences between a contract carriage system and a market carriage system were not particularly marked for a distribution system.

#### *Submissions from stakeholders*

No comments were made on this issue in submissions.

*QCA position*

The Authority has not been notified that any Queensland pipelines covered by the Code are permitted to be market carriage pipelines. Accordingly, all covered pipelines are required to be contract carriage pipelines.

The Authority accepts the proposal by Allgas that its network be treated as a contract carriage pipeline.

## 6. TRADING POLICY

*As the distribution network is a contract carriage pipeline, the access arrangement for Allgas is required to include a trading policy to meet the minimum requirements of the Code.*

### 6.1 Introduction

A trading policy allows a user to transfer contracted capacity to another user. A trading policy is an integral element of contract carriage systems, enabling a secondary market to determine efficient pricing signals and levels of capacity usage. However, because there is unlikely to be any direct gain (primarily in terms of revenue) to the service provider from trading, the Code protects the rights of users to have maximum flexibility to trade and limits the service provider's ability to deny this right.

### 6.2 Code Requirements

Where a pipeline is a contract carriage pipeline, section 3.9 of the Code states that the access arrangement must include a trading policy which explains the rights of a user to trade their right to obtain a service to another person. The trading policy must (section 3.10), amongst other things, allow a user to transfer their contracted capacity:

- without the service provider's consent, if the contract between the user and the service provider is unaltered by the transfer (a bare transfer); and
- with the service provider's consent, in any other case. Consent may be withheld by the service provider only on reasonable commercial or technical grounds and the trading policy may specify conditions under which such consent will be granted and any conditions attaching to that consent.

The trading policy must also permit a change to a delivery or receipt point, where commercially and technically reasonable, and with the prior written consent of the service provider. It may also specify conditions under which such consent will, or will not, be given and any conditions attaching to that consent.

### 6.3 Issues Concerning the Trading Policy

#### *Allgas' proposal*

The trading policy submitted by Allgas is essentially the same as the trading policy in the current access arrangement. The one difference is that Allgas has proposed that it will reply to any request for consent to a transfer within 10 business days of receiving the request, as opposed to the 14 business days in the current access arrangement.

The trading policy permits bare transfers without Allgas' consent provided the transferee, prior to utilising this right, gives notification of the portion of the contracted capacity subject to the bare transfer and of the nature of the transfer.

For any other form of transfer, the network user is required to seek Allgas' consent. Allgas may only withhold consent on reasonable commercial and technical grounds.

The proposed trading policy permits changes to delivery and receipt points with the prior written consent of Allgas and where the change is commercially and technically reasonable.

The trading policy stipulates that administrative fees associated with investigating the technical and commercial feasibility of any application for transfer will be applied to the party requesting

the transfer. The fee would vary depending on the complexity of the transfer analysis, but must be charged on a reasonable basis.

#### *Other jurisdictions*

In regard to the discretion of the service provider to set reasonable grounds for non-bare transfers, IPART (2005) considered that AGLGN's proposal was acceptable. AGLGN proposed that it would respond to requests for non-bare transfers and to change of a receipt or delivery point within 14 days of receiving the request and that it would endeavour to respond within 2 working days in cases of hardship.

ICRC (2004) required the same provision to be made for transfers (other than bare transfers), for the service provider in the Australian Capital Territory, Queanbeyan and Yarralumla region.

#### *Submissions from stakeholders*

No comments were made on this issue in submissions.

#### *QCA position*

##### Allgas

The trading policy that has been proposed by Allgas is consistent with the Code and is essentially the same as the trading policy approved in the current access arrangement. The Authority does not require any amendments to be made to Allgas' trading policy.

## 7. QUEUING POLICY

*Queuing provides a mechanism by which the right of access to a pipeline is determined where capacity is fully, or close to fully, utilised. For transmission pipelines, the Code requires an access arrangement to contain a queuing policy. However, for distribution networks the inclusion of a queuing policy is optional, with the approval of the relevant regulator.*

*Allgas has not included a queuing policy in its revised access arrangement. The Authority accepts that it is unlikely that queues would be required in order to accommodate prospective users of the distribution networks. Consequently, the Authority does not require a queuing policy to be included in the revised access arrangement.*

### 7.1 Introduction

Queuing for a good or service is one means of rationing access where that good or service is scarce (adjusting the price being another). Given the Code provides for reference tariffs to be approved by regulators, raising prices to ration demand is not available as an option to gas distribution service providers in the short term. Queuing therefore provides a mechanism by which the right of access to a pipeline can be determined where capacity is fully, or close to fully, utilised.

With respect to distribution networks, a queue is but one of several means by which new users can be accommodated. In general, new users will be able to be accommodated because, unlike transmission pipelines, distribution networks do not operate at full or near to full capacity. Rather, the networks typically have varying amounts of spare capacity at different points across the entire network. Where network capacity at one point on the network is reaching capacity, augmentation of the network will normally be undertaken to meet the needs of prospective users.

### 7.2 Code Requirements

Sections 3.12 to 3.15 of the Code outline the requirements for a Queuing Policy in relation to covered transmission and distribution pipelines. In 2003, the Code was varied to permit distribution network service providers to exclude a queuing policy from their access arrangement with the approval of the regulator. In particular, section 3.12(d) indicates the relevant regulator should consider the nature and service likely to be sought by prospective users before requiring the service provider to include a queuing policy.

### 7.3 Allgas Proposal

#### *Allgas' proposal*

Allgas has suggested that a queuing policy is not required for distribution networks as network development can occur in small increments at different points on the network to meet demand. In the rare instance that two or more new large customers were to seek access to the network at the same time and point, Allgas has stated that access to dedicated capacity for each customer would be negotiated at the time of connection.

#### *Other jurisdictions*

With respect to Envestra's South Australian distribution network, ESCOSA (2005b) has indicated in its Guidance Paper that it does not expect to require Envestra to include a queuing policy in the access arrangement for its South Australian network. However, ESCOSA indicated that it would consider any potential for future congestion of the network emerging, or

as a result of rules stemming from full retail contestability, once the revised access arrangement was submitted.

IPART (2005) required AGLGN to include a queuing policy because parts of the distribution network were technically transmission pipelines. However, in relation to Country Energy, IPART (2005a) did not require a queuing policy because that distribution network is a contract carriage pipeline with spare capacity.

In general, other jurisdictional regulators appear to be adopting the view that, where a distribution network is not affected by congestion, a queuing policy will not be required.

#### *Submissions from stakeholders*

No comments were made on this issue in submissions.

#### *QCA position*

The Authority accepts Allgas' argument that queues are unlikely to form due to a lack of capacity on the network. On this basis, a queuing policy would not appear to be necessary. Therefore, the Authority accepts that the access arrangement not include a queuing policy.

## 8. EXTENSIONS/EXPANSIONS POLICY

*An extensions/expansions policy needs to address whether or not any extension to, or expansion of, the capacity of the gas distribution system will be treated as part of the covered pipeline. A service provider is also required to specify the impact on reference tariffs of including an extension/expansion within the covered pipeline.*

*Where a service provider requests the exclusion of a significant extension that is connected directly to the covered network, and where the Authority provides written consent for this to occur, the Authority may require that some portion of the revenue generated by that extension be offset against the total revenue calculation for the covered pipeline, in recognition of the use of common or joint assets that form part of the covered pipeline.*

*The Authority considers that Allgas' proposed mechanisms for determining whether a particular extension/expansion will be treated as part of the existing system are consistent with the Code.*

*The Authority considers that Allgas' proposed pricing arrangements for extensions/expansions are consistent with the Code.*

### 8.1 Introduction

An access arrangement must include a policy setting out a method for determining whether an extension or expansion to the covered pipeline is to be treated as part of the covered pipeline.

An extension or expansion raises two particular issues:

- whether it should be treated as part of the existing system (and therefore 'covered' automatically) or treated as a stand-alone system; and
- if included as part of the existing system, how the use of that extension or expansion should be priced.

### 8.2 Code Requirements

Section 3.16 of the Code states that an access arrangement must include a policy (an extensions/expansions policy) which:

- (a) sets out the method to be applied to determine whether any extension to, or expansion of, the capacity of the covered pipeline:
  - (i) should be treated as part of the covered pipeline for all purposes under the Code; or
  - (ii) should not be treated as part of the covered pipeline for any purpose under the Code;

For example, the extensions/expansions policy could provide that the service provider may, with the relevant regulator's consent, elect at some point in time whether or not an extension or expansion will be part of the covered pipeline.

- (b) specifies how any extension or expansion which is to be treated as part of the covered pipeline will affect reference tariffs. For example, the extensions/expansions policy could:
  - (i) provide that reference tariffs will remain unchanged but a surcharge may be levied on incremental users where permitted by sections 8.25 and 8.26; or

- (ii) specify that a review will be triggered and that the service provider must submit revisions to the access arrangement pursuant to section 2.28; and
- (c) provides if the service provider agrees to fund new facilities if certain conditions are met, a description of those new facilities and the conditions on which the service provider will fund the new facilities.

Sections 8.25 and 8.26 of the Code relate to surcharges, which may be levied on incremental users in order for a service provider to recover some or all of the cost of new facilities that cannot be recovered at the prevailing reference tariff. Surcharges are chargeable unless precluded by the extensions/expansions policy and upon written notice to, and approval by, the Authority.

### 8.3 Coverage of Extensions and Expansions

The Code firstly requires that the extensions/expansions policy outline if an extension to, or expansion of, a network is to be treated as part of the covered pipeline.

#### *Allgas' proposal*

Allgas' extensions/expansions policy (section 7 of the revised access arrangement) is essentially the same as that which was approved in the 2001 access arrangement. The only change is that a significant extension is now defined as an extension of the network to connect one or more delivery points, where the anticipated quantity of gas delivered exceeds 10 TJ per year and the anticipated capital expenditure for the extension exceeds \$1 million. In the current access arrangement, the amount of capital expenditure specified in the definition is only \$200,000.

In line with its current access arrangement, Allgas has proposed that a distinction be drawn between network extensions (adding additional lines of main or infrastructure to the network) and network expansions (adding additional capacity to the existing network). In the case of network extensions, Allgas has proposed that these would automatically be treated as part of the covered pipeline unless the extension is a significant extension and Allgas obtains the Authority's written approval to exclude the extension from the network.

In the case of network expansions, Allgas has proposed that all network expansions will be automatically treated as part of the covered pipeline upon the expansion coming into service.

#### *Other jurisdictions*

IPART (2005) required AGL to include an extension or expansion as part of the covered pipeline unless AGL had obtained the Tribunal's consent to exclude it.

The ESCV (2002) required that all non-significant expansions must be covered by the existing access arrangement. Significant extensions can be excluded from the access arrangement and treated as stand-alone systems when the distributor provides prior written notification to the regulator. A significant extension is defined as one that will service a minimum of 5,000 customers.

ICRC (2004) required that all extensions or expansions were treated as part of the covered pipeline unless the extension or expansion was significant. This would be determined on a case-by-case basis by the Commission.

The ACCC (2003) noted that in previous decisions the Commission had required that, where a pipeline is operating at or near capacity, expansions to the pipeline should be covered, unless the regulator considers otherwise.

### *Submissions from stakeholders*

There were no submissions from stakeholders on this issue.

### *QCA position*

The Authority is of the view that the intention of the Code, in general, is that extensions to, and expansions of, covered pipelines should be covered by the access arrangement. However, at the time of the previous review of the proposed access arrangement, the Authority recognised that, by requiring all extensions and expansions to be included in the covered network, it could potentially be reducing a service provider's degree of flexibility in terms of contractual arrangements with prospective customers. The Authority decided to allow significant extensions to be excluded from the covered pipeline, subject to the prior written approval of the Authority. In deciding whether to approve a request for an extension to be excluded, the Authority indicated it would have regard to, among other things, the number of customers connected (or likely to be connected) to the extension and the risk profile of the extension.

The proposal put forward by Allgas is almost identical to that which was approved by the Authority in the 2001 access arrangement. The Authority is satisfied that all extensions and expansions will be automatically treated as part of the covered network, except for significant extensions which may be excluded subject to the approval of the Authority.

The only material change in Allgas' extensions/expansions policy from the current arrangement is that, for an extension to be deemed to be a significant extension, the anticipated capital expenditure for the extension must exceed \$1 million (the anticipated quantity of gas delivered must also exceed 10 TJs per year). The current access arrangement only requires capital expenditure of \$200,000.

The Authority is of the view that the definition of significant extension should include both a capital expenditure component and a gas throughput component. The Authority notes that Allgas' proposal meets this requirement. Increasing the capital expenditure requirements from \$200,000 to \$1 million means that extensions are more likely to be covered by the approved access arrangement than would otherwise be the case. Were the proposed changes to have the opposite effect and potentially exclude more extensions from coverage, the Authority may have some concerns. However, raising the limit does not raise any issues and is accepted.

The Authority accepts Allgas' extensions/expansions policy.

## **8.4 The Effect of Coverage on Reference Tariffs**

The second Code requirement in respect of the extensions/expansions policy is for the service provider to specify the impact on reference tariffs of including any extension/expansion within the covered pipeline.

### *Allgas' proposal*

Allgas has proposed that, where an extension meets the prudence test detailed in section 8.16 of the Code, there will be no adjustment to the prevailing tariff. However, where an extension (either covered or excluded) is for the purpose of supplying an additional end user or group of end users, and the extension does not meet the economic feasibility test in section 8.16(a)(ii)(A), a capital contribution or surcharge for the incremental user/s may be charged by Allgas. Neither the capital contribution amount nor the net present value of the surcharge amounts shall exceed the capital cost of constructing the extension. In these circumstances, no adjustment will be made to the reference tariff prevailing prior to the extension and the user(s) will pay the

prevailing tariff plus the capital contribution or surcharge amount as determined by Allgas. Neither the capital contribution nor the net present value of the surcharge amounts shall exceed the capital cost of constructing the extension.

In the case of *expansions*, Allgas' policy states that there will be no adjustment to the prevailing tariff arising from an expansion necessary to maintain the safety, integrity or contracted conditions of the network where such expansion meets the new facilities investment test detailed in section 8.16 of the Code. However, where expansion is necessary to maintain the safety, integrity or contracted conditions of the network for a particular end user or group of end users and where section 8.16 of the Code is not satisfied, Allgas may require the provision of a capital contribution or surcharge to be applied to the end user or group of end users. In these circumstances, no adjustment will be made to the reference tariff prevailing prior to the augmentation and the end user(s) will pay the prevailing tariff plus the capital contribution or surcharge amount as determined by Allgas. If the augmentation has system wide benefits that justify the approval of a higher reference tariff for all users, Allgas may seek the Authority's approval for an increase in the reference tariff, in accordance with section 8.16(a)(ii)(B) of the Code.

#### *Other jurisdictions*

Other regulators have generally required reference tariffs to remain unchanged when an extension/expansion is covered, but have allowed the service provider to charge a surcharge in certain circumstances as is permitted in the Code.

#### *Submissions from stakeholders*

There were no submissions from stakeholders on this issue.

#### *QCA position*

Allgas' proposal to address the effect of an extension/expansion on reference tariffs is based on the prudence and economic feasibility tests contained in section 8.16 of the Code. This section allows the capital base to be increased for new facilities investment whenever this investment meets certain requirements. The amount must not exceed the amount invested by a prudent service provider acting efficiently, in accordance with good industry practice, and to achieve the lowest sustainable cost of providing services. In addition, the anticipated incremental revenue generated by the new facility must exceed the new facilities investment, or the service providers and/or users must satisfy the regulator that the new facility has system-wide benefits that justify the approval of higher reference tariffs, or the new facility is necessary to maintain the safety, integrity or contracted capacity of services.

Allgas' policy is the same as that which was approved in the current access arrangement.

The Authority is of the view that Allgas' proposed approach in respect of pricing for an extension/expansion is consistent with section 3.16(b) of the Code.

## 9. REVIEW DATE

*The Authority has accepted the proposal by Allgas that the access arrangement period will be from 1 July 2006 to 30 June 2011. The Authority also accepts that a revised access arrangement will be required to be submitted to the relevant regulator nine months prior to 1 July 2011.*

*The Authority has accepted that, unlike the current access arrangement, the next access arrangement not include a trigger mechanism that would allow a review of the access arrangement in the event that actual demand is sufficiently different from forecast demand. The Authority considers that demand forecasts should be more reliable in the next access arrangement period as they are based on more, and better, information.*

### 9.1 Introduction

A five year period between regulatory reviews provides service providers with significant regulatory certainty in terms of both the commercial parameters they operate within and the opportunity to accrue efficiency gains during that period.

### 9.2 Code Requirements

Under sections 3.17 to 3.20 of the Code, an access arrangement must include:

- (a) a date upon which the service provider must submit revisions to the access arrangement (a revisions submission date); and
- (b) a date upon which the next revisions to the access arrangement are intended to commence (a revisions commencement date).

In approving the revisions submission date and revisions commencement date, the relevant regulator must have regard to the objectives in section 8.1 of the Code. In making its decision on an access arrangement (or revisions to an access arrangement), the regulator may, if it considers it necessary, having had regard to the objectives in section 8.1:

- (c) require an earlier or later revisions submission date and revisions commencement date than proposed by the service provider in its proposed access arrangement; and
- (d) require that specific major events be defined that trigger an obligation on the service provider to submit revisions prior to the revisions submission date.

An access arrangement period accepted by the relevant regulator may be of any length. However, if the access arrangement period is more than five years, the relevant regulator must not approve the access arrangement without considering whether mechanisms should be included to address the risk of forecasts, on which the terms of the access arrangement were based and approved, proving incorrect. These mechanisms may include (section 3.18):

- (a) requiring the service provider to submit revisions to the access arrangement prior to the revisions submission date if certain events occur, for example:
  - (i) if a service provider's profits derived from a covered pipeline are outside a specified range or if the value of services reserved in contracts with users are outside a specified range;
  - (ii) if the type or mix of services provided by means of a covered pipeline changes in a certain way; or

- (b) a service provider returning some or all revenue or profits in excess of a certain amount to users, whether in the form of lower charges or some other form.

### **9.3 Dates for Submitting and Commencing Revisions**

As noted above, the length of time the access arrangement is in effect is an important issue. Another issue is the length of time the service provider must allow for the regulator and other stakeholders to consider proposed revisions to the access arrangement before these come into effect.

#### *Allgas' proposal*

Allgas has proposed that the revised access arrangement will expire on 30 June 2011. The date of submission for the revised access arrangement will be 9 months prior to the expiry of the access arrangement. The revised access arrangement will then commence on 1 July 2011. At the time of expiry, the access arrangement that is current at that time will remain in place until the regulator approves any revisions.

#### *Other jurisdictions*

A five year period of application for gas access arrangements has been universally adopted by Australian jurisdictional regulators.

#### *Submissions from stakeholders*

No comments were made on this issue in submissions.

#### *QCA position*

Allgas' proposed that the revisions and commencement dates for the revised access arrangement meet the Code requirements and are therefore approved.

### **9.4 Trigger Events for a Review of Access Arrangement**

The Authority required that the current access arrangement include a review trigger which would be activated should the actual level of demand exceed the forecasts by a specific amount in any single year. At that time, the Authority was concerned that little information was available to establish whether the demand forecasts were sufficiently robust. Allgas has not proposed a review trigger that could lead to a review of access arrangement in their revised access arrangement (for changes in demand or any other reason). Given that improved information for the purpose of forecasting demand is now available, the Authority does not require a review trigger to be included in the revised access arrangement.

## 10. GENERAL PRINCIPLES FOR DETERMINING REVENUE AND TARIFFS

*The Code sets out a number of general principles against which the Authority is required to assess the reference tariffs proposed in an access arrangement. The Authority has referred to these principles in dealing with particular pricing issues that arise.*

*Allgas has proposed an approach to determining total revenue for services provided under the access arrangement which allows for a rate of return on assets used, depreciation of those assets, and operating and other non-capital costs of providing the service. This is defined in the Code as a ‘cost of service’ approach. The Authority accepts this approach for determining total revenue.*

*The Authority accepts the proposal by Allgas to adopt an approach to price setting that uses a ‘cost of service’ approach to determine annual revenue and a ‘price path’ approach to determine future prices. The approach proposed by Allgas is the same as that in the current access arrangement. The calculation of the reference tariffs, including those relating to the trigger mechanism, is discussed in Chapter 15.*

*Allgas has amended its proposed cost pass-through mechanism to include a materiality threshold as required by the Authority in its Draft Decision. Allgas has also revised its definition of impost and, as a result, the Authority accepts Allgas’ proposed cost pass-through mechanism.*

*The Authority accepts that some of the foreseeable costs associated with the introduction of full retail contestability (FRC) cannot be forecast on a reliable basis at this stage. In recognition that these costs may be significant and would have been considered for inclusion had more detail on the implications of FRC been available, the Authority has decided to pre-qualify these costs for pass-through, subject to an assessment of prudence at the time the costs are known and presented to the Authority. Because of the particular circumstances relating to these costs and the timing of this review and the Government’s announcement of the introduction of full retail contestability, the materiality threshold for cost pass-through will not be applied to these costs.*

*Allgas has amended its revised access arrangement to remove the glide path incentive mechanism, as required by Authority in its Draft Decision. However, Allgas has introduced a new incentive mechanism as a fixed principle in its place. The Authority has not changed its position in relation to incentive mechanisms that are additional to the price path form of regulation, which was discussed in the Draft Decision. Given the inherent incentives that result from the use of a price path mechanism, further incentives are not justified. In addition, there is considerable difficulty in identifying performance due solely to structural change in the gas market and industry, which is at best a vague concept. Consequently, the Authority does not accept Allgas’ proposed fixed principle for an efficiency carry-over mechanism that would result in gains from structural change being retained by Allgas for a period of ten years. Incentive mechanisms, such as that proposed by Allgas, can result in windfall gains accruing to a service provider at the expense of users and prospective users.*

### 10.1 Introduction

Section 8 of the Code sets out a number of general principles for determining total revenue and reference tariffs. In particular, section 8.1 of the Code sets out the principles against which the proposed treatment of total revenue, tariffs and incentive arrangements are to be considered.

The tariff arrangements detailed in an access arrangement are intended to be applicable for the length of a regulatory period. The form of regulation relates to the method for calculating and adjusting tariffs (when applicable) and the treatment of risk throughout the regulatory period.

The form of regulation adopted should seek to achieve an efficient allocation of risk, by allowing the parties in the best position to handle risk to do so.

The Code provides a choice between a ‘price path’ approach and a ‘cost of service’ approach (as defined below), or some mix of these approaches. Neither of these approaches, applied strictly, is likely to be consistent with efficient pricing principles. It is therefore probable that adopting either approach would lead to higher costs to the end user than a mixed approach, which would be likely to allocate risk more efficiently.

## 10.2 Code Requirements

There are four groups of principles contained in the Code. They include general principles that apply to all matters as well as those related specifically to total revenue, tariff variation and incentive mechanisms.

### *General principles*

Under the Code (section 8.1), reference tariff principles are designed to ensure that certain key principles are reflected in the reference tariff policy and in the calculation of all reference tariffs. These general principles include:

- (a) providing the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference service over the expected life of the assets used in delivering that service;
- (b) replicating the outcome of a competitive market;
- (c) ensuring the safe and reliable operation of the pipeline;
- (d) not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries;
- (e) efficiency in the level and structure of the reference tariff; and
- (f) providing an incentive to the service provider to reduce costs and to develop the market for reference and other services.

To the extent that the principles are in conflict in their application to a particular reference tariff determination, the Authority may determine the manner in which they can best be reconciled or which of them should prevail, taking into account section 2.24 of the Code, which states that the Authority must consider a number of broad principles in its assessment of the access arrangement.

Section 8.2 of the Code goes on to set out the factors that the Authority must be satisfied with in approving a reference tariff policy, namely:

- (a) the revenue to be generated from the sales (or forecast sales) of all services over the access arrangement period (the total revenue) is established consistent with the principles and according to one of the methods contained in section 8;
- (b) to the extent that the covered pipeline is used to provide a number of services, that portion of total revenue that a reference tariff is designed to recover (which may be based upon forecasts) is calculated consistent with the principles contained in section 8;

- (c) a reference tariff (which may be based upon forecasts) is designed so that the portion of total revenue to be recovered from a reference service (referred to in paragraph (b)) is recovered from the users of that reference service consistent with the principles contained in section 8;
- (d) incentive mechanisms are incorporated into the reference tariff policy wherever the relevant regulator considers appropriate and such incentive mechanisms are consistent with the principles contained in section 8; and
- (e) any forecasts required in setting the reference tariff represent best estimates arrived at on a reasonable basis.

#### *Total revenue*

Under section 8.4 of the Code, the total revenue should be calculated according to one of three approaches. These approaches are:

- 1) Cost of service: the total revenue is equal to the cost of providing all services (which may include forecast costs), calculated on the basis of:
  - (a) a return (*rate of return*) on the value of the capital assets that form the covered pipeline (*capital base*);
  - (b) depreciation of the capital base (*depreciation*); and
  - (c) the operating, maintenance and other non-capital costs incurred in providing all services provided by the covered pipeline (*non-capital costs*); or
- 2) IRR: the total revenue will provide a forecast internal rate of return (IRR) for the covered pipeline that is consistent with the principles in sections 8.30 and 8.31; or
- 3) NPV: the total revenue will provide a forecast net present value (NPV) for the covered pipeline equal to zero.

#### *Reference tariff variations*

Section 8.3 of the Code provides that, subject to the general principles for reference tariffs set out in sections 8.1 and 8.2 of the Code, the manner in which a reference tariff may vary within an access arrangement period can be nominated by the service provider. For example, a reference tariff may be designed on the basis of:

- (a) a ‘price path’ approach, whereby a series of reference tariffs is determined at the start of the access period (either individually or as a weighted average) to deliver a revenue stream calculated consistent with the principles in section 8, and are not adjusted to account for subsequent events;
- (b) a ‘cost of service’ approach, whereby the tariff is set on the basis of the anticipated costs of providing the reference service and is adjusted yearly in light of actual outcomes (such as sales volumes and actual costs) to ensure that the tariff recovers the actual costs of providing the service; or
- (c) variations or combinations of these approaches.

### *Incentive mechanisms*

Section 8.44 of the Code states that the relevant regulator should consider incentive mechanisms that allow the service provider to retain all, or any share of, returns to the service provider from the sale of the reference service that exceed those expected during the access arrangement period. These higher than expected returns may be retained by the service provider during the access arrangement period (or for a longer period) where the relevant regulator considers it appropriate.

Without limiting alternatives, section 8.45 identifies some of the potential mechanisms through which gains from increased efficiency, innovation or volume of sales may be retained by the service provider.

Section 8.46 lists the objectives that the relevant regulator should consider in considering the incentive mechanisms discussed above. In considering any proposal, the regulator is required to ensure that users and prospective users gain from increased efficiency, innovation and volume of sales (but not necessarily during the access arrangement period in which the gains are made).

## **10.3 Determining Total Revenue**

### *Allgas proposal*

Allgas has proposed a ‘cost of service’ approach to determining total revenue.

### *Other jurisdictions*

A ‘cost of service’ approach to determine total revenue has been widely accepted by other jurisdictional regulators (for example, ICRC (2004), IPART (2005)).

### *Submissions from stakeholders*

No submissions were received in relation to this issue.

### *QCA position*

The Authority accepts Allgas’ proposal to use a ‘cost of service’ approach to calculate total revenue. The Authority notes this approach was used in the current access arrangement, has been widely used in other jurisdictions, and has generally assisted in allowing the components of total revenue to be readily understood by stakeholders.

The detailed calculation of total revenue is discussed in Chapter 15 (Reference Tariffs and Tariffs Paths). This calculation differs in some aspects to that contained in Allgas’ access arrangement information because of the different forecasts of cost and demand accepted by the Authority in determining the revenue requirement.

## **10.4 Tariff Variations**

### *Allgas proposal*

Allgas has proposed a mix of tariff variation approaches for its different reference services.

#### Haulage reference services

Allgas has proposed separate weighted average price paths for reference services applying to demand and volume customers. These weighted average price paths are determined at the beginning of the regulatory period, based on the forecast revenue requirements for the separate demand and volume customer classes for the access arrangement period.

The formula for adjusting the weighted average price path adopts the conventional form of 'CPI-X', whereby prices are adjusted for inflation each year subject to an 'X' factor which smoothes prices over the regulatory period.

Allgas also proposed a side constraint that would limit the size of annual tariff adjustments to individual volume customers.

#### Ancillary services

For ancillary services, such as special meter readings, a price path is proposed that adjusts the reference tariff over the access arrangement period in line with changes in the rate of inflation.

#### Trigger mechanism

Allgas proposed to pass-through imposts that change during the next regulatory period. The imposts that Allgas will apply to the Authority to pass through are those that are unforeseen, uncontrollable and material. If required, a cost pass-through application will be submitted to the Authority one month prior to the commencement of each contract year.

Consistent with the requirements of the Draft Decision, Allgas amended its definition of 'impost' to be:

- a change in taxation or other statutory charges; or
- any other major change in government policy (for example, costs associated with the introduction of full retail contestability).

In addition, Allgas has amended its revised access arrangement to include a materiality threshold for cost pass-through events of 1 per cent of (forecast) annual revenue per event based on the forecast revenue in the year in which the event occurred.

#### *Other jurisdictions*

##### Reference services

Other regulators (for example, ICRC (2004), IPART (2005)) have accepted a mixed tariff-variation approach that include weighted average price paths for customer classes, such as volume customers, as well as a price path approach for individual services, such as special meter readings.

##### Trigger mechanism

IPART (2005) approved a range of pass-through events identified by AGLGN, including those relating to tax, regulatory events and costs of unaccounted for gas. However, IPART disallowed the pass-through of costs relating to mine subsidence, insurance and unforeseen events. These costs were disallowed by IPART because of the potential to reduce the incentive by AGLGN to minimise such risks, for example, by taking steps to mitigate risks and costs.

In accepting AGLGN's cost pass-through mechanism, IPART noted that there is a trade-off within section 8.1 of the Code which requires that, while efficient costs are to be reflected in the Reference Tariff, there is also a need to encourage service providers to reduce costs. Therefore, while IPART accepted the need for the pass-through of efficient costs, it also noted that a materiality threshold that is set too low would reduce the incentive for service providers to reduce costs. AGLGN proposed to limit cost pass-through to material costs but did not propose a specific materiality threshold. IPART accepted AGLGN's proposal, indicating that materiality would be assessed on a case by case basis, taking account of the provisions in the Code.

Envestra and TXU were required by ESCV (2002) to include a materiality restriction to cost pass-through provisions in their access arrangements. The Commission noted that Envestra had proposed a cost pass-through threshold of 0.05 per cent of its annual revenue requirement. However, the Commission did not believe that an explicit threshold was either needed or desirable. Guidelines on what would constitute a material impact were developed subsequent to the approval of the access arrangements.

The ACCC (2003) considered that, for cost pass-through items, the financial impact of the event must be material, with the potential to affect the commercial viability of the business. While a materiality threshold was not defined, the ACCC indicated that the setting of such a threshold would serve to limit the number of cost pass-through applications made.

ESCOSA (2005) indicated that trigger events should be one-off and identifiable exogenous events, not a multitude of small cumulative events. ESCOSA also suggested that such events should trigger symmetrically, that is, pass through both cost increases and decreases.

#### *Submissions from stakeholders*

In its submission on the Draft Decision, the Queensland Government (2006) supported the concept of cost pass-through of reasonable costs incurred by service providers in response to unforeseen events beyond their control. However, the Queensland Government suggested that pass-throughs should be triggered when a pre-determined nominal threshold was exceeded and that this threshold should be negotiated between the Authority and the service provider to provide greater certainty for the affected business.

In addition, the Queensland Government highlighted the imminent introduction of full retail contestability and suggested that any associated costs should be clearly specified as a trigger for a cost pass-through event.

The Energy Users Association of Australia (EUAA) (2006) supported the inclusion of a materiality threshold to limit the extent of cost pass-through to network users. EUAA suggested that:

*'users should not bear the costs of events that were in the control of the service provider, for example, unexpected network amelioration' (EUAA 2006, page 4).*

#### *QCA position*

##### Haulage service tariff variations

The approach proposed by Allgas for the next regulatory period is, in principle, the same as the approach applied during the current regulatory period and, on this basis, the Authority accepts the proposed haulage service tariff variation approach proposed by Allgas.

However, the application of a single weighted average price path to volume customers raises issues in relation to cost reflectivity. Cost (or revenue) allocation between different customer classes and the required formulation of the separate weighted average price paths are discussed in Chapter 15.

#### Ancillary service tariff variations

As the cost of providing ancillary services is largely a labour cost, the Authority accepts that these costs are likely to change over the access arrangement period more or less in line with the rate of inflation. The Authority therefore accepts Allgas' proposal to adjust reference tariffs for ancillary services based on movements in the CPI.

#### Trigger mechanisms

The Authority supports the concept of unforeseen and material changes in costs, which are beyond the control of the service provider, being passed through to consumers within the access period, as this is consistent with what would be expected in a competitive environment. However, the intention is not to protect the service provider from every unforeseen event that may occur during the regulatory period.

It is to be expected that forecast and actual costs will vary both on the upside and the downside during a regulatory period – this is inherent in the price path form of regulation proposed by Allgas and accepted by the Authority. Where an event fails to meet the requirements for cost pass-through within a regulatory period, this does not preclude these costs from being recovered in the future. At the regulatory reset, appropriate costs will be established for the ensuing regulatory period.

However, there are circumstances that warrant acceptance of a cost pass-through. There are two elements to be satisfied in determining whether an event should lead to a cost pass-through. The first element is whether an event is of such an unusual and unexpected nature that the costs could not have been reasonably foreseen at the time the access arrangement was approved. In accepting a cost pass-through mechanism, the regulator should not override the intent of the price path form of regulation which generally results in cost savings/increases being retained/absorbed by the service provider, along with any other variations, until the next regulatory reset.

Unforeseen network upgrades, maintenance and other network activities instituted by the service provider or its customers would not in themselves constitute cost pass-through events. Rather, a pass-through event would be a major exogenous and unforeseen event outside the control of the service provider (which, in some instances, may coincidentally require a network upgrade or increased maintenance).

The second element to be considered in determining whether a cost pass-through is reasonable is the materiality of the costs incurred. The Authority does not consider relatively minor costs should be considered for pass-through. Such an approach is consistent with section 8.1(f) of the Code, which requires the reference tariff policy to encourage service providers to reduce costs.

During the current access arrangement period, Allgas sought and received a cost pass-through for nine separate items that ranged in value from \$26,000 to \$394,000 and totalled just over \$1.3 million over the period. No unforeseen cost savings were returned to users. The Authority considers that costs of the order of \$26,000 are not material and do not need to be passed through immediately.

The Authority considers that setting a materiality threshold is important as it removes the uncertainty that would otherwise surround this issue. In its recent determination for electricity

distribution, the Authority settled on a threshold for consideration of a general cost pass-through of 1 per cent of (forecast) annual revenue per event based on the forecast revenue in the year in which the event occurred. Had this threshold been in place during the current access arrangement period, only the single largest of the nine cost pass-through events affecting Allgas would have met the threshold.

Allgas has adopted the amendments required by the Authority in its Draft Decision with respect to the definition of a cost pass-through and has included a materiality threshold of 1 per cent of (forecast) annual revenue per event based on the forecast revenue in the year in which the event occurred.

### **The Authority accepts Allgas' amended Trigger Mechanism**

In principle, the Authority does not consider that it is practical or appropriate to pre-qualify certain events as accepted pass-through events when, by definition, all such events are either unforeseen or uncertain.

However, the Authority notes the concerns of both Allgas and other stakeholders that the introduction of full retail contestability will result in costs that are foreseeable but remain undefined at this stage. As a forecast of these costs cannot be determined on a reasonable basis at this time, the Authority will accept prudent costs associated with the introduction of full retail contestability on the same basis as a cost pass-through. In this single circumstance, the materiality test will not be imposed. This provision will ensure that Allgas is not unfairly penalised simply due to the coincidence of timing in the introduction of retail contestability and the approval of its future access arrangement.

## **10.5 Incentive Mechanisms**

### *Allgas proposal*

Allgas has amended the incentive mechanisms and related principles in section 3.4 of its revised access arrangement. The incentives include:

- a commitment required of the regulator that it will not adjust total revenue for differences between forecasts and actuals for gas deliveries and/or business costs; and
- a fixed principle that would allow Allgas to retain efficiencies stemming from changes to the gas market or industry for a period of five years and then returned to users over the subsequent five year period using a glide path approach.

### *Other Jurisdictions*

All jurisdictions have accepted some form of incentive mechanism in service providers' access arrangements. However, the approaches vary and have evolved over time.

IPART (2005) accepted an incentive mechanism where gains/losses from cost savings and variations from forecast demand were retained by AGL during the regulatory period. No carry-over mechanism was allowed that would extend beyond the expiry of regulatory period.

In its first review of access arrangements, ESCV (then ORG) accepted inclusion of an efficiency carry-over mechanism. Its key feature was that efficiency gains could be kept by the service provider for a period of 5 years, while efficiency losses were to be treated asymmetrically with a 'zero floor', which meant that accumulated efficiency losses were not carried forward. ESCV (2002) noted data problems in its first assessment of efficiency carry-over for the period 1998-

2002. Nonetheless, ESCV allowed some carry-over for Multinet but disallowed efficiency carry-overs for Envestra Albury and Envestra Victoria. ESCV allowed the continuation of the carry-over mechanism into the revised access arrangement.

However, the ESCV (2002) rejected Envestra's argument that a 'fair sharing' would require the carry-over gains to be retained by the service provider for 10 years. ESCV considered that "the five-year carry-over period provides an incentive for the service provider to reduce costs, whilst at the same time ensuring that efficiency gains are passed through to customers without undue delay."

More recently, in its regulation of electricity distributors, the ESCV (2005) has found further data problems in determining efficiency gains/losses over time, and suggested that; "in hindsight the Commission underestimated the challenges that would present themselves in relying on the reported costs of the distribution businesses". Business restructuring and agreements with related third parties to provide services were noted by the ESCV as major obstacles in the assessment of efficiency gains.

ESCV (2005a) found service quality had been compromised by the incentive to delay spending and investment, an incentive which is strengthened by the inclusion of a carry-over mechanism. In response, ESCV only excluded capex from the carry-over mechanism. The remaining opex carry-over mechanism was clarified so that efficiency changes relative to the benchmarks were treated symmetrically (that is, negative efficiency gains (efficiency losses) are feasible).

ICRC (2004) noted that ActewAGL sought no efficiency carry-over mechanism.

#### *Submissions from stakeholders*

In its submission on the Draft Decision, the Energy Users Association of Australia (EUAA) supported the removal of additional incentives. The EUAA considered that Allgas already has incentives built into its access arrangement and further incentives would be unjustified and detrimental to end users.

#### *QCA position*

As a general principle, the Authority agrees that the form of regulation applied to the gas service providers requires that the regulator support the notion of regulatory certainty whereby forecasts, provided and accepted in good faith, will form the basis of establishing the revenue requirements of the service and that, once established, the Authority will not subsequently seek to make retrospective adjustments in future regulatory periods to recover any difference between actual outcomes over the period and the forecasts accepted at the outset. This principle also requires that the service providers deliver an acceptable quality of service and do not seek to profit by simply failing to invest or undertake necessary maintenance to the detriment of customers. In addition, having had particular expenditure included in one access period, the service provider cannot fail to undertake that expenditure and then seek to have it included again in a subsequent period. There are some exceptions to this principle, which are raised in the relevant sections of this Final Decision and are specifically required to be included in Allgas' revised access arrangement.

The Authority does not accept Allgas' proposed fixed principle for an efficiency carry-over incentive mechanism which provides for the retention across subsequent regulatory periods of efficiencies resulting from structural change to gas markets or the industry. The Authority considers that there are sufficient incentives in the price path mechanism to encourage cost savings, which will be retained by Allgas during the regulatory period. The experience in other jurisdictions (and in other industry sectors in Queensland), where such mechanisms have been

used (or even contemplated), suggests that they encourage an over emphasis on cost cutting which has contributed to underinvestment and deferment of maintenance on the network, with resulting detriment to service quality.

In the event of structural change to gas markets or the industry, Allgas would be free to submit a revised access arrangement to the relevant regulator to take account of the impact of any such changes on Allgas.

**Amendment 10.1**

**For Allgas' access arrangement to be approved, Allgas must remove the fixed principle for an efficiency carry-over mechanism.**

## 11. ROLLING FORWARD THE CAPITAL BASE

*The Code requires the capital base to be determined using a roll-forward approach. There are two roll-forward periods that are of relevance for Allgas' revised access arrangement.*

*The first period is from 1 July 2001 to 30 June 2006, with the roll-forward over this period providing the opening capital base for the next regulatory period. Allgas' capital base as at 1 July 2001 was \$202.6 million. This value has been rolled forward to take account of actual prudent capital expenditure, actual inflation, forecast depreciation, disposals and any redundant assets during the current the period.*

*In its Draft Decision, the Authority largely accepted Allgas' capital expenditure over the current access period as being consistent with the Code. However, the level of non-system capital expenditures in 2004 and 2005 (apparently related to vehicles and IT equipment) was reduced. In response to the Draft Decision, Allgas has satisfied the Authority that most of these expenditures were prudent and therefore meet the requirements of the Code.*

*The Authority has accepted Allgas' disclosed level of capital contributions over the current access period. It has also accepted this figure as a reasonable forecast for capital contributions for the next access period. Because Allgas provided no forecasts of capital contributions at the time of the last review, both the past and forecast capital contributions have been deducted from Allgas' revenues over the next access period. Differences between forecast and actual capital contributions over the next access arrangement period will also be adjusted at the next review.*

*On this basis, the Authority has set Allgas' closing capital base for the current regulatory period (30 June 2006) at \$303.2 million.*

*The second roll-forward covers the next regulatory period and rolls forward the 30 June 2006 value of the capital base to 30 June 2011 using forecasts of capital expenditure, depreciation, inflation and redundant assets.*

*In its Draft Decision, the Authority required Allgas to make various adjustments to the roll-forward calculations for the next access period. The most significant related to the level of forecast capital expenditure. Allgas forecast a total \$162.1 million in capital expenditure over the next access period. The Authority has now accepted a forecast total of \$143.5 million as being consistent with the Code. Despite this reduction, total capital expenditure is still 46.4 per cent higher than the total capital expenditure incurred by Allgas over the current access period.*

*The Authority forecasts that Allgas' closing capital base as at 30 June 2011 will be \$447.2 million.*

### 11.1 Introduction

The Code requires the capital base to be determined using a roll-forward approach. There are two roll-forward periods that are of relevance for Allgas' revised access arrangement.

The first roll-forward period is from 1 July 2001 to 30 June 2006, which provides the opening capital base for the next regulatory period. Allgas' capital base as at 1 July 2001 was \$202.6 million.<sup>3</sup> This value has been rolled forward to take account of actual prudent capital expenditure, actual inflation, forecast depreciation, disposals and removal of any redundant assets during the current the period.

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<sup>3</sup> Refer to the Authority's 2001 Final Decision for discussion on how this valuation was determined.

The second roll-forward period is from 1 July 2006 to 30 June 2011, with the roll-forward calculated in a similar manner, but based on forecasts rather than actual amounts.

## 11.2 Determining the Opening Capital Base at 1 July 2006

### *Code requirements*

Section 8.9 of the Code outlines the process by which the capital base is adjusted at the expiry of an access arrangement period. Sections 8.15 to 8.29 detail the principles to be applied in adjusting the value of the capital base over time as a result of new additions to the capital base and as a result of assets ceasing to be used for the delivery of services.

### *Allgas' proposal*

The calculation of the 1 July 2006 capital base provided by Allgas in its revised access arrangement is detailed below. Figures for 2001-02 to 2004-05 are based on actual information while the figures for 2005-06 are based on revised forecasts.

#### Past capital expenditure

Allgas' capital expenditure significantly exceeded the forecasts included in the current access arrangement. Table 11.1 shows the forecast versus actual capital expenditure for Allgas over the current regulatory period. The "actual" figures for 2005-06 are revised estimates.

**Table 11.1: Allgas actual and forecast capital expenditure, 2001-02 to 2005-06 (\$m, nominal)**

	2001-02	2002-03	2003-04	2004-05	2005-06
Customer requested	5.4	10.7	11.9	11.8	11.5
Augmentation	5.4	0.6	2.1	1.5	8.2
Network renewal	2.4	4.2	4.2	3.9	5.3
<b>System Total</b>	<b>13.2</b>	<b>15.5</b>	<b>18.1</b>	<b>17.2</b>	<b>25.0</b>
Non-system total	0.6	0.6	2.2	2.7	2.9
<b>Total actual capital expenditure</b>	<b>13.7</b>	<b>16.1</b>	<b>20.3</b>	<b>19.9</b>	<b>27.9</b>
<b>Forecast capital expenditure (2001)</b>	<b>13.8</b>	<b>12.5</b>	<b>10.7</b>	<b>11.0</b>	<b>11.2</b>

#### Past capital contributions

Allgas obtained contributions from customers connecting to its network when the future earnings from these customers were not expected to recover the full cost of service delivery. Allgas reported capital contributions of \$0.2 million each year over the current regulatory period.

#### Redundant and disposed assets

As noted in the Authority's Draft Decision, Allgas estimated that some 20 kilometres of mains had been renewed each year in the period from 2001-02 to 2005-06. According to Allgas, the remaining depreciated value of the mains replaced was less than \$5 per metre and that approximately 75 per cent of these mains were used for insertion of new mains. The remaining 25 per cent of mains were no longer used, and Allgas has identified these as redundant capital.

Regarding disposals, the most significant disposal of assets was in 2003-04 when Allgas sold properties (non-system assets) it owned at Woolloongabba and Mansfield for \$2.8 million. Other disposals included minor non-system assets such as motor vehicles and IT equipment that Allgas sold to Energex Limited over the period.

Subsequent to the Draft Decision, Allgas revised upwards its reported capital redundancies and asset disposals for the current regulatory period, as shown in Table 11.2.

**Table 11.2: Allgas capital redundancies and disposals, 2001-02 to 2005-06 (\$m, nominal)**

	2001-02	2002-03	2003-04	2004-05	2005-06
Total redundancies	0.4	0.3	0.4	0.3	0.3
Total disposals	0	0.3	3.1	0.3	0.1

#### Depreciation

Allgas has used the forecast depreciation figures accepted by the Authority in its 2001 Final Decision for rolling forward the capital base.

#### Summary

Table 11.3 shows how Allgas has rolled forward its capital base over the current regulatory period. This table is included in Allgas' access arrangement information as Table 4.10. On this basis, Allgas has forecast a closing asset value of \$303.0 million as at 30 June 2006.

**Table 11.3: Allgas' proposed roll-forward of the capital base, 2001-02 to 2005-06 (\$m, nominal)**

	2001-02	2002-03	2003-04	2004-05	2005-06
Opening assets	202.6	217.1	233.9	252.3	272.9
Less depreciation	4.9	5.2	5.4	5.4	6.0
Less disposals	0.5	0.4	3.1	0.4	0.3
Plus inflation	5.9	6.0	6.0	6.5	8.1
Plus capex	13.7	16.1	20.3	19.9	27.9
<b>Closing assets</b>	<b>217.1</b>	<b>233.9</b>	<b>252.3</b>	<b>272.9</b>	<b>303.0</b>

#### Other jurisdictions

In determining the opening capital base of the next access period, IPART (2005) and ICRC (2004) made adjustments for actual inflation, actual prudent capex (capital expenditure assessed to not be prudent was not included), capital contributions, disposals and redundant capital over the current period. IPART (2005) also required a regulatory asset register to be updated as part of the roll-forward process.

With respect to capital redundancies, neither ICRC (2004) nor IPART (2005) provided direct compensation for the amounts removed from the capital base.

IPART (2005) and ICRC (2004) required forecast depreciation to be used in the roll-forward of the capital base. Both regulators considered it was inappropriate for the businesses to use actual

depreciation over the period, on the basis that the forecast depreciation reflects revenue actually obtained through approved reference tariffs.

However, the previous forecast of depreciation was adjusted for actual inflation (see also ACCC (2002) and ESCV (2002)). This approach ensured that the initial real value of the asset would equal the total depreciation amount (adjusted for inflation). Using forecast depreciation uncorrected for actual inflation would result in either over or under depreciation of the asset (in real terms) which would not be consistent with the requirements of the Code for an asset to be only depreciated once (see section 8.33(d)).

IPART (2005) and ICRC (2004) both subtracted capital contributions from capital expenditure before it was rolled into the capital base.

#### *Submissions from stakeholders*

EUAA (2006) noted that Allgas' past capital expenditure significantly exceeded previous forecasts and was concerned that this indicated either a lack of rigour in forecasting or in the assessment of past capital expenditure.

#### *QCA position*

Past capital expenditure

#### Draft Decision

In preparing its Draft Decision, the Authority engaged Energy Consulting Group (ECG) to review the prudence of capital expenditure over the current regulatory period, 2001-02 to 2005-06. Key findings in this review were that:

- Allgas customer requested expenditure for domestic, small commercial and industrial, and large commercial and industrial customers was found to be prudent and efficient in accordance with the Code;
- as part of its augmentation projects, Allgas carried out phase 1 of its South Coast project. The South Coast project provided additional security of supply and met growth in demand in the south coast area. In addition, Allgas also carried out other augmentations for security of supply purposes, for example, the Toowoomba West project. ECG considered the costs of these projects to be prudent and efficient in accordance with the Code;
- Allgas advised ECG that it had reduced its network renewal program due to the extensive customer driven expansion required. Capital expenditure incurred by Allgas can be divided into three categories:
  - Area renewals – renewal projects in specific areas, for example, Hawthorne, Kangaroo Point and East Brisbane;
  - Other Renewals – ad hoc renewals that have to be carried out for safety reasons; and
  - Other Projects – upgrading projects, for example, odourisation equipment, gate station noise reduction and refurbishment of bridge crossings.

ECG reviewed the justification for expenditure under each of the categories above and considered that the costs were prudent and efficient in accordance with the Code.

ECG also noted that Allgas' actual non-system expenditure was higher than forecast in the 2001 Final Decision. Allgas advised ECG the additional expenditure was for buildings, vehicles and information technology. ECG accepted that Allgas would purchase land, vehicles and IT equipment in its normal course of carrying out its business. However, in the absence of specific details justifying the expenditure, ECG recommended that only expenditure consistent with the forecasts included in the Authority's 2001 Final Decision could be considered prudent at this time.

The Authority considered the information and forecasts presented by Allgas and those provided by ECG. Where past capital expenditure incurred by Allgas was considered by ECG to be prudent, the Authority accepted Allgas' figures.

In the Draft Decision, the Authority accepted provisional amounts to be included in the roll-forward of the capital base given the absence of detail regarding non-system expenditure in 2001-02 and 2004-05 and the unreliability of estimated expenditure in 2002-03 and 2003-04. These provisional amounts were to be removed in the Authority's Final Decision if Allgas failed to provide sufficient evidence to establish that these costs were prudent.

#### Final Decision

In response to the Draft Decision, Allgas submitted an amended version of its revised access arrangement and access arrangement information and also provided a submission in which the issues raised by the Authority in its Draft Decision were addressed.

The Authority engaged ECG to consider the information provided by Allgas, which included:

- an explanation of the methodology used to allocate non-system capital costs from Energex Limited to Allgas;
- a detailed breakdown of non-system capital costs in 2004-05; and
- the identification of physical assets matched to this capital expenditure.

ECG considered that sufficient information had been provided to establish that the non-system costs incurred by Allgas in 2004-05 were prudent. ECG was not able to undertake a similar assessment for other years within the current period, as non-system costs prior to 2004-05 were significantly lower and reflected a different approach to cost allocation that that used by Allgas from 2004-05 onwards.

Having considered the information provided to it by Allgas, ECG concluded that the costs from 2001-02 to 2004-05 had not exceeded a level that it considered to be efficient and in accordance with the Code. In 2005-06, Allgas estimated that costs would increase, if only slightly, but did not satisfy ECG this increase was justified. Therefore, ECG recommended that the efficient costs incurred in 2004-05 should be maintained in real terms.

The Authority notes that the value of past non-system capital expenditure proposed by Allgas and that assessed to be prudent by ECG are extremely close. The Authority has accepted the non-system costs recommended by ECG as Allgas has been unable to justify any additional costs.

Table 11.4 shows the level of capital expenditure that ECG considered prudent.

**Table 11.4: ECG’s recommended capital expenditure, 2001-02 to 2005-06 (\$m, nominal)**

	2001-02	2002-03	2003-04	2004-05	2005-06
Customer Requested	7.50	10.70	11.89	11.80	11.50
Augmentation	3.30	0.60	2.11	1.50	8.20
Network Renewal	2.40	4.20	4.20	3.90	5.30
<b>System Total</b>	<b>13.20</b>	<b>15.50</b>	<b>18.20</b>	<b>17.20</b>	<b>25.00</b>
Non System	0.60	0.60	2.20	2.70	2.80
<b>Total</b>	<b>13.90</b>	<b>16.10</b>	<b>20.30</b>	<b>19.90</b>	<b>27.80</b>
<b>Allgas Total</b>	<b>13.7</b>	<b>16.1</b>	<b>20.3</b>	<b>19.9</b>	<b>27.9</b>

*Numbers may not add due to rounding.*

#### Past capital contributions

Allgas has noted the receipt of capital contributions during the current access period. No forecasts of capital contributions were provided during the approval process for the current access arrangement.

In accounting for capital contributions from customers, these amounts can either be removed from the capital base or the contribution can be subtracted from revenues. Removing capital contributions from the capital base creates an ongoing administrative burden as these assets must be separately identified and managed throughout their productive lives. Unless there is a need to keep track of these contributions, it is far simpler to offset them against revenue and leave the capital base intact.

Had forecasts of capital contributions been provided at the start of the current access period, the Authority would have required that these be deducted from the revenue, for the reasons noted above. To avoid this group of assets having to be separately tracked over their economic lives, in its Draft Decision the Authority proposed that these past capital contributions be offset against revenue in the next access period. This is consistent with the Authority’s preferred approach for handling capital contributions and with Allgas’ proposal for handling these items in the future. The adjustment is included in the calculation of the revenue requirement (see Chapter 15).

#### Redundant and disposed assets

ECG separately estimated the depreciated value of the assets identified by Allgas as redundant to be \$25,000 each year, on average, over the current access arrangement period. Given the accuracy of the data available, ECG considered Allgas’ estimate of \$34,000 each year over the current regulatory period to be reasonable. ECG recommended the residual value of these disused assets should be deducted from the capital base.

The value of non-system asset disposals (excluding the property sales) was estimated by ECG to be \$200,000 each year of the current regulatory period. ECG did not identify any disposals of system assets, such as meters.

The Code requires the Authority to remove the value of redundant capital from the capital base and preserve its value in present value terms so that, should it contribute to the delivery of service at a later date, the asset can be brought back into the capital base at its then current value. As the disused mains identified by Allgas are unlikely to ever make a contribution to service delivery in the future, the Authority does not accept they are redundant capital as envisaged by the Code. Treating these assets as redundant capital would impose a significant administrative burden for assets that are close to immaterial in value and never likely to be used

again. The Authority, therefore, proposes to treat these assets simply as disposals of non-life expired assets.

As the disused and disposed of assets no longer contribute to the delivery of the reference services, the Authority requires these assets to be removed from the capital base for the purpose of calculating reference tariffs. In the Draft Decision, the Authority accepted Allgas' proposal to remove the disused mains from the capital base at their depreciated value. An increase in revenue requirement equal to the depreciated value of these assets over the next access arrangement period will compensate Allgas for the reduction in the capital base. Disposed assets will be removed from the capital base without adjustment to the revenue requirement.

In the Draft Decision, Allgas was requested to provide a detailed breakdown of assets disposed of, or otherwise removed from the capital base. This information is used by the Authority to update the regulatory capital base established at the commencement of the current regulatory period. In March 2006, Allgas provided this information to the Authority in a separate submission. The Allgas regulatory capital base has been adjusted to account for the sale of these assets. However, the Authority has not accepted the higher level of capital redundancies now reported by Allgas as no explanation has been provided to support the higher numbers and ECG had previously endorsed the level of redundancies included in Allgas' original revised access arrangement.

#### Past depreciation

The Code requires that the roll-forward of the capital base be made using forecast depreciation figures included in the 2001 Final Decision, adjusted for inflation, as these represent the funds returned to Allgas over the current access arrangement period. Allgas used forecast depreciation, adjusted for actual inflation, in its roll-forward of the capital base in its initial revised access arrangement. In its Draft Decision, the Authority amended Allgas' calculation of past depreciation. Following further discussion with Allgas, the Authority now understands the reason for Allgas' approach and accepts the original numbers proposed by Allgas which were those included in the 2001 Final Decision.

#### Past inflation

The 2001 Final Decision adopted a constant rate of expected inflation to roll forward the capital base from 2001-02 to 2005-06. However, in arriving at the opening capital base for the next regulatory period, this assumed rate of inflation can be adjusted to reflect actual inflation over the previous period and a revised estimate of inflation in 2005-06, as shown in Table 11.5.

**Table 11.5: Forecast and actual CPI over the current period 2001-02 to 2005-06 (%)**

	2001-02	2002-03	2003-4	2004-05	2005-06
<b>Forecast CPI (2001)</b>	2.50	2.50	2.50	2.50	2.50
<b>Actual CPI</b>	2.84	2.69	2.48	2.49	2.77*

\* Forecast

In the revised access arrangement information submitted in response to the Draft Decision, Allgas has adopted the same actual inflation rates as the Authority for the period 2001-02 to 2005-06.

Table 11.6 shows the roll-forward of the capital base to its closing value on 30 June 2006. This closing figure then becomes the opening value for the next access arrangement period.

**Table 11.6: Roll-forward of Allgas' capital base to 30 June 2006 (\$m, nominal)**

	2001-02	2002-03	2003-04	2004-05	2005-06
Opening assets	202.6	217.6	234.3	252.4	273.2
Less depreciation	4.7	5.1	5.2	5.3	5.6
Less disposals	0.04	0.33	3.14	0.33	0.13
Plus inflation	5.9	6.1	6.0	6.5	8.0
Plus capex	13.8	16.1	20.4	19.9	27.8
<b>Closing assets</b>	<b>217.6</b>	<b>234.3</b>	<b>252.4</b>	<b>273.2</b>	<b>303.2</b>

Numbers may not add due to rounding.

#### **Amendment 11.1**

**In order for Allgas' access arrangement to be approved, Allgas must amend its roll-forward of the capital base for the current period in accordance with Table 11.6.**

### **11.3 Rolling Forward the Capital Base to 30 June 2011**

Once the opening capital base has been established, this value is then rolled forward to the end of the access arrangement period based on forecast capital expenditure, depreciation and inflation. In addition, any assets that are expected to cease to contribute to the delivery of services (disposals and redundant assets) are removed.

#### *Code requirements*

In general, the Authority must establish whether the new facilities investment (capital expenditure) forecasts provided by Allgas represent a best estimate arrived at on a reasonable basis (section 8.2(e) of the Code). The Authority is also required to address specific tests and provisions under sections 8.15-8.22 of the Code to determine the extent to which the service providers' forecasts of capital expenditure comply with these tests and provisions, and hence whether those forecasts should be accepted for the purpose of calculating the reference tariffs for the next access arrangement period.

Section 8.16 of the Code provides that capital expenditure recognised should:

- (a) not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering services; and
- (b) satisfy one of the following conditions:
  - (i) the anticipated incremental revenue generated by the new facility exceeds the new facilities investment; or
  - (ii) the service provider and/or users satisfy the relevant regulator that the new facility has system-wide benefits that, in the relevant regulator's opinion, justify the approval of a higher reference tariff for all users; or
  - (iii) the new facility is necessary to maintain the safety, integrity or contracted capacity of services.

When evaluating forecast capital expenditure against the criteria above, the Authority must also be cognisant of economies of scale and scope in the increments in which capacity can be added and that sufficient capacity exists to meet forecast sales over a reasonable time frame.

Where a given amount of capital expenditure does not meet any of the tests in section 8.16, the portion that would meet these tests may be included in the capital base. There are two options open to the service provider to recover the additional costs that are unable to be included in the capital base (section 8.19). The service provider can:

- levy a surcharge on, or agree a capital contribution with, the relevant user or users; or
- place the excess costs into a speculative investment fund and seek to include them in the capital base in the future if circumstances change and the required criteria are met.

The overall objective of section 8.16 is to ensure that new investment in projects is subject to appropriate tests of economic feasibility and technical suitability before being included in the capital base and thus in the reference tariff. In particular, it is important to ensure that uneconomic investments are not included in the capital base on the basis that part of the cost will simply be imposed on users of the system who do not receive a commensurate benefit from such investment.

#### *Allgas' proposal*

Allgas identified new customer requested connections, network augmentation, network renewal and non-system information technology upgrades as the key drivers of its proposed capital expenditure over the next access arrangement period.

The revised forecast capital expenditure proposed by Allgas is outlined in section 4.4.3 of its access arrangement information and summarised in Table 11.7.

**Table 11.7: Allgas' forecast capital expenditure, 2006-07 to 2010-11 (\$m, nominal)**

	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Customer requested	12.9	14.3	15.9	17.3	20.1
Network augmentation	1.5	2.5	3.0	5.7	0.1
Network renewal	9.4	9.4	9.8	8.2	12.5
Non-system	6.9	3.0	3.1	3.2	3.2
<b>Total</b>	<b>30.7</b>	<b>29.2</b>	<b>31.8</b>	<b>34.5</b>	<b>35.9</b>

*Numbers may not add due to rounding.*

#### Customer requested connections

Allgas advised that it will continue to actively grow its network through green-field expansion to new housing estates. Forecast customer requested capital expenditure is a function of the number of domestic, commercial and industrial customers that Allgas expects to connect in the next access period.

Allgas has forecast capital expenditure on connecting new customers to be \$80.5 million over the next regulatory period. These forecasts are based on continued strong growth in the number of domestic customers, a modest increase in the number of small commercial and industrial customers and one new large customer each year of the next access arrangement period.

### Network augmentation

Allgas' proposed augmentation expenditure, which provides for 37.95 km of new mains, includes:

- The South Coast Stage 2 project in 2008-09 and 2009-10 with the construction of 10.2 km of 200 mm steel pipeline from Browns Plains to Logan Reserve at an estimated cost of \$5.88 million;
- The Ekibin augmentation project in 2007-08 for the construction of 3.55 km of 150 mm steel main at an estimated cost of \$1.31 million. Allgas advised that this project will reduce the possible risk associated with future higher pressure operation of the Runcorn high pressure system, provide emergency supply and provide options for new supply points to facilitate renewal projects; and
- Five specific, and various other, projects providing 24.2 km of mains forecast to cost a total of \$4.35 million.

### Network renewal

Allgas proposed to accelerate its past rate of network renewal and remove all cast iron and unprotected steel gas mains from its network by 2015. Allgas advised that the drivers for this program were to reduce unaccounted for gas (UAG) and provide sufficient capacity for new customer loads as modern gas appliances, such as new instantaneous gas water heaters, cannot be supported by the older low pressure network. However, in its amended version of its revised access arrangement, Allgas noted that it had curtailed somewhat the expansion of the network program.

While Allgas has so far replaced around 20 km of mains on average over each year of the current access arrangement period, it expects to replace 30 km of mains in 2005-06, the final year of the current period. Allgas has proposed to increase its rate of network renewal to 65 km each year, on average, over the next access arrangement period (compared to 86 km each year in Allgas' original revised access arrangement). According to Allgas, this rate of network renewal will result in all old low pressure mains being replaced within eight to nine years (compared to five previously).

Allgas also included forecast expenditure of \$2.86 million for 'other renewals' over the next regulatory period. This expenditure relates to unplanned renewals driven primarily by public reports of gas leakage that result in Allgas repairing or replacing sections of main in accordance with relevant legislation.

### Non-system upgrades

Allgas has forecast non-system capital expenditure for IT equipment and customer support systems in order to comply with a range of new network safety, security and market operation requirements. According to Allgas, the introduction of full retail contestability from 1 July 2007 has also increased the need for improved information management to meet the anticipated increase in the number of customers that may shift between natural gas retailers (currently restricted to those above 1 TJ).

Allgas amended its revised access arrangement to include a substantial increase in non-system capital expenditure. The increase relates to a higher estimate for the proposed new IT equipment as well as costs relating to the vehicles, specialised tools, furniture and buildings. Allgas indicated the revised forecast is consistent with the cost allocation method approved by the Authority for 2004-05. Overall, Allgas' forecast cost of non-system capital expenditure has

been revised to \$19.3 million over the next regulatory period (compared to \$6.5 million previously included in the revised access arrangement).

#### Summary

**Table 11.8: Allgas’ proposed roll-forward the capital base, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Opening assets	303.0	335.4	365.5	397.9	433.0
Less depreciation	7.9	8.7	9.7	10.7	11.8
Less disposals	0	0	0	0	0
Plus inflation	8.7	9.6	10.4	11.4	12.3
Plus capex	30.7	29.2	31.7	34.5	35.9
<b>Closing assets</b>	<b>335.4</b>	<b>365.5</b>	<b>397.9</b>	<b>433.0</b>	<b>469.5</b>

#### *Other jurisdictions*

Regulators have frequently considered that proposed access arrangements have provided insufficient support for expenditure forecasts in terms of the requirements set out in section 8.16 of the Code. In these circumstances, additional information has been required from the service providers with a view to establishing compliance with the Code. In other cases, regulators have required downward adjustments to capital expenditure forecasts (for example, IPART (2005)).

#### *Submissions from stakeholders*

EUAA (2006) supported the Authority’s decision to reduce the forecast cost of industrial and commercial customer connection costs proposed by Allgas.

The Queensland Government (2006) noted that its ‘Sustainable Housing Policy’ would result in an increase in the demand for instantaneous gas hot water heaters. In particular, the Queensland Government suggested that the mains replacement programs proposed by the service providers would be necessary in older areas, particularly some parts of Brisbane, in order to replace lower pressure mains to enable instantaneous gas hot water systems to work effectively. The Queensland Government urged the Authority to ensure that the service providers had capacity for sufficient capital expenditure to enable the timely upgrade of infrastructure to support Government policies.

#### *QCA position*

To assist the Authority in forming its opinion regarding the Code compliance of Allgas’ forecast capital expenditure, ECG was commissioned to undertake a detailed assessment of the forecast capital expenditure, with specific reference to the technical prudence aspects of the Code’s requirements. ECG reviewed the efficiency and sufficiency of the proposed capital expenditure, safety and service requirements and the reasonableness of growth related investment in the context of good asset management practices.

An initial assessment was made by ECG in relation to the revised access arrangement submitted by Allgas in September 2005. A further assessment was prepared in April 2006 to consider the

amended version of Allgas' revised access arrangement and the additional information provided by Allgas.

In its initial assessment, ECG noted that Allgas' forecast capital expenditure represented a significant increase compared with the current period. The most significant increases forecast by Allgas related to customer requested expenditure, network renewal expenditure and non-system capital expenditure.

Based on its further analysis, ECG recommended forecast capital expenditure for Allgas as shown in Table 11.9 below.

**Table 11.9: ECG forecast capital expenditure for Allgas, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Customer requested	12.81	14.10	15.56	16.82	19.40
Augmentation	1.49	2.46	2.94	5.54	0.09
Network renewal	6.52	6.51	6.59	6.66	6.73
Non-system	6.90	2.98	3.06	3.15	3.23
<b>ECG Total</b>	<b>27.72</b>	<b>26.05</b>	<b>28.15</b>	<b>32.17</b>	<b>29.45</b>
<b>Allgas Total</b>	<b>30.7</b>	<b>29.2</b>	<b>31.8</b>	<b>34.5</b>	<b>35.9</b>

*Numbers may not add due to rounding.*

Customer requested

#### Draft Decision

In its Draft decision, the Authority noted that Allgas had undertaken significantly more customer connections than anticipated at the time of the last review. The domestic connection forecasts therefore appeared consistent with this past trend.

However, Allgas proposed a connection cost of \$3,120 per domestic customer (based on a forecast 15,504 new domestic connections), which appeared high when compared to service providers in other jurisdictions. According to ECG, the forecast connection cost for AGLGN in NSW was about \$1,400 per customer, for CEG in Wagga it was around \$2,875 per customer and for ActewAGL in Canberra it was about \$1,500 per customer.

ECG recommended, based on its previous work, that the connection cost including overheads should include the following:

- extension mains with 27.9 metres per customer as calculated from Allgas data, including 7.3 metres of headworks and 20.6 metres of internal reticulation;
- extension mains with a unit price of \$60 per metre. This unit price was estimated for the extension mains composition defined above;
- meters with a unit price of \$180 per customer; and
- services with an average unit price of \$770 per customer, based on Allgas information that over 96 per cent of new customers are forecast to be located in new estates.

This yields an average connection cost of \$2,630 per domestic customer, \$490 less than that proposed by Allgas.

In its Draft Decision, the Authority accepted ECG's recommendation that the cost of domestic customer connection be reduced by \$490, to \$2,630 per domestic customer.

Allgas has forecast an average connection cost for commercial and industrial customers of \$18,500 (based on Allgas' forecast that the unit length of new mains required to supply them is about 90 metres per customer). In assessing this forecast, ECG considered the costs for small and large industrial and commercial customers separately.

ECG noted that for small industrial and commercial customers the average connection cost of \$18,500 was significantly more than the \$13,500 per customer estimated for the years 2004-05 and 2005-06 and that the mains unit length proposed by Allgas was significantly more than the 65 metres per customer estimated for those years. Allgas was unable to provide any reason why these measures were likely to change in the future and ECG therefore recommended that the Authority apply the lower cost. In the absence of any evidence to support the higher cost proposed by Allgas, the Authority accepted ECG's recommendation.

The Authority accepted Allgas' forecast of one additional large customer each year until 2011 (see chapter 14). It was expected that new customers, mainly in the Gold Coast region, will be offset by disconnections elsewhere. The Authority accepted the connection cost for this type of customer can be much higher than for small commercial and industrial customers. In the absence of further information, the Authority adopted ECG's estimate of connection cost of \$280,000 per customer for this category of customer. This figure was based on actual expenditures in years 2002-03 to 2004-05.

### Final Decision

ECG reconsidered Allgas' forecasts cost for customer requested connections in relation to domestic customers and commercial and industrial customers in the light of further information provided by Allgas.

With respect to domestic customers, Allgas acknowledged the forecast unit costs were relatively high, as ECG had noted. In further examining the individual components of domestic customer connection costs, ECG noted that the average unit costs were inflated by the headwork costs associated with a number of new developments. While the component cost of customer requested connections were consistent with those expected by ECG in its previous assessment, the overall costs would be higher as a result of the extent of headworks over the next regulatory period. Consequently, ECG revised its assessment of customer request costs and considered the forecast costs to be prudent.

In its initial assessment of connection costs for commercial and industrial customers, ECG had made no allowance for a small number of high cost connections for large customers. After including the cost of connection for twenty large commercial and industrial customers, ECG acknowledged that the Allgas forecast cost was consistent with a prudent service provider acting efficiently.

On the basis of the advice now provided by ECG, the Authority accepts the forecast cost of customer requested connections by Allgas over the next regulatory period.

### Augmentation

ECG's analysis of past capital expenditure considered phase 1 of the South Coast project to be prudent and the unit cost to be efficient. Phase 2, which is scheduled to occur in the next access period, has been justified on the same basis as phase 1 and the unit costs for phase 2 are the same as for Stage 1.

As a case study, ECG reviewed the justification for the Ekibin augmentation proposal. ECG found the unit costs for this project were similar to other projects it had reviewed in the past and found the costs to be within a range that would be considered prudent.

ECG considered Allgas forecast expenditure for both major projects to be prudent and efficient in accordance with the Code.

ECG suggested that a prudent network service provider would make provision to carry out a range of augmentation projects of a minor nature as compared to the South Coast project and the Ekibin project. While Allgas provided limited information related to projects in this category, ECG felt that the expenditure level was approximately the same as in the current period and the unit cost was within an acceptable range for these types of projects. ECG therefore recommended the Authority accept Allgas' forecasts.

The Authority remains satisfied that the augmentation work and the associated costs forecast by Allgas, which were accepted in the Draft Decision, are reasonable based on analysis undertaken by ECG.

Network renewal

#### Draft Decision

According to ECG, network operators in other jurisdictions are replacing cast iron and other old mains over a twenty to forty year period and that, typically, network renewal programs are carried out on the basis that the highest priority is given to the areas which have the highest leakage rates. ECG considered the high UAG costs in Allgas' network justified an accelerated program. However, ECG suggested that targeted replacement of the worst parts of the network will significantly reduce the UAG and allow Allgas to adopt a less aggressive total renewal program.

ECG also suggested that the lack of suitably skilled labour to carry out the renewal work in such a short period may constrain Allgas' ability to complete the proposed renewal work. ECG indicated that options to contract interstate resources to undertake this work may also be limited given network renewals occurring in other States. Given these considerations, ECG recommended that a prudent renewal program would occur over 10 years, rather than 5 years as proposed by Allgas.

ECG advised that the unit cost of \$133 per metre of main for area renewals calculated for the forecast period represented a 15 per cent real increase on the unit cost for the current period. ECG noted that there were increased material costs and tighter local government/regulatory conditions affecting construction costs which have had the effect of increasing the real unit cost of mains renewal. On this basis, ECG considered the proposed unit cost of \$133 per metre to be efficient.

Regarding 'other renewals' (that is, non-area renewals), ECG calculated the forecast expenditure on other mains renewals averaged \$0.6 million each year compared with about \$1.8 million each year accepted by the Authority in its 2001 Final Decision. This implied a proposed 'other renewals' rate of about 3 km each year for the forecast period.

'Other renewals' are primarily driven by reported gas leaks from the public or leakage surveys and are typically small one-off renewal projects. ECG considered the proposed reduction in the 'other renewals' rate was consistent with reducing the repair rate for minor leaks while providing for renewals needed to repair leaks for safety reasons.

Allgas cited reasons, other than reducing UAG, as driving its proposed renewals program. These included the need to provide gas at pressures required for modern gas appliances and to maximise hot water uptake in inner city housing redevelopments. However, the Authority is concerned about the capacity of Allgas to undertake the proposed renewals programs in the timeframe proposed. That service providers in other jurisdictions appear to be taking a much more conservative approach to main replacement also raises some concerns.

For these reasons, the Authority proposes to accept the renewals timeframe suggested by ECG. This renewal program should allow over 40 km of cast iron and unprotected steel mains to be replaced each year. This represents a significant increase on the 20 km replaced each year during the current regulatory period.

The Authority has accepted the ‘other renewals’ capital expenditure proposed by Allgas given ECG’s support for this proposal.

### Final Decision

The issue in contention in relation to renewals is the rate at which Allgas proposes to replace its older low pressure network. All other issues, such as unit costs and other renewal projects, were resolved at the time of the Draft Decision.

ECG noted that Allgas had revised its proposal to complete its network renewal program within eight years rather than five years as previously proposed. From ECG’s perspective, the difference between an eight year program and a ten year program, as it had suggested, is largely subjective. However, ECG suggested that Allgas’ planning capabilities were not sufficiently robust to be able to demonstrate on a sound financial basis the merits of an eight year program compared to a ten year program.

In its submission on the Draft Decision, Allgas suggested that ECG had not adequately addressed the implications of the Queensland Government’s ‘Sustainable Building Code’ which came into effect on 1 March 2006 and requires new homes to have a gas, heat pump or solar hot water heater. In reconsidering this issue, ECG has estimated that only around 4 per cent of new customers come from areas where renewals take place, that is, older more established suburbs near the centre of Brisbane.

Having considered the additional information provided by Allgas, ECG reaffirmed its previous recommendation that completion of the renewal program over the next ten years would be consistent with the requirements of the Code.

The Authority accepts ECG’s recommendation for a ten year mains replacement program as being consistent with a prudent service provider acting efficiently.

Non-system

### Draft Decision

ECG advised that Allgas has only commenced preparing its IT system architecture plan and that, as such, the scope of any major IT project is still unknown and ECG was therefore unable to comment on whether the non-system expenditure proposed by Allgas was prudent or efficient. ECG therefore was only able to recommend an annual expenditure of \$0.3 million each year for non-system related expenditure which is consistent with the costs accepted in the current regulatory period.

The Authority acknowledged that Allgas was likely to require an upgrade to its IT system at some point during the next access period with the onset of full retail contestability (amongst

other reasons). As some additional level of expenditure appears to be justified, the Authority made provision for 50 per cent of the non-system costs sought by Allgas in 2006-07 in its Draft Decision rather than simply removing this item due to the lack of supporting information. However, Allgas was required to clearly demonstrate the justification for this investment prior to the Authority making its Final Decision. Otherwise, this expenditure would be removed and treated on a cost pass-through basis in the next access period, when there would be greater certainty as to the scope and cost of the systems in question.

The Authority accepted ECG's recommendation of a base amount of \$0.3 million non-system capital expenditure in each year for the remaining years of the next access period, as this reflected the cost incurred over the current access arrangement period.

### Final Decision

Allgas' forecast expenditure on a major IT equipment upgrade was not supported by ECG in its initial report, on the basis that insufficient information had been provided by Allgas for this expenditure. Subsequently, ECG has reconsidered the forecast cost of the IT equipment in the light of further information from Allgas. ECG noted that Service Essentials, a subsidiary of Energex, carried out a closed tender with software vendors capable of meeting the requirements of the Australian Electricity and Gas Market. The result of this tender was the identification of 'Peace' as the system that would best meet the needs of Energex Retail, Ergon Energy Retail, Energex Network Electricity and Allgas. From the total cost of \$9.5 million, an allocated cost to Allgas of \$4.2 million has been estimated by Allgas.

ECG assessed the intended scope and business case for the Peace system. The new IT system was expected to address a number of the ring-fencing compliance concerns raised by the Authority in relation to the current information management system, including the ability of the existing system to ensure commercial data is segregated from retail areas of Energex. ECG was of the view that Peace was an appropriate investment for Allgas, despite its cost and complexity, as the market rules and billing requirements that will apply under full retail contestability will require a sophisticated information management system. ECG noted that distributors in other States have adopted similar systems to Peace, such as SPL and Hansen, which are considered to be similar in terms of both cost and functionality. ECG accepted the forecast cost of the Peace system. The Authority acknowledges that Allgas will be required to replace its existing information management system and, having considered the allocation method used by Allgas to justify this apportionment, accepts this forecast cost.

Allgas substantially revised its forecast of other non-system capital expenditure in its revised access arrangement submitted in February 2006. These other items were not included in the revised access arrangement submitted by Allgas in September 2005. As noted in the earlier section on the roll-forward to 1 July 2006, ECG found Allgas' revised non-system capital costs in 2004-05 were justified. Accordingly, ECG has recommended higher forecast non-system capital expenditure over the next regulatory period in relation to vehicles, buildings, furniture and specialised equipment purchases. On the basis of ECG's recommendation, the Authority accepts the forecast costs for these other items.

## Summary

**Table 11.10: Forecast capital expenditure, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Customer requested	12.81	14.10	15.56	16.82	19.40
Augmentation	1.49	2.46	2.94	5.54	0.09
Network renewal	6.52	6.51	6.59	6.66	6.73
Non-system	6.90	2.98	3.06	3.15	3.23
<b>Total</b>	<b>27.72</b>	<b>26.05</b>	<b>28.15</b>	<b>32.17</b>	<b>29.45</b>
<b>ECG total</b>	<b>27.72</b>	<b>26.05</b>	<b>28.15</b>	<b>32.17</b>	<b>29.45</b>
<b>Allgas total</b>	<b>30.7</b>	<b>29.2</b>	<b>31.8</b>	<b>34.5</b>	<b>35.9</b>

Numbers may not add due to rounding.

**Amendment 11.2**

**In order for Allgas' access arrangement to be approved, Allgas must amend its forecast capital expenditure for the five years of the next access arrangement period in accordance with Table 11.10.**

**11.4 Redundant Capital***Code requirements*

The Code provides (section 8.27) that a reference tariff policy may include (and the relevant regulator may require that it include) a mechanism that will, with effect from the commencement of the next access arrangement period, remove an amount from the capital base for a covered pipeline so as to:

- ensure that assets which cease to contribute in any way to the delivery of services are not reflected in the capital base; and
- share costs associated with a decline in the volume of sales of services provided by means of the covered pipeline between the service provider and users.

Before approving a reference tariff which includes such a mechanism, the relevant regulator must take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have on the service provider, users and prospective users. If a reference tariff does include such a mechanism, the determination of the rate of return (under sections 8.30 and 8.31) and the economic life of the assets (under section 8.33) should take account of the resulting risk (and cost) to the service provider of a fall in the revenue received from sales of services provided by means of the covered pipeline or part of the covered pipeline.

Section 8.28 provides that, if assets that are the subject of redundant capital subsequently contribute, or make an enhanced contribution, to the delivery of services, the assets may be treated as a new facility having new facilities investment (for the purpose of sections 8.16, 8.17, 8.18 and 8.19) equal to the redundant capital value increased annually on a compounded basis by the rate of return from the time the redundant capital value was removed from the capital base.

Under section 8.29, a reference tariff policy may include (and the relevant regulator may require it to include) other mechanisms that have the same effect on reference tariffs as the above but which do not result in the removal of any amount from the capital base.

#### *Allgas' proposal*

Allgas has proposed that its capital base shall be reduced on the following principles:

- any assets that cease to contribute to the delivery of services to users shall be removed from the capital base; and
- cost associated with a decline in the volume of sales of services provided by means of the covered pipeline will be shared between Allgas and users.

If assets that are the subject of redundant capital subsequently contribute, or make an enhanced contribution, to the delivery of services, the assets may be treated as a new facility having new facilities investment equal to the value of the redundant capital increased annually on a compounded basis by the rate of return from the time the redundant capital was removed from the capital base.

#### *Other jurisdictions*

Generally, service providers in other jurisdictions have given effect to the redundant capital provisions by inserting the relevant provisions of section 8.27 of the Code directly into the access arrangement, either voluntarily or at the direction of the relevant regulator (see IPART (2005), ICRC (2004)).

#### *Submissions from stakeholders*

No submissions were received on this matter.

#### *QCA position*

The Allgas proposal is similar to that approved by the Authority in the current access arrangement. The difference is that Allgas has removed the separate requirement for assets which are disposed of to be removed from the capital base.

The Authority considers that assets that have been sold or otherwise disposed of can no longer contribute to the delivery of reference services and would therefore be covered by the capital redundancy policy proposed by Allgas. The Authority accepts that Allgas' capital redundancy policy is consistent with the Code.

### **11.5 Forecast Depreciation**

Depreciation is inextricably linked with asset valuation, the treatment of maintenance expenditure and the allowed return on an entity's capital base. This is because:

- the capital base provides the basis or starting value from which the asset is to be depreciated. That is, depreciation can be considered as the difference between the value of an asset at the commencement of a period and its value at the end of a period (assuming no indexation of the capital base);

- maintenance expenditure can affect the rate of depreciation as it affects the rate at which an asset wears out. An asset that is well maintained will generally decline in value more slowly than one which is not maintained to the same level; and
- the return on the entity's capital base relates to the undepreciated value of the asset (that is, that part of the value of the asset that has not already been returned to the owner through depreciation charges).

Accordingly, depreciation calculations will form an important element of the determination of regulatory prices.

#### *Code requirements*

The Code contains different depreciation provisions depending on whether the total revenue calculation, as stipulated in the determination of total revenue, is based on the cost of service, the internal rate of return (IRR) or the net present value (NPV) approach.

Section 8.33 of the Code states that the depreciation schedule should be designed:

- (a) so as to result in the reference tariff changing over time in a manner that is consistent with the efficient growth of the market for the services provided by the pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of the reference tariffs has assumed significant market growth and the pipeline has been sized accordingly);
- (b) so that each asset or group of assets that form part of the covered pipeline is depreciated over the economic life of that asset or group of assets;
- (c) so that, to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the covered pipeline is adjusted over the life of that asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and
- (d) subject to the capital redundancy provision (section 8.27), so that an asset is depreciated only once (that is, so that the sum of the depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the capital base, subject to such adjustment for inflation (if any) as is appropriate given the approach to inflation adopted).

Section 8.34 of the Code translates certain detailed principles into a form that is applicable where the IRR or NPV methodology for determining total revenue is used, and draws a distinction between assets that were in existence at the commencement of the access arrangement period and those new facilities installed during the access arrangement period.

#### *Allgas' proposal*

Allgas has proposed (section 4.3.3 of the access arrangement information) to utilise a straight-line approach in the determination of depreciation for the capital base. Allgas argued that the straight-line approach to depreciation was appropriate since:

- depreciation was allocated according to the expectation of the assets usage over the economic life of the assets;

- depreciation was stable over the life of the assets and therefore would not result in price shocks;
- it was simple, transparent and readily determined; and
- it was widely used and accepted throughout the gas industry and other regulated industries.

Allgas' forecast depreciation was determined by:

- taking the base year (2001-02) depreciation and escalating it for asset indexation as appropriate;
- calculating the depreciation associated with Allgas' additional capital expenditure from 2001-02 to 2005-06 using a straight-line approach;
- calculating the depreciation associated with Allgas' new capital expenditure from 2006-07 to 2010-11 using a straight-line approach; and
- summing these figures to produce a forecast for depreciation over the next 5 year period.

Allgas' resulting annual depreciation forecasts are as shown in Table 11.11.

**Table 11.11: Allgas' forecast depreciation, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Depreciation	7.9	8.7	9.7	10.7	11.8

#### *Other jurisdictions*

IPART (2005) made the following key findings regarding AGLGN's proposed depreciation charges over the next access period:

- IPART accepted the straight line depreciation method used to derive the proposed depreciation met the Code requirements; and
- IPART considered retrospective changes to the lives of assets did not meet the Code requirements.

#### *Submissions from stakeholders*

No submissions were received on this matter.

#### *QCA position*

The forms of depreciation and their relative merits were discussed at length in the Authority's 2001 Final Decision. The Authority accepted Allgas' straight-line approach at that time. Allgas proposes to continue with the same approach.

Straight-line depreciation determines the capital consumption charge for any given period by dividing the net value of the asset (actual cost less the estimated salvage value) by its expected

life. The straight-line method therefore allocates an equal amount of depreciation each year until the asset has been written down to its estimated scrap value at the end of its useful life.

This approach is simple, well understood and transparent. Where the consumption of the service potential of assets is similar through time, or where the deterioration of assets is time related, this approach is a reasonable method for allocating depreciation. However, where consumption is not consistent between years, or where the deterioration of the asset is due to circumstances other than time, alternative methods may be more appropriate.

The Authority therefore accepts Allgas' proposed approach to depreciation.

However, due to differences between Allgas and the Authority on matters such as expected inflation and forecast capital expenditure, the Authority has recalculated Allgas' forecast depreciation. Table 11.12 shows the forecast depreciation for Allgas based on a straight line method. For system assets, the Authority has used the asset lives provided by Allgas in response to the Draft Decision, rather than the weighted average life used in the Draft Decision. For non-system assets, the Authority has used a 5 year life for IT and other equipment and a 10 year life for furniture and vehicles.

**Table 11.12: Forecast depreciation, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Forecast	8.1	9.5	10.4	11.4	11.9

### **Amendment 11.3**

**In order for Allgas' access arrangement to be approved, Allgas must amend its depreciation charges for the five years of the access arrangement period must be amended in accordance with Table 11.12.**

## **11.6 Forecast Working Capital**

### *Allgas' proposal*

In the revised access arrangement initially proposed by Allgas, the forecast cost of working capital was included. Allgas used the following assumptions about payment cycles and inventories in calculating its forecasts:

- debtors at 30 days of annual revenue (pre working capital and tax);
- creditors at 30 days of annual capital and operating expenditure; and
- an estimate of inventories for each financial year to 2010-11 based on historic levels of inventory from the previous access period.

Allgas calculated the return on working capital by multiplying its rate of return (8.75 per cent) by the forecast net working capital requirement, which is equal to the value of inventories plus the average difference between accounts payable and accounts receivable.

In response to the Draft Decision, Allgas removed its claim for working capital from its revised access arrangement.

### *Other jurisdictions*

IPART (2005) allowed AGLGN to include a working capital allowance. However, it required changes in AGLGN methodology, including the use of a 9.7 per cent rate of return (nominal pre-tax).

In contrast, ICRC (2004) did not include a working capital allowance for ActewAGL. They considered ActewAGL had not demonstrated that the methodology used to calculate reference tariffs required a working capital allowance.

In other regulatory decisions, the building blocks approach was found to provide an inherent cash flow benefit, which more than compensated service providers for the working capital costs (see ACCC (2003), ESCV (2000), and ESCOSA (2005)).

### *QCA position*

#### Draft Decision

In the 2001, the Authority included inventories held by Allgas of \$100,000 in the capital base. That base value of inventories has been indexed over the current regulatory period. This approach will continue into the future.

Given inventories have been rolled into the capital base, and in the absence of any information to suggest that the level of inventories has changed, the indexed amount for inventories allowed at the last determination will be retained. There is no need to consider any adjustment to existing practices in respect of the inventory component of working capital. By the start of the next access arrangement period, the value of inventories already built into the capital base will have increased to \$109,000.

The issue of the components of working capital was discussed at length in the Authority's Final Determination for electricity distributors in 2005. In that Determination, the Authority accepted that there may be cash flow timing differences in respect of operating costs, in that cash operating payments may be required to be made before cash receipts are recovered, thus creating a potential working capital requirement for the distributors.

However, consistent with the findings of the ACCC (2003) the ESCV (2000), the ICRC (2004) and ESCOSA (2005), the Authority determined that the revenue formula adopted by the Authority more than compensates the distributors for the cost of financing capital-related costs, thus providing a cash flow advantage. The Authority therefore restricted working capital to the value of inventories.

For the same reason, the Authority did not accept Allgas' proposal to include the difference between accounts receivable and accounts payable in working capital in its Draft Decision

#### Final Decision

The Authority accepts Allgas' response to the Draft Decision as Allgas has removed the cost of working capital in its revised access arrangement, as required.

## **11.7 Expected Inflation**

An expected rate of inflation was used in the current access arrangement period. The expected inflation rate was determined to be 2.5 per cent. Differences between the expected rate of inflation and that actually occurring in the period were reconciled in the current review process

(see section 11.2). For the next regulatory period, an expected rate of inflation will again be required to determine the nominal value of forecasts.

#### *Allgas' proposal*

In its amended revised access arrangement, Allgas has adopted the inflation rate forecasts adopted by the Authority in its Draft Decision.

#### *QCA position*

For this Final Decision, the Authority proposes to use an expected rate of inflation of 2.77 per cent over the revised access arrangement period, as used in the Authority's Draft Decision. This rate is based on the difference between the 10 year Commonwealth bond rate and a similar duration indexed bond rate, averaged over the 20 days up to and including 29 September 2005. Further detail on the approach used to arrive at this expected inflation rate can be found in chapter 12.

### **11.8 Roll-forward of the Capital Base from 2006-07 to 2010-11**

Table 11.14 summarises the discussion in this chapter with respect to capital expenditure, redundant capital, disposals, and depreciation. In addition, an indexation component has been included to increase the value of the capital base each year by the expected inflation level (2.77 per cent).

**Table 11.14: Roll-forward of the capital base, 2006-07 to 2010-11 (\$m, nominal)**

	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Opening assets	303.2	331.6	357.7	385.7	417.7
Plus capex	27.7	26.1	28.2	32.2	29.5
Less disposals	0.0	0.0	0.0	0.0	0.0
Plus inflation	8.8	9.5	10.3	11.1	12.0
Less depreciation	8.1	9.5	10.4	11.4	11.9
Closing assets	<b>331.6</b>	<b>357.7</b>	<b>385.7</b>	<b>417.7</b>	<b>447.2</b>

*Numbers may not add due to rounding.*

#### **Amendment 11.6**

**In order for Allgas' access arrangement to be approved, Allgas must amend its roll-forward of the capital base for the five years of the access arrangement period in accordance with Table 11.14.**

## 12. RATE OF RETURN

*The Authority has estimated the rate of return to be used for the purpose of determining each service provider's reference tariff using a Weighted Average Cost of Capital (WACC)/Capital Asset Pricing Model (CAPM) framework.*

*The individual parameter estimates used by the Authority to arrive at its estimate of the WACC are as follows:*

<i>Risk-free rate (%)</i>	<i>5.25</i>
<i>Market risk premium (%)</i>	<i>6.00</i>
<i>Debt margin (%)</i>	<i>1.425</i>
<i>Debt beta</i>	<i>0.12</i>
<i>Asset Beta</i>	<i>0.55</i>
<i>Equity beta</i>	<i>1.10</i>
<i>Gamma</i>	<i>0.50</i>
<i>Expected inflation (%)</i>	<i>2.77</i>
<i>Nominal post-tax cost of equity (%)</i>	<i>11.25</i>
<i>Nominal post-tax WACC (%)</i>	<i>8.75</i>

*In the Draft Decision, the Authority accepted the WACC of 8.75 per cent that was proposed by Allgas. The Authority has not revisited this issue.*

### 12.1 Introduction

Having arrived at a value for the regulated asset base, the application of an appropriate rate of return to these assets provides the first of the building blocks to be set.

The Authority recently reviewed its methodology for determining the cost of capital, as part of its assessment of the draft access undertaking for the Dalrymple Bay Coal Terminal (DBCT). The Authority's review was informed by a report prepared by Dr Martin Lally of Victoria University (Wellington, New Zealand). The review involved an extensive process of public consultation.

As a result of this review, the Authority has made some changes to its previous approach. By their nature, the changes are non-specific technical matters of methodology – none require a consideration of industry or business-specific factors such as those relating to the particular circumstances of the service providers.

Given the recent nature of this review and the need for regulatory consistency in the Authority's decisions, the Authority's revised approach will apply to this review unless otherwise stated.

The Authority's draft DBCT decision (QCA 2004b) contains a full explanation of the issues. While the changes of approach are generic, the value of certain parameters will be determined by the service provider's particular circumstances. These issues are fully discussed in the relevant sections.

## 12.2 Code Requirements

The Code (sections 8.30 and 8.31) provides that the rate of return used in determining a reference tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (as reflected in the terms and conditions on which the reference service is offered and any other risk associated with delivering the reference service).

By way of example, the Code notes that the rate of return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing Model (CAPM). The Code states that, in general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Authority is satisfied that to do so would be consistent with the pricing objectives contained in section 8.1 of the Code.

## 12.3 Determining the Rate of Return Framework

The Authority employs the Officer (1994) version 3 WACC formulation<sup>4</sup>. This approach defines firm cash flows in nominal, post-tax terms and modifies the cash flows, as opposed to the discount rate, for tax and the effects of dividend imputation. Allowing for the cash flow adjustments described, the WACC is:

$$WACC = \hat{k}_e(1 - L) + k_dL$$

where  $L$  is firm leverage (debt to total value),  $\hat{k}_e$  is the cost of equity and  $k_d$  is the cost of debt.

Other features of the Authority's recently revised approach are that:

- the value of gamma adopted is 0.5;
- the risk-free rate is based on a 20-day average of the 10 year government bond rate;
- the market risk premium adopted is 6.0 per cent;
- the debt beta is estimated as the mid-point between zero and the debt margin divided by the market risk premium; and
- the Conine beta levering formula, which incorporates the imputation-adjusted corporate tax rate, is adopted in place of the Brealey Myers formula.

### *Allgas' proposal*

Allgas applied a vanilla post-tax WACC to determine the return on capital. This is the same approach adopted by the Authority. In its initial revised access arrangement, Allgas proposed a post-tax nominal WACC of 8.75 per cent and applied this to the rolled forward asset valuation for the purposes of determining the return on capital over the access arrangement period. In its amended revised access arrangement, Allgas proposed a post-tax nominal WACC of 8.78 per cent, to account for changes in the risk-free rate.

<sup>4</sup> Officer (1994) presents four versions of the model that vary according to the definition of company post-tax net cash flows.

### *Submissions from stakeholders*

In response to the Authority's Draft Decision, the Energy Users Association of Australia (EUAA, 2006) argued that the nominal post-tax WACC seemed to be high in comparison with other WACC decisions. The EUAA were concerned that the Authority had acquiesced to the distributors' high WACC proposals and that adopting a lower WACC would reduce costs to consumers and provide an incentive for Queensland's gas distribution industry to become more efficient.

### *QCA position*

In its Draft Decision, the Authority accepted the post-tax nominal WACC of 8.75 per cent proposed by Allgas. To the extent that submissions received in response to the Draft Decision commented on matters relevant to the WACC proposed by Allgas and accepted by the Authority, they did not raise any issues that convince the Authority to amend its decision.

Consequently, the Authority does not propose to revisit the setting of the rate of return and confirms its Draft Decision to accept the WACC proposed by Allgas of 8.75 per cent.

In light of this decision, and in order to maintain internal consistency within this Final Decision, the Authority will also not revisit the estimated rate of inflation. To do otherwise would create internal inconsistencies between the risk-free rate and the rate of inflation. Furthermore, Allgas will be compensated for any divergence between forecast and actual inflation through the annual revision to reference tariffs.

The following discussion largely reflects that contained in the Draft Decision and is reproduced here for the sake of completeness in this Final Decision.

## **12.4 Quantifying the Risk-Free Rate**

The risk-free rate is an input to both the CAPM and the cost of debt. The market risk premium (MRP), adjusted by a firm's equity beta, is added to the risk-free rate to determine the cost of equity and the debt margin is added to the risk-free rate to determine the cost of debt.

In setting the risk-free rate, there are three important issues to consider: choice of the proxy instrument, measurement period and the term of the risk-free rate. To date, the Authority has benchmarked the risk-free rate with reference to Commonwealth Government bonds, averaged the rate over 20 days and determined the rate with reference to the yield on a 10 year maturity bond.

### *Allgas' proposal*

Allgas adopted the yield on a 10-year Commonwealth Treasury bond on the basis that:

- investment in infrastructure assets is of a long term nature, in which case a risk-free asset with similar duration should be used;
- to date, measurement of the market risk premium has largely been based on the 10-year nominal Commonwealth bond; and
- 10-year bonds are less volatile due to their longer term outlook.

In its initial revised access arrangement, Allgas proposed a risk-free rate of 5.18 per cent using the average yield over the 20 trading days commencing 8 August 2005.

Allgas revised its proposed risk-free rate in its submission to the Draft Decision and used the average yield over the 20 trading days up to and including 24 February 2006 to arrive at a risk-free rate of 5.28 per cent.

#### *Other jurisdictions*

IPART (2005) used the 20 day average of the yield on a 10-year Commonwealth Government bond to determine the appropriate risk-free rate.

The ESCV (2002) has derived its proxy real risk-free rate as the average of the redemption yield on inflation-indexed bonds over 20 trading days.

ICRC (2004) calculated the risk-free rate using Commonwealth Government bond data as published by the RBA. The Commission interpolated an implied 10-year maturity because no bond had a 10-year maturity at the time of the decision.

#### *Submissions from stakeholders*

The Authority received no submissions on this issue.

#### *QCA position*

The Authority accepts Allgas' approach to determining the appropriate value for the risk-free rate. The Authority is of the view that the rates that are determined by the market provide the best estimate of expected financial conditions over the term of the bond. This is because the market rates, by their very nature, incorporate the greatest amount of information and the views of market practitioners.

In its Draft Decision, the Authority calculated the risk-free rate using an average of the yield on a Commonwealth Government 10-year bond for the 20 days up to and including 29 September 2005. As such, the nominal risk-free rate that the Authority used for the purposes of determining its estimate of the appropriate rate of return in the Draft Decision was 5.25 per cent.

Regardless of the differences on this issue between the Authority and Allgas at the time of the Draft Decision, the Authority accepted the rate of return proposed by Allgas. Despite changes in the risk free rate, the Authority does not propose to change its decision, as it was not based on an acceptance of Allgas parameters. The Authority also notes that, if its WACC calculation was updated to account for changes in the risk-free rate since the Draft Decision, the corresponding real WACC would actually be lower than is currently the case.

## **12.5 Determining the Capital Structure**

A firm's WACC is the weighted average cost of servicing the various classes of financial claims on the firm. Each source of capital or financial claim involves different risks and, therefore, different costs. Business or operating risk reflects the risk of the firm when it is solely financed by equity funds. The addition of debt financing increases the risk to equity holders and hence the cost of equity.

The Authority's typical approach to determining the capital structure for a regulated business involves determining an 'optimal' capital structure by examining the average level of leverage in an industry (or set of related industries), regulatory precedents and by using simulation techniques.

### *Allgas' proposal*

Allgas noted that it is widely regarded among Australian regulators that the appropriate level of gearing to be assumed for an energy distribution business is 60 per cent and has adopted this benchmark in its rate of return calculations.

### *Other jurisdictions*

IPART (2005) set the capital structure for AGL at 60 per cent debt and 40 per cent equity.

The ESCV (2002) adopted an assumed gearing level of 60 per cent of debt to assets. This was based on observed gearing levels by comparable Australian businesses.

ICRC (2004) set a capital structure of 60 per cent debt and 40 per cent equity.

The ACCC (2003) set EAPL's capital structure at 60 per cent debt and 40 per cent equity.

### *Submissions from stakeholders*

The Authority received no submissions on this issue.

### *Consultant's assessment*

The Authority employed the Allen Consulting Group (ACG) to provide advice on several of the rate of return parameters, including the appropriate capital structure for the service providers.

ACG considered the gearing levels of various listed Australian gas network businesses and found an average gearing level in 2004/05 for the sample of companies to be around 50 per cent. However, this average increases to around 61 per cent when two of the companies with substantial interests outside of pipeline infrastructure are excluded from the sample. ACG also considered a sample of listed US gas companies and found an average gearing level of between 50 and 60 per cent.

ACG also noted that there is regulatory consensus over the regulated capital structures for gas companies and that regulators have tended to adopt a gearing ratio of 60 per cent. ACG could find no evidence to suggest that gas distribution in Queensland is sufficiently different from other jurisdictions to warrant a departure from regulatory practice. ACG recommended that a gearing level of 60 per cent be applied in calculating the WACC for the Queensland gas distribution businesses.

### *QCA position*

The Authority notes that the recommendation made by ACG is consistent with the proposal of both Allgas and Envestra and is also consistent with regulatory precedent in Australia. The Authority is satisfied that an assumed gearing level of 60 per cent meets the requirements of the Code.

The Authority accepts Allgas' assumed capital structure of 60 per cent debt and 40 per cent equity.

## 12.6 Determining the Cost of Debt

The cost of debt is typically expressed as the sum of the risk-free rate and a debt margin. The debt margin will vary depending on the entity's credit rating and the term of the debt.

In its 2001 Final Decision, the Authority used an approach which estimated debt costs by reference to the interest rate margin above the risk-free rate. At that time, the Authority set the debt margin at 155 basis points, reflecting the margin applying to debt rated at BBB+ at that time.

### *Allgas' proposal*

Allgas noted that recent regulatory precedent was to use a credit rating of BBB to BBB+ for a regulated energy distribution business with 60 per cent gearing. Allgas accepted the Authority's recommendation and set a debt margin of 130 basis points.

Allgas used a cost of debt of 6.7 per cent, based on a risk-free rate of 5.28 per cent, a debt margin of 130 basis points and debt financing costs of 12.5 basis points (see section 12.7).

### *Other jurisdictions*

IPART (2005) set a debt margin range of 113 -122 basis points (including 12.5 basis points for debt-financing costs) based on a 20-day average of CBASpectrum data for BBB+ and BBB rated bonds.

The ESCV (2002) set a debt margin of 110 basis points based on CBASpectrum data for BBB+ corporate bonds averaged over the same days as the risk-free rate was calculated.

ICRC (2004) adopted a range of 124.5 to 143 basis points for the debt margin (including debt-financing costs) based on a credit rating range of BBB+ to a and using CBASpectrum data.

The ACCC (2003) used a 40-day average of the BBB+ debt margin for five-year maturities using CBASpectrum data and adopted a debt margin of 92 basis points.

### *Submissions from stakeholders*

The Authority received no submissions on this issue.

### *Consultant's assessment*

#### *Credit Rating*

The Authority engaged ACG to advise on the appropriate cost of debt for the service providers. In assessing the cost of debt for the service providers, ACG first considered the appropriate credit rating to apply to the service providers, and then considered the appropriate debt margin given the assumed credit rating.

ACG noted that, provided that differences between actual company ratings and regulated company ratings are taken into account, analysis of actual credit ratings and financial ratios for Australian energy network companies provides a useful benchmark for assessing a credit rating for the regulated Queensland gas distribution businesses. ACG analysed the credit ratings and financial ratios of various Australian energy network companies for the purposes of comparison with the Queensland distribution businesses. It was apparent from this analysis that companies with higher gearing levels had lower credit ratings.

ACG analysed financial data for the service providers based on their regulatory accounting statements, which provide financial information for the regulated part of the business. ACG considered a base case scenario and also a scenario where income had decreased by 5 per cent but costs had remained steady. ACG noted that the pre-tax interest coverage ratio and the funds from operations (FFO) interest coverage ratio suggest an A rating in 2002-03 and a BBB rating in 2003-04. ACG also noted that the FFO to total debt ratios suggested a rating of AA or A in 2002-03 and A in 2003-04. ACG suggested that the coverage ratios lie mainly near the threshold between BBB and A ratings and that a rating of BBB+ or A- would be expected. ACG recommended that the Authority err on the side of conservatism and adopt a BBB+ credit rating for the regulated entities based on an assumed gearing level of 60 per cent.

#### Debt Margin

ACG assessed various sources of data in considering an appropriate debt margin to apply to a 10-year corporate bond with a rating of BBB+. ACG acknowledge that there is a growing body of evidence to suggest that the CBASpectrum estimates do not reflect debt margins for longer term debt. However, as a starting point, ACG noted that the CBASpectrum spread on 10-year corporate BBB+ rated bonds averaged over the 20 days to 30 September 2005 was 101.6 basis points.

ACG considered the Bloomberg spreads for various maturities and credit rating, although Bloomberg does not provide data for BBB+ rated bonds of 10-year maturity. However, ACG note that for BBB+ rated bonds with maturities of 9 years, the Bloomberg estimate was 22.1 basis points higher than the CBASpectrum estimate. Similarly, the difference was 20.9 basis points for estimates of 10-year A rated bonds.

ACG also considered actual corporate bonds, with maturities of 4 years or more, that were currently trading in the market. The spread of these bonds was compared to the spreads as suggested by the Bloomberg and CBASpectrum data. ACG found that the Bloomberg estimates are significantly more accurate predictors of actual bond margins, particularly for longer-term debt. This evidence suggested that the CBASpectrum estimates were underestimating the correct spread by around 20 basis points.

The Bloomberg data does include a spread for a BBB+ rated bond with a maturity of 9 years. ACG took a simple linear extrapolation from the predicted margins for 8 and 9 year bonds and found an implied margin of 133.6 basis points for 10-year bonds. This was 30 basis points above the CBASpectrum estimate. However, ACG noted that this is likely to be an overestimate as the yield curve tends to be concave.

ACG also found that evidence from credit-wrapped bonds in Australia suggests that the debt margin for a BBB+ rated infrastructure business in Australia may be in the range of 95 – 100 basis points. While the CBASpectrum value is within this range, ACG noted that this data should be treated with caution.

ACG noted that there was a BBB+ rated 10-year bond issued by Santos and that these bonds began trading on 27 September 2005. As such, there were only four observations for this bond to 20 September 2005. The bond was trading at a debt margin of 122 basis points, on average, over the four days.

It is clear that the different sources of evidence provide different estimates as to the debt margin for a 10-year BBB+ rated corporate bond. ACG has considered all the sources of evidence and suggested that a debt margin of 130 basis points would be a reasonable and conservative estimate. This is 28 basis points higher than the debt margin obtained using CBASpectrum data.

*QCA position*

The Authority accepts the view of the National Economic Research Associates (NERA) and ACG that the estimates of long-term bond yields using the CBASpectrum data are likely to underestimate the actual debt margins for Australian firms. The Authority also notes that Bloomberg do not provide estimates for 10-year BBB+ rated bonds, although it appears that Bloomberg consistently provides more accurate forecasts of actual debt margins than does CBASpectrum.

It appears reasonable to place the heaviest weight on the estimates that are provided by Bloomberg, given that the Bloomberg estimates tend to be fairly accurate predictors of actual debt margins observed in the market across a range of credit ratings and maturities. It is also reasonable to consider the CBASpectrum estimates with a further addition to the estimated spread of around 20-25 basis points to account for downward bias in the CBASpectrum estimates. The evidence surrounding credit-wrapped bonds and the Santos bond certainly seem to be somewhat thinner.

A simple linear extrapolation of the Bloomberg data would, in usual circumstances, tend to overestimate the debt margin as yield curves do tend to be somewhat concave in shape. This would suggest that a debt premium of 133 basis points is too high. This is backed up by other available data, notably the CBASpectrum data which suggests a debt margin of just under 102 basis points, which adjusts to around 122 to 127 basis points after accounting for the downward bias.

Based on the weight of evidence, the Authority has accepted that ACG's recommendation of 130 basis points for the debt margin is a reasonable and conservative estimate of the actual debt margin for a 10-year corporate bond from a firm with a BBB+ credit rating.

**12.7 Debt Raising Costs**

When raising debt the service provider has to pay debt financing costs over and above the debt margin.

*Allgas' proposal*

Allgas has adopted a debt issuance rate of 12.5 basis points, on the basis that this was consistent with the Authority's recent decision on electricity distribution.

*Other jurisdictions*

IPART (2005) accepted AGL's proposal to include 12.5 basis points to account for debt-raising costs.

ICRC (2004) allowed 12.5 basis points to be included in the debt-margin to account for debt-financing costs.

*Submissions from stakeholders*

The Authority received no submissions on this issue.

*Consultant's assessment*

ACG recognised that there is also a transaction cost in raising finance initially. ACG have indicated that recent research suggests that the 12.5 basis points usually used by Australian regulators may be considered to be an upper bound for that costs based on a recent detailed study that was conducted by ACG. Nonetheless, ACG recommended that an allowance of 12.5 basis points for debt-raising costs be included.

*QCA position*

Under the industry benchmark approach adopted by the Authority for determining the cost of debt, the Authority accepts that efficient debt-raising costs should also be recognised. As these costs are related directly to debt raising, the Authority is inclined to add a margin to the cost of debt, rather than separately identifying the costs in operating expenditure.

The Authority accepts that currently 12.5 basis points is generally accepted as an efficient level of cost to allow for debt issuing and will add this amount to the service providers' debt margin. The Authority also notes that this figure is based on the best empirical evidence that is currently available.

On this basis, the Authority has determined that the debt margin for should be 142.5 basis points, representing a debt margin of 130 basis points plus an additional 12.5 basis points in recognition of debt-raising costs.

**12.8 Quantifying the Market Risk Premium**

The market risk premium (MRP) is the return investors require, in addition to the risk-free rate, for investing in a well diversified portfolio of risky assets. As the MRP is an expected return, it is not directly observable. Historical estimates such as the historical difference between realised returns of the stock market and the risk-free rate are commonly used to provide an indicator of the forward-looking MRP. However, this approach is sensitive to the averaging period.

In its 2001 review of access arrangements, the Authority considered a market risk premium of 6 per cent was an appropriate estimate. The Authority has adopted a MRP is 6 per cent in all of its other regulatory decisions.

*Allgas' proposal*

Allgas argued that historical data up to 2004 indicates that the market risk premium was consistently in excess of 6.0 per cent. However, Allgas recognised that there is some debate over the length of the period that should be used to provide the best estimate of the market risk premium.

Allgas has adopted a market risk premium of 6.0 per cent, noting that this was consistent with regulatory precedent.

*Other jurisdictions*

IPART (2005) adopted a uniformly distributed market risk premium range of 5.5 to 6.5 per cent.

The ESCV (2002) adopted a market risk premium of 6 per cent.

ICRC (2004) used a market risk premium of 6 per cent which it believed was supported by the available empirical evidence.

The ACCC (2003) considered that EAPL's proposed market risk premium of 6 per cent was not inconsistent with the requirements of the Code.

#### *Submissions from stakeholders*

The Authority received no submissions on this issue.

#### *Consultant's assessment*

Lally undertook surveys of the major methodologies used in estimating the market risk premium as part of previous reviews undertaken by the Authority. These methodologies include historical averaging, historical estimation and forward-looking estimation based on forecasts. Lally noted that these methodologies produce a range of estimates for the market risk premium and that, as a consequence, there is considerable statistical uncertainty surrounding the estimate of this parameter. Lally suggested that all of the approaches suffer from methodological or estimation difficulties and that it is appropriate to consider estimates derived from multiple sources. Lally concluded that the Authority's current estimate of 6 per cent was reasonable in the context of the Officer CAPM.

ACG also considered evidence from historical estimates, forward-looking estimates and market practitioners of the appropriate MRP. ACG noted that historical estimates of the MRP in Australia were in the order of 4.5 – 7.5 per cent but that there were some concerns over whether such estimates were a reliable guide to the MRP over a future period. ACG argued that historical measures do not take account of ex-ante expectations and that methods that adjust historical estimates to account for unexpected capital gain suggest an ex-ante MRP using historical data may be between 4.5 to 6 per cent. ACG also noted that it would appear that market practitioners typically view the MRP as being 6 per cent but that the expected MRP over the future period may be below this level.

#### *QCA position*

The Authority accepts that there may be some estimates of historical MRPs that suggest a value of greater than 6 per cent. However, the weight of evidence clearly suggests that the MRP is no greater than 6 per cent and may in fact be lower than this.

The Authority also notes that regulators in Australia have almost always adopted a MRP of 6 per cent for regulatory purposes. Regulatory consistency would suggest that it is appropriate to use a MRP of 6 per cent for the Queensland gas distributors.

The Authority sees no reason to change its view as to the appropriate MRP. Indeed, the Authority is of the view that a MRP of 6 per cent is likely to be a conservative estimate of the true forward-looking MRP.

For example, a recent New Zealand Treasury study of the market risk premium for the purpose of determining the required capital contribution to the New Zealand Superannuation Fund concluded that the long-term forward looking market risk premium sat in the range of 3 per cent to 5 per cent and recommended 4 per cent as the appropriate level.

## **12.9 Determining the Equity Beta**

An equity beta is required to determine the distributors' cost of equity for use in the CAPM formula. Because the observed equity betas of chosen comparators are generally based on different levels of gearing, there is a need to standardise the observations to eliminate this impact. This is done by first converting the observed equity betas to their underlying asset

betas. On the basis of the resulting asset betas, an asset beta for the distributors can be determined. That asset beta is then converted to an equity beta using the level of gearing assessed as appropriate for the distributors. The conversion from equity betas to asset betas and back to an equity beta is done via an appropriate levering/de-levering formula.

#### Levering Formula

Following its recent technical review, the Authority has adopted the Conine formula as the appropriate formula to use in regulatory determinations, with the corporate tax rate replaced by the imputation-adjusted tax rate, consistent with the corporate tax environment in Australia. The Authority notes that this formula is sufficiently general to accommodate any assumptions that the Authority makes on the value of gamma and/or the debt beta.

$$\beta_e = \beta_a \left[ 1 + (1 - T_e) \frac{L}{1 - L} \right] - \beta_d (1 - T_e) \frac{L}{1 - L}$$

where:

$\beta_e$  is the equity beta;

$\beta_a$  is the asset beta;

$\beta_d$  is the debt beta;

$L$  is leverage (debt to total assets); and

$T_e$  is the imputation adjusted tax rate

#### *Allgas' proposal*

Allgas noted that, in its recent determination, the Authority had increased the equity beta for electricity distribution from 0.71 in its 2001 Determination to 0.9, a 27 per cent increase. This increase, if applied to the gas equity beta from the 2001 access arrangement of 0.97, would lead to an equity beta in the vicinity of 1.20.

Allgas argued that a higher beta for gas distribution, relative to electricity distribution, is further supported by the additional risks faced by a gas distribution business over an electricity distribution business. These risks include:

- higher volatility in demand;
- competition from substitute products such as electricity and LPG;
- high unit costs for gas distribution;
- benefits provided by the Queensland Government to substitute products (for example, subsidies for solar hot water and electric heat pumps); and
- little or no market development from the retail sector.

Allgas has adopted an equity beta of 1.10 based on recent regulatory decisions and its view that a gas distribution business has a higher systematic risk than electricity distribution.

*Other jurisdictions*

IPART (2005) was satisfied that an equity beta uniformly distributed around 0.9 met the requirements of the Code. IPART noted that the equity beta should be a forward looking estimate and that there was evidence to suggest that AGL's equity beta had declined in recent years.

The ESCV (2002) adopted an equity beta of 1. The Commission noted that a far lower equity beta (0.55) would be derived if exclusive reliance were placed on the most recent market evidence. However, the Commission sought to provide continuity between regulatory decisions and also had regard to the long-term consequences of the Commission's decisions for the Victorian gas industry.

ICRC (2004) considered that the supportable equity beta was in the range of 0.9 to 1.09. This view was based on available empirical evidence and regulatory precedent.

The ACCC (2003) noted that current empirical estimates of the re-levered equity beta suggest that the equity beta should be considerably less than 1. However, the Commission was of the view that it may be premature to rely wholly on those estimates given the thin trading and limited number of observations. The Commission considered that an equity beta of 1 was appropriate at the time.

*Submissions from stakeholders*

The Authority received no submissions on this issue.

*Consultant's assessment*

The Authority engaged ACG to consider the appropriate equity beta to use for a regulated gas distribution business in Queensland. ACG calculated estimates of proxy betas using the Conine de-levering formula and using a debt beta assumption of 0.1. This approach ensures consistency with the method that is used by the Authority.

ACG considered from first principles the factors that might affect a company's asset beta. ACG considered the nature of the product and the likely income elasticity of demand, noting that if income elasticity is high then a higher asset beta would be expected. ACG suggested that gas distribution services are linked to GDP growth and that this is heightened in Queensland where the economy is growing faster than the Australian economy. ACG also held that commercial and industrial load tends to be more sensitive to changes in GDP than residential load, as residential load tends to represent basic household consumption. Commercial and industrial load, as a proportion of overall load, is higher in Queensland than in other states and this suggests that gas consumption in Queensland will be sensitive to GDP.

While pricing structures that have a significant fixed component would cushion the revenue impact from an economic downturn, ACG did not expect the pricing structure of the service providers to have a mitigating effect on the asset beta.

ACG also noted that, while contractual periods for gas transmission tend to be long term with significant take-or-pay components, the contracts entered into by gas distributors tend to involve smaller end users, shorter time horizons and have greater volume flexibility. However, ACG did not believe the resulting impact on the asset betas of distributors, as compared to gas transmission companies, was clear.

ACG agreed that a price-cap form of regulation that is applied to gas distribution businesses in Queensland makes that activity subject to a slightly higher element of systematic risk than is

applicable for electricity distribution businesses which are regulated under a revenue cap. ACG did note that it is possible for gas service providers to seek changes to reference tariffs in the event of significant changes in costs.

Overall, ACG believed that the indicators of systematic risk discussed above suggest that the asset beta of the Queensland gas distribution businesses would be similar to that of similar businesses in other states, although Queensland may be slightly higher due to its large industrial component. Gas distribution is also likely to have slightly higher risk than electricity distribution in Queensland due to the form of regulation and composition of demand.

ACG then constructed a proxy group of listed Australian gas companies and US gas companies for the purpose of deriving an appropriate beta estimate. In doing so, ACG took into account the potential impact of the 'dot-com bubble' period (March 2000 to mid-2001) on estimates of these comparators' equity betas. This is because the rise (and subsequent fall) in technology stocks led to a decrease (and subsequent increase) in the values of safe assets (for example, utilities) as investors switched between stocks. This has meant that utility stocks have been moving contrary to the general movements of the market, which has the effect of biasing their beta estimates downward. If it is assumed that the dot-com bubble was an abnormal event, then beta estimates for utility stocks obtained using data from the bubble period will be biased downward.

Although the effect of the dot-com bubble was most pronounced in the US, there is evidence to suggest that in Australia the utilities sector did move contrary to the market as a whole, particularly for the period from March 2000 to the middle of 2001. Therefore, any current beta estimates for the last five years will include observations from the dot-com bubble period. In particular, the current 60-month beta estimate includes the period after November 2000 and so includes much of the dot-com bubble. As such, these estimates of beta may not provide an unbiased estimate of future betas.

When analysing Australian and US comparator firms ACG has used three approaches to try and remove the bias in the forward-looking beta estimates. Firstly, ACG has presented beta estimates using shorter periods (than the standard 60 month period) of 48 months and 60 weeks, as these will contain less data from the dot com period. Secondly, 60 month estimates have been presented for entities over the period prior to the dot com bubble. And thirdly, for the US gas companies, 60 month estimates have been provided using data that excludes observations affected by the dot com bubble.

ACG estimated rolling equity beta estimates using both weekly and monthly data for a group of proxy Australian companies (re-levered to 60 per cent gearing). The weekly estimates were between 0.6 and 1.4 from 1996 to 1998 and then started to fall quickly from late 1998. Weekly estimates rose again after 2001, particularly when the dot com bubble estimates dropped out of the sample set. Since January 2004 the weekly estimates have been in the range from 0.4 to 0.8 with an average equity beta value of 0.55. The most recent 60 month estimate puts beta at 0.21, but ACG note that this may significantly underestimate the true forward-looking beta as not all the observations of the dot com period have dropped out and the monthly series will tend to follow the weekly estimates, which have clearly increased since the dot com bubble.

ACG carried out a similar exercise for US listed gas transmission and distribution companies and found a similar phenomenon. That is, betas tended to drop during the dot com period and have started to rise as dot com observations drop out of the sample set. ACG also calculated betas using 60 monthly estimates but excluding data from the dot com period. The geared equity beta falls between 0.3 and 0.8 until 1998 and has been more stable at around 0.5 to 0.6 since July 2002.

ACG believe that the Australian and US evidence supports the supposition that the geared equity beta of the Queensland gas distributors is likely to be above 0.6, and is probably above 0.9.

Based on ACG's assessment of the evidence, and noting that direct evidence on Australian equity betas for similar companies is deficient, it has concluded that an equity beta of 1.0 for the Queensland gas distribution businesses is justified.

#### *QCA position*

Because it is not possible to directly observe the equity beta's of the regulated entities, the first-principles analysis conducted by ACG examines the explanatory factors that underpin the systematic risk of the service providers.

The Authority acknowledges commercial and industrial businesses consume a significant proportion of the gas that is distributed by the service providers and that commercial and industrial consumption will be more closely related to economic conditions than will residential consumption. As such, the service providers will be subject to some level of systematic risk.

The Authority also acknowledges that the equity beta that was considered appropriate for electricity distribution was influenced, by the fact that there were provisions for cost pass-throughs and review triggers in the event that demand was significantly different to forecast. These factors led to the electricity distributors receiving a lower equity beta than may have otherwise been the case. In this regard, the Authority notes that the equity beta adopted for most electricity businesses in Australia is 1.0, compared with the 0.90 adopted in the Authority's Final Determination for Queensland electricity distributors.

The Authority is of the view that, in many instances, gas is a fuel of choice, while everyone generally connects to electricity. Because it is a fuel of choice, it faces competition from other sources of energy such as electricity and LPG. As such, the Authority accepts that the gas distributors will be subject to a greater level of systematic risk than the electricity distributors and that a higher equity beta is justified.

The Authority notes that recent regulatory decisions in other jurisdictions in Australia have tended to adopt an equity beta in the region of 1.0. However, it is clear that Queensland service providers have a much higher proportion of commercial and industrial consumption to total consumption, than do their counterparts in other states. Industrial and commercial consumption is likely to be closely linked to prevailing economic conditions, whereas residential consumption is likely to be less affected by changes to economic conditions. As such, the Authority is of the view that the systematic risk of the Queensland service providers is likely to be higher than the systematic risk of the service providers in other states.

With regard to the empirical estimates of the equity beta the Authority accepts that the dot-com bubble is likely to have affected the measurement of betas over recent years, and that measures of beta using data from this period may underestimate the true value of beta. However, it is not clear to what extent the equity betas will increase in the post dot-com period. The Authority accepts that betas calculated using recent weekly data may provide better estimates as the data from the dot-com period has now dropped out of this sample. However, the weekly estimates of the Australian and US comparators provide significantly different estimates of equity betas for gas companies. Nonetheless, the Authority accepts that current low levels for monthly estimates of equity betas for gas companies in both Australia and the US are not likely to persist and that there is likely to be some upward trend as we move away from the dot-com period.

The Authority has considered all the evidence with regards to the appropriate equity beta for gas service providers in Queensland and is of the view that empirical estimates are not currently

sufficiently accurate to be heavily relied upon. The Authority is of the view that gas service providers are subject to higher systematic risk than the electricity distributors, largely because of the nature of the product, and that Queensland gas service providers will be subject to higher systematic risk than gas service providers in other states. On this basis, the Authority believes that an equity beta of 1.1 is the best estimate of the appropriate equity beta for a gas service provider in Queensland.

### 12.10 Determining the Dividend Imputation Rate

Gamma is the product of two elements, the utilisation rate of imputation credits and the ratio of imputation credits to company tax paid. The theoretical value of gamma ranges between zero and one (inclusive) and can be recognised in the cost of capital model through either an adjustment to the regulated firm's cash flows or to the discount rate. The closer gamma is to one, the lower the regulated price.

In its 2001 review of access arrangements, the Authority employed a 0.50 value (50 cents in the dollar) for gamma. To date, the Authority has used this value for gamma in all of its regulatory decisions.

#### *Allgas' proposal*

Allgas argued that, in estimating gamma, consideration should be given to estimates derived from market data. In its initial revised access arrangement, Allgas adopted a gamma of 0.35 based on work published by Hathaway and Officer (2004). Allgas argued that this was consistent with the Authority's regulatory precedent and Hathaway and Officer's aggregate tax statistic methodology.

In its amended revised access arrangement, Allgas has accepted the Authority's Amendment 12.1 and set the value of gamma at 0.5.

#### *Other jurisdictions*

IPART (2005) set a uniformly distributed range for gamma of 0.3 to 0.5. This was based on several academic studies and recent independent expert reports on ASX-listed companies prepared by market practitioners.

The ESCV (2002) was of the view that the market value of franking credits at the point of creation was approximately 50 per cent of their face value (a gamma of 0.5).

ICRC (2004) considered that background material and analysis supported a gamma range of 0.3 to 0.5.

The ACCC (2003) noted that there were good arguments for gamma being set at a value of 1. However, the ACCC set gamma at 0.5 noting that this value was at the extreme lower end of the range that has the quality required by the Code.

#### *QCA position*

To date, the Authority has employed a gamma of 0.50 in all its regulatory decisions. The Authority models the impact of gamma in the firm's cash flows.

Lally has undertaken work for the Authority as part of this, and previous, reviews and, in the Authority's view, has made a strong case that the value of the utilisation rate in the context of the Officer CAPM should be 1.0 (or very close to 1.0), for consistency with the domestic

framework of the model. A utilisation rate of close to 1.0 would result in a gamma considerably in excess of the 0.50 currently adopted by the Authority.

On the basis of all the evidence, the Authority considers that a value of gamma greater than 0.5 is justified. However, in the interest of regulatory certainty, the Authority has decided to continue to use a gamma value of 0.5. The Authority notes that Allgas has accepted the required amendment and has set the value of gamma at 0.5 in its updated revised access arrangement.

### 12.11 Expected Inflation

Expected inflation is not an explicit parameter in the calculation of WACC. Rather, it is a component of the risk-free rate.

In its 2001 review of access arrangements, the Authority estimated the expected inflation rate as the difference between the nominal and indexed long-term Commonwealth Government bond yields.

#### *Allgas' proposal*

Allgas has adopted an inflation rate based on the difference between a 10-year Commonwealth bond rate and a similar indexed bond rate averaged over 20 days. In its initial revised access arrangement, Allgas adopted an inflation rate of 2.71 per cent.

In its amended revised access arrangement, Allgas accepted the Authority's Amendment 12.2 and adjusted the forecast rate of inflation to 2.77 per cent.

#### *Other jurisdictions*

ESCV (2002) derived its proxy real rate and the inflation rate using an average of the redemption yield on inflation-indexed bonds over 20 days.

ICRC (2004) calculated the inflation rate using the Fisher equation and the nominal risk-free rate and the real risk-free rate.

IPART (2005) calculated the inflation rate based on the difference between nominal and real interest rates using the Fisher equation.

#### *Submissions from stakeholders*

The Authority received no submissions on this issue.

#### *QCA position*

The benefit of the Authority's current approach is that it delivers a forward-looking estimate of inflation rather than a historic measure. This method is also consistent with the approach adopted by other regulators.

The Authority calculated an expected inflation rate based on the difference between the 10 year Commonwealth bond rate and a similar duration indexed bond rate, averaged over 20 trading days up to and including 29 September 2005. The 20 trading day average yield on a Commonwealth Indexed Bond was 2.42 per cent, while on the Commonwealth bond the rate was 5.25 per cent. This implies an expected inflation rate of 2.77 per cent.

The Authority notes that Allgas has amended its forecast rate of inflation to 2.77 per cent, in line with the amendment required by the Authority.

As the Authority has not updated the WACC, the forecast inflation rate will not be updated and will remain at 2.77 per cent. This maintains the consistency between the calculation of the WACC and the calculation of nominal values of the building blocks.

## 12.12 Conclusion

The Authority undertook analysis of each of the WACC parameters with a view to calculating an appropriate WACC for the Queensland gas service providers. In many instances, the Authority rejected the arguments that have been put forward by the service providers and their respective parameter estimates. Based on the value of the parameters as selected by the Authority, a post-tax nominal WACC of 8.75 per cent was reached. Despite the fact that the Authority did not agree with the service providers as to the appropriate values for all of the WACC parameters, this WACC value was very close to the WACC value proposed by the service provider.

The Authority therefore decided in its Draft Decision to accept Allgas' proposal and set the WACC at 8.75 per cent. Despite marginal changes in the risk free rate, the Authority does not propose to change its decision, as it was not based on an acceptance of individual Allgas parameters. The Authority also notes that, if its WACC calculation was updated to account for changes in the risk-free rate since the Draft Decision, the corresponding real WACC would actually be lower than is currently the case.

### **Amendment 12.1**

**Allgas is required to amend its WACC value to 8.75 per cent.**

### 13. NON-CAPITAL COSTS

*The Authority engaged Energy Consulting Group (ECG) to assess the efficiency of the non-capital costs proposed by Allgas. In its report prior to the Draft Decision, ECG's analysis of past non-capital costs was hampered by "anomalies" in Allgas' cost allocations in 2003 and 2004. However, Allgas has subsequently provided ECG with sufficient information for it to analyse Allgas' past non-capital costs. ECG has established 2005-06 non-capital expenditure as being the most appropriate starting point for analysing expenditure over the next regulatory period.*

*In many instances, the Authority has accepted Allgas' forecasts based on ECG's recommendation. In other instances, the Authority has accepted ECG's recommendations that some of the forecast expenditure proposed by Allgas should be decreased as the expenditure does not comply with the Code.*

*One exception to accepting ECG's recommendations relates to Allgas' proposed marketing expenditure. The Authority included the amounts proposed by Allgas, given Allgas' past efforts and expenditure in this area, combined with the apparent growth that has been achieved, and that it represents only a modest increase in marketing costs from the current regulatory period.*

*The revised forecasts of Allgas' non-capital costs incorporate ongoing cost reductions in operating and maintenance and administration costs (excluding unaccounted for gas and corrective maintenance) of around 1.85 per cent each year.*

*The Authority has accepted Allgas' forecast costs for ancillary services.*

*The Authority has determined a revised forecast for unaccounted for gas (UAG) to reflect the slower rate of network renewal than that proposed by Allgas that has been adopted by the Authority. The Authority has used the price of gas proposed by Allgas to calculate the cost of UAG, as it provided further evidence to support this price following the Authority's Draft Decision.*

*The Authority has accepted Allgas' general approach to calculating regulatory tax. However, the Authority has used the parameters from this Final Decision to determine the appropriate allowance for tax.*

#### 13.1 Introduction

Non-capital costs are those costs associated with the operation and maintenance of the gas distribution network. These costs can be divided into the activities of:

- operating and maintenance – the bulk of non-capital costs, including costs directly attributable to the repair and upkeep of the network;
- administration and overheads;
- network development (marketing);
- ancillary services;
- unaccounted for gas (UAG); and
- tax.

## 13.2 Code Requirements

Under the Code (sections 8.36 and 8.37), non-capital costs are described as the operating, maintenance and other costs incurred in the delivery of the reference service. Non-capital costs may include, but are not limited to, costs incurred for generic market development activities aimed at increasing long-term demand for the delivery of the reference service.

A reference service may provide recovery of all non-capital costs (or forecast non-capital costs, as relevant) except for any costs that would not be incurred by a prudent service provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the reference services..

Section 8.2 (e) of the Code requires that any forecasts used in setting reference tariffs must be best estimates arrived at on a reasonable basis.

## 13.3 Determining Non-Capital Costs

In considering whether the forecast non-capital expenditure proposed by Allgas was in accordance with the Code, the Authority focused on the efficient costs that Allgas would be expected to incur in the operation of its network. It should be noted that the efficient level of expenditure does not necessarily correspond to actual expenditure.

The efficient level of non-capital expenditure will depend on the level of capital expenditure. A firm may decide that efficiency can be enhanced by fully maintaining capital currently in use. Alternatively, it may decide that it is more economic to spend less on maintenance with a view to earlier replacement of the network. Any trade-off that may occur between the two should not compromise the safety and integrity of the network as a whole, and should result in the overall lowest cost outcome for consumers consistent with the efficient operation of the network. The efficient level of non-capital expenditure will also be influenced by any augmentation or extension of the network.

Costs relating to unaccounted for gas and tax are considered separately in section 13.4 and 13.5.

### *Allgas' proposal*

Allgas provided updated forecasts of its non-capital costs consistent with its amended revised access arrangement (section 6 of its amended access arrangement information). According to Allgas, these costs include significant operating efficiencies which it expects to realise over the forecast period. Allgas' non-capital costs are summarised in Table 13.1.

**Table 13.1: Allgas’ forecast non-capital costs, 2006-07 to 2010-11 (\$m, nominal)**

<i>Type of Cost</i>	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Inspection	1.3	1.4	1.4	1.5	1.6
Planned maintenance	3.3	3.4	3.4	3.1	3.1
Corrective maintenance	2.7	2.6	2.5	2.2	2.0
Customer service	1.0	1.0	1.1	1.2	1.3
Maintenance planning & support	2.5	2.3	2.4	2.4	2.4
<b>Total operating and maintenance</b>	<b>10.8</b>	<b>10.7</b>	<b>10.8</b>	<b>10.4</b>	<b>10.4</b>
Network development	0.6	0.6	0.6	0.6	0.6
Ancillary services	0.6	0.6	0.7	0.8	0.8
<b>Total Non-Capital Costs</b>	<b>12.0</b>	<b>12.0</b>	<b>12.0</b>	<b>11.8</b>	<b>11.8</b>

*Note: The operating and maintenance costs in this table do not include forecast costs of UAG and tax, which are discussed separately in sections 13.4 and 13.5. Total non-capital costs may not add due to rounding.*

Energex Limited is engaged by Allgas as an independent contractor to operate and manage its natural gas network and provide most support services. Unlike OEAM and Envestra, Energex charges Allgas for the services it delivers to the regulated business of Allgas on an ‘at cost’ basis.

In its initial revised access arrangement information, Allgas provided only limited information on its performance over the current access period in relation to non-capital costs. However, Allgas indicated that forecast non-capital costs included in the current access arrangement were \$3.0 million higher than the actual costs incurred by Allgas over the current regulatory period. Allgas attributed this apparent saving to a cost allocation anomaly in 2002-03 and 2003-04 rather than any actual efficiency gain<sup>5</sup>.

#### *Other jurisdictions*

In its Final Decision, ESCV (2002) noted that, in considering the efficiency of non-capital costs, it was inevitable that the use of external benchmarks was required to establish changes in expenditure over time but that actual firm specific information was required to establish base-level expenditure. ESCV also suggested the information asymmetry between the service provider and the regulator (and its consultants) warranted it considering both the service provider’s historical trend in costs as well as external benchmarks.

ESCV concluded that, given the natural incentive of service providers to present information that supports estimates favourable to their interests, it was incumbent of the regulator to utilise an incentive form of regulation, such as CPI-X, to reveal efficient costs. While more than one service provider suggested the required efficiency gains were unnecessary as efficient cost estimates were already incorporated into their forecasts, ESCV required the service providers to achieve efficiency gains of 1 per cent for overall non-capital costs over the forecast period.

Other jurisdictional regulators have typically required service providers to incorporate non-capital cost efficiency improvements over the regulatory period. For example IPART (2005a) required CEG to adopt a 1 per cent productivity improvement over its five year access arrangement. Similarly, IPART (2005) expected AGLGN to make annual efficiency savings of 1.5 per cent each year in the areas of operating and maintenance expenditure, and administration and overheads.

<sup>5</sup> p.5, Allgas’ Access Arrangement Information (February 2006).

### *Submissions from stakeholders*

The EUAA (2006) was concerned that Allgas did not provide adequate information to allow the Authority to make informed decisions.

### *QCA position*

The Authority engaged Energy Consulting Group (ECG) to provide independent advice on Allgas' forecast non-capital costs included in its initial revised access arrangement. Following receipt of Allgas' amended revised access arrangement in February 2006, the Authority engaged ECG to assess Allgas' revised forecasts.

In its report prior to the Draft Decision, ECG was unable to use Allgas' historical cost data because past non-capital cost information could not be disaggregated into the same categories as those used by Allgas for its forecasts over the next regulatory period. In addition, substantial errors existed in the data that was available. In its Draft Decision, the Authority required Allgas to revise and sufficiently disaggregate the information needed to enable an appropriate assessment of forecast cost to be made.

In response to the Authority's Draft Decision, Allgas revised the information it had previously provided, including a breakdown of past expenditure into the same categories as forecast expenditure. Allgas noted that ECG, in its initial report, had not included cost pass-through expenditure for 2005-06 that had been approved by the Authority.

ECG subsequently accepted that the pass-through costs result in a permanent uplift in cost which should be considered in comparing 2005-06 forecast costs. As a result, ECG was able to establish efficient costs for Allgas in 2005-06 and used this as a starting point for analysing expenditure in the next regulatory period.

The Authority is satisfied that this approach to forecasting non-capital costs meets the requirements of the Code.

### *Operating and maintenance and administration costs*

ECG examined the forecast costs of inspection, planned maintenance, corrective maintenance, customer service and maintenance planning and support proposed by Allgas. For the Authority's Draft Decision, ECG provided revised forecasts for these non-capital expenditure items, mostly due to concerns about the large step change in costs compared to the Authority's forecast non-capital costs determined in 2001. As noted above, this concern has now been resolved with Allgas' provision of more comprehensive information on its expected 2005-06 non-capital costs.

In its initial revised access arrangement, Allgas forecast a doubling of its planned maintenance and corrective maintenance of cased crossings from 150 jobs in 2005-06 (prior to this Allgas only responded to leak reports) to 300 jobs in 2006-07. This level of activity was expected to continue until 2008-09 after which it would decrease back to 150 jobs each year and cease entirely after 2009-10.

In response to the Authority's Draft Decision, Allgas advised that it had revised downward its forecast for planned maintenance and corrective maintenance of cased crossings from 1,200 jobs identified previously to 360 jobs over the next access arrangement period. ECG acknowledged that the cased crossings program was not included in the forecast of costs for the current regulatory period and therefore represented additional expenditure to be included in the forecasts for the next regulatory period.

The number of cased crossing inspections also increased from the 30 inspections estimated in Allgas' initial revised access arrangement to 360 inspections estimated in its amended revised access arrangement. ECG accepted that this was also a new activity that was not included in forecasts for the current regulatory period. ECG considered that it was reasonable for all cased crossings to be inspected as part of the revised risk mitigation program over the next regulatory period.

Allgas also advised that an estimated 20 per cent of inspections would result in additional costs stemming from the need for corrective maintenance. ECG considered this represented a reasonable estimate. However, ECG considered that, once a cased crossing had been inspected, Allgas would perform either corrective maintenance if there was a fault or otherwise it would perform planned maintenance, but not both. As a result, ECG reduced the 360 planned maintenance jobs that Allgas forecast by the 20 per cent estimate of jobs that would be resolved through corrective maintenance. ECG accepted Allgas' unit rates for undertaking this work as efficient.

In its initial report, ECG considered that the trend in costs for inspections and planned maintenance was appropriate. As noted above, ECG accepted the revised inspection expenditure provided by Allgas in February 2006. Effectively, ECG retained its view of trends in inspection and planned maintenance expenditure but adjusted the numbers of activities in the first year of the forecast period and made a slight adjustment to account for work that would be included in the forecast cost of corrective maintenance. The Authority considers that ECG's forecast cost for inspection and planned maintenance is in accordance with the Code.

At the time of the Authority's Draft Decision, ECG's forecast cost for corrective maintenance reflected a lower level of expected leaks than proposed by Allgas for 2006-07. ECG considered the increase from an estimated 1,500 repairs in 2005-06 to a forecast of 2,000 repairs in 2006-07 was not adequately explained by Allgas and recommended the Authority accept only costs based on the lower historic number. ECG suggested that, while improved odorisation of gas in the Allgas network had caused leakage reports to increase, this should have returned to more normal levels before the next access arrangement period commenced.

In response to the Authority's Draft Decision, Allgas provided information to explain the increase in leak repairs for 2006-07 and the declining trend thereafter. Allgas indicated that it had experienced a 168 per cent increase in reported leaks at one of its gate stations after it increased the level of odorisation to comply with statutory requirements. Allgas expected a similar effect for the remainder of its network as upgrades occur, and that this would result in an increase in repairs for 2006-07. Allgas took into account a range of variables, including; the length of mains that feed out from the gate stations; the odorant injection rate; and the leak history at the gate stations. Allgas expected the number of repairs to decline beyond 2006-07. ECG acknowledged that the changes to odorisation would result in an increased requirement for repair work. In light of this more detailed explanation, ECG considered that the revised forecast expenditure for corrective maintenance, inclusive of changes as a result of the reduction in the cased crossing rectification program, to be appropriate. The Authority considers that ECG's recommended forecasts for these costs are in accordance with the Code.

Allgas forecast customer service costs to rise gradually over the next regulatory period reflecting an increase in meter readings and customer inquiries as the network grows. ECG regarded these forecast costs to be reasonable, considering the cost per customer is commensurate with other jurisdictions. On this basis, the Authority considers that Allgas' forecast customer service costs are in accordance with the Code.

Maintenance planning and support costs relate to fees and charges and the labour costs associated with maintenance programs, compliance reporting and the Meter Measurement Scheme. The costs include payments to the Queensland Departments of Energy and Natural

Resources and Mines for both licence fees and gas safety fees. Costs for this category show an overall decreasing trend, with a significant drop from 2007-08 onwards due to a reduction in staffing levels. ECG regarded the trends and overall forecast cost of maintenance planning and support to be consistent with a prudent service provider acting efficiently. As a result, the Authority considers that Allgas' forecast maintenance planning and support costs are in accordance with the Code.

ECG's assessment of Allgas' non-capital costs incorporate ongoing cost reductions in operating and maintenance and administration costs (excluding corrective maintenance). Prior to the Authority's Draft Decision, this represented around 2.5 per cent each year. Following ECG's revised assessment of Allgas' non-capital costs, the ongoing cost reductions represent around 1.85 per cent each year. ECG noted that the ongoing cost reductions were consistent with that experienced in other jurisdictions. As a result, the Authority accepts that appropriate ongoing cost reductions have been included in Allgas' forecast non-capital costs.

#### Network development

Network development includes marketing activities such as working with property developers to maximise the uptake of gas services, promoting the safe use of natural gas and increasing the utilisation of the network by improving public awareness of the advantages of using natural gas. In 2001, the Authority approved network development expenditure of \$420,000 each year across the current access arrangement period.

ECG examined Allgas' network development expenditure over the current access arrangement period. ECG noted that the cost primarily covered the direct and indirect costs for four employees. No incentives or other inducements were offered to customers as part of Allgas' network development expenditure. ECG observed the cost of network development was higher in some years during the current regulatory period than was forecast in 2001. For example, \$540,000 was spent in 2002-03 and \$650,000 in 2003-04. However, no particular explanation of the higher expenditure was provided by Allgas.

Allgas proposed to continue with its current range of network development activities over the next regulatory period and has forecast future costs at \$600,000 each year. Allgas claimed the increased cost was required to fund the existing program based on expenditure during the current access arrangement period. However, in the absence of information to justify the cost increase, ECG suggested that network development costs should be maintained at the current level (that is, decreasing in real terms) included in the 2001 access arrangement.

Allgas' network development activities during the current access arrangement period appear to have contributed to increased network growth over the current access arrangement period. As the costs of this activity are largely related to labour costs, the Authority accepts that a real cost reduction may not allow the program to be continued at its current level. Were the \$420,000 included at the start of the last access arrangement period (and held constant throughout the period) inflated to maintain its real value across the current access period and into the next, the amount would not be all that different at the end from the (constant) \$600,000 requested by Allgas for each year of revised access arrangement period. Given Allgas' past efforts and expenditure in this area, combined with the apparent growth that has been achieved, the Authority accepts the increase that Allgas has forecast. The Authority's position on this matter has not changed from the Draft Decision.

#### Ancillary services

Allgas has forecast that ancillary services (which include items such as special meter readings) will remain at approximately the same unit cost as in the current access arrangement period. However, the total cost for these services is forecast to generally rise over the period in real

terms due to the forecast increase in customer numbers. ECG considered these costs to be prudent and in accordance with the Code. The Authority accepts Allgas' forecast ancillary costs.

#### Summary

Based on its analysis, ECG recommended overall non-capital expenditure forecasts as summarised in Table 13.2.

**Table 13.2: ECG forecast non-capital expenditure (excluding UAG) 2006-07 to 2010-11 (\$m, nominal)**

<i>Type of Cost</i>	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Inspection	1.29	1.73	1.73	1.83	1.72
Planned Maintenance	3.04	3.03	3.00	2.67	2.82
Corrective Maintenance	2.52	2.46	2.34	2.03	1.87
Customer Service	0.99	0.99	1.08	1.17	1.25
Maintenance Planning & Support	2.48	2.27	2.35	2.33	2.32
<b>Total operating and maintenance</b>	<b>10.32</b>	<b>10.48</b>	<b>10.50</b>	<b>10.03</b>	<b>9.98</b>
Network Development	0.42	0.43	0.45	0.46	0.47
Ancillary Services	0.60	0.59	0.68	0.78	0.77
<b>Total</b>	<b>11.34</b>	<b>11.50</b>	<b>11.63</b>	<b>11.27</b>	<b>11.22</b>
<b>Allgas Total</b>	<b>12.00</b>	<b>12.00</b>	<b>12.00</b>	<b>11.80</b>	<b>11.80</b>

The Authority has considered both Allgas' non-capital cost forecasts and ECG's comments on those forecasts for each of the categories above. In most cases, the Authority has accepted Allgas' forecasts based on ECG's recommendations.

Table 13.3 shows the Authority's revised non-capital costs for Allgas over the forecast period. Over the next access period, these forecasts total \$52.4 million, 6.6 per cent lower than Allgas' proposed forecasts.

**Table 13.3: Forecast non-capital expenditure (excluding UAG), 2006-07 to 2010-11 (\$m, nominal)**

<i>Type of Cost</i>	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Inspection	1.29	1.73	1.73	1.83	1.72
Planned Maintenance	3.04	3.03	3.00	2.67	2.82
Corrective Maintenance	2.52	2.46	2.34	2.03	1.87
Customer Service	0.99	0.99	1.08	1.17	1.25
Maintenance Planning and Support	2.48	2.27	2.35	2.33	2.32
Network Development	0.60	0.60	0.60	0.60	0.60
Ancillary Services	0.60	0.59	0.68	0.78	0.77
<b>Total</b>	<b>11.52</b>	<b>11.67</b>	<b>11.78</b>	<b>11.41</b>	<b>11.35</b>
<b>ECG Total</b>	<b>11.34</b>	<b>11.50</b>	<b>11.63</b>	<b>11.27</b>	<b>11.22</b>
<b>Allgas' Total</b>	<b>12.00</b>	<b>12.00</b>	<b>12.00</b>	<b>11.80</b>	<b>11.80</b>

**Amendment 13.1**

**In order for Allgas' access arrangement to be approved, Allgas must amend its forecast non-capital costs (excluding UAG) over the next regulatory period in accordance with Table 13.3.**

**13.4 Unaccounted for Gas**

Unaccounted for gas (UAG) is defined as the difference between the quantity of gas delivered into and withdrawn from a network in a given period. Unaccounted for gas is primarily the result of:

- physical losses – as a result of leakage, third party intervention or planned maintenance (such as the purging of new mains); and
- apparent losses – resulting from meter inaccuracies and accounting procedures. Perhaps the main contributor to apparent losses is that not all meters can be read at the same time.

Many factors influence the level of physical losses such as gas pressure, the temperature of the surrounding environment, gas composition, and the age and condition of the network.

The Code requires the Authority to ensure reference tariffs are based on efficient costs not actual costs. In its 2001 Final Decision, the Authority gave detailed consideration to the issue of UAG as it believed that the level of UAG on both the Allgas and Envestra networks was unacceptably high. The Authority reasoned that, as it had established a capital base consistent with a depreciated network built using modern equivalent methods, that the acceptable level of UAG should also be determined on this basis. Consequently, the Authority included forecast costs for UAG that were less than that forecast by the service providers at the time.

*Allgas' proposal*

Allgas have argued that reducing UAG is not an end in itself but rather it is a residual outcome of both network renewal and maintaining network safety. Allgas has identified areas of network renewal that have resulted in UAG falling over the current access arrangement period to the

benchmarks set by the Authority in its 2001 Final Decision. Allgas has amended its forecasts of UAG for the next access arrangement period (see Table 13.4) consistent with its amended revised access arrangement. Allgas has noted that these forecasts are tied to the outcome of its proposed capital expenditure program and in particular, its mains renewal programme.

Allgas has claimed confidentiality over UAG unit costs. However, evidence of price paid by Allgas for UAG has now been provided to the Authority on commercial-in-confidence basis.

**Table 13.4: Allgas’ forecast UAG, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
UAG	1.4	1.3	1.1	1.0	0.8

#### *Other jurisdictions*

ICRC (2004) required ActewAGL to achieve a UAG benchmark rate of 1 per cent of throughput and a price of \$2.50/GJ. Cost incurred above this amount would not be compensated while costs below this would be retained by the service provider.

IPART (2005) required AGLGN to achieve 2.2 per cent UAG rate of loss in the first three years of the next regulatory period, falling to 2.1 per cent for the last two years. IPART considered that as older distribution pipes were replaced, UAG levels would decline as well.

#### *Submissions from stakeholders*

EUAA (2006) noted that the Authority requested that Allgas provide more information to determine the efficient costs for UAG. EUAA sought a clear rationale for any changes to the Draft Decision in this matter.

#### *QCA position*

##### Draft Decision

The Authority discussed in detail the issue of UAG in its 2001 review of access arrangements for Allgas and Envestra. It was clear at that time that the Queensland networks had materially higher levels of UAG than other networks in Australia. In its 2001 Final Decision, the Authority examined the level of UAG on other distribution networks and included a cost for UAG based on an average loss across those networks. The benchmark developed by the Authority at that time recognised the different characteristics of high and low pressure parts of the networks and resulted in a benchmark UAG rate of 3 per cent of total gas throughput for Allgas. The costs of UAG accepted in the 2001 Final Decision were based on this benchmark rate.

In its Draft Decision, the Authority stated that it would review the benchmark UAG rate for the Queensland networks before reaching a final decision on forecast UAG for their revised access arrangements.

Allgas has stated that its UAG, as a proportion of total gas throughput, fell from 4.7 per cent in 2001-02 to 3.3 per cent in 2004-05. Further reductions in UAG were forecast by Allgas in the future. ECG, working off Allgas’ stated UAG results, also forecast declining UAG in the future but at a less rapid rate, reflecting ECG’s recommendation that Allgas’ forecast network renewal program be scaled back.

At the time of the 2001 Final Decision, Allgas estimated UAG to be 5.5 per cent of total throughput (based on 2000-01 data). This is somewhat inconsistent with the historical information it has provided now. For this reason, in its Draft Decision, the Authority did not accept that either Allgas or ECG forecasts necessarily represented best estimates. Allgas was required to review the UAG information it provided to the Authority to confirm historical levels of UAG.

#### Final Decision

In response to the Authority's concerns, Allgas provided additional information to demonstrate to the Authority that its revised volumes of UAG in 2000-01 and subsequent years were appropriate. These historical figures were used to forecast UAG levels over the next regulatory period.

In order to assess Allgas' expected levels of UAG for the next access arrangement period and those levels that would be considered efficient, the Authority commissioned ECG to review the benchmark UAG rate. ECG compared the Queensland networks with other networks in Victoria, New South Wales and the Australian Capital Territory. ECG suggested that UAG per length of mains replaced would be a better guide to UAG performance than using a benchmark based on UAG as a proportion of throughput as the Authority had done in 2001, as the 'leakiness' of mains is not affected by throughput. ECG found that the Queensland network's UAG losses as a percentage of throughput, which are high compared to other jurisdictions, reflected the lower volume of gas consumed by residential customers, which typically account for nearly all of UAG. However, when UAG losses were measured against an alternative measure, the losses were more comparable.

Using Allgas' UAG data from the current period, ECG calculated that Allgas' UAG declined by 478GJ per km of mains replaced. ECG has advised that Allgas' improvement in UAG of 478GJ per km of mains replaced compares favourably with networks in other jurisdictions.

The Authority accepts that use of benchmarks set on a loss per km of mains replaced should be more robust than a benchmark set on a throughput basis. The Authority notes that forecast UAG levels for Allgas, as assessed by ECG, are comparable to those in other jurisdictions. On this basis the Authority does not intend to cap the UAG costs incurred by Allgas as it did in 2001.

However, ECG forecast a slower decline in aggregate UAG than did Allgas, reflecting the slower rate of network renewal accepted by the Authority.

In order to establish the forecast cost of UAG over the next access arrangement period, the price of gas is required. In its Draft Decision, the Authority required Allgas to provide evidence to support its claimed gas prices over the forecast period. Allgas has subsequently provided this evidence on a commercial-in-confidence basis to the Authority. The forecast cost of UAG for the next access arrangement period was calculated using ECG's recommended forecast volume of UAG and the price of gas advised by Allgas. Table 13.5 shows the forecast cost of UAG that the Authority has accepted.

**Table 13.5: Forecast UAG, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	209-010	2010-11
UAG	1.5	1.4	1.4	1.3	1.2

**Amendment 13.2**

**In order for Allgas' access arrangement to be approved, Allgas must amend its forecast UAG over the next access arrangement period in accordance with Table 13.5**

**13.5 Taxation**

In its Decision on the 2001 access arrangements, the Authority accepted the forecast cost of tax supplied by each service provider at the start of the regulatory period based on the requirement that this would be adjusted at the end of the regulatory period to bring those forecasts into line with actual tax paid. The Authority made this position quite clear in both its Draft Decision and in its Final Decision.

*Allgas' proposal*

In its initial revised access arrangement information, Allgas reduced its proposed revenue for the next access arrangement period by \$1.5 million to account for the fact that its actual tax paid during the current access arrangement period was less than that which was forecast at the start of the period. Allgas accepted this adjustment was in line with the currently approved access arrangement and with the Authority's stated requirement in its Draft and Final Decisions on the current access arrangement. Following the Authority's Draft Decision, Allgas has removed this tax adjustment from proposed revenue in its revised access arrangement information.

Allgas also provided forecasts of actual tax for the next regulatory period based on the same methodology used by the Authority in its Draft Decision on Envestra's revised access arrangement. In its initial access arrangement information, Allgas had based its tax forecasts on an allocation to Allgas of a share of the Energex Group tax liability, based on Allgas' share of the Energex Group's Earnings Before Interest and Tax. Allgas did not provide any information on how the Energex Group forecasts were calculated. The regulatory tax forecasts provided by Allgas in its amended revised access arrangement were adjusted to reflect a value for gamma of 0.50 (previously 0.35) as required by the Authority. Allgas' forecast of regulatory tax is shown in Table 13.6.

Allgas also noted that it was its understanding that the tax forecasts would be revisited at the end of the next regulatory period to account for the actual building block cost outcomes.

**Table 13.6: Allgas' Forecast tax, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Forecast Tax	2.4	2.5	2.7	2.9	3.1
Regulatory tax	1.2	1.3	1.3	1.5	1.6

*Other jurisdictions*

Several regulators (including, IPART, ERA, ICRC and ESCOSA) use a pre-tax WACC that accounts for tax within the WACC model. Others (ESCV, ACCC and the Authority) use a post-tax WACC and recognise the cost of tax in the cash flows.

The ESCV (2002) used a post-tax version of WACC for the gas distributors in Victoria. The view of the ESCV was that the allowance for company taxation should reflect an unbiased forecast of the taxation liabilities for an efficient company. ESCV adopted its own industry-wide benchmark assumptions for many of the tax inputs on the basis of independent

professional tax advice. Many of the inputs used were required for the assessment of reference tariffs, including assessable revenue, operating expenditure, capital expenditure and interest expenses. The taxation that was allowed in the building blocks was not reconciled against actual tax paid by the company and no adjustment was made on an ex-post basis.

The ACCC (2003) considered that a key objective in determining the allowance for taxation was that it reflected an unbiased estimate of tax liabilities for an efficient company. The ACCC used a post-tax nominal framework and included tax in the cash flows. The ACCC used some of the inputs from the regulatory framework to deduce likely tax liabilities for the regulated entity. The ACCC also used information on the tax position of the regulated business, information to determine depreciation allowances, an assumption regarding the company tax rate and an assumption regarding imputation credits facing the benchmark firm to determine a tax liability to be included in the cash flows.

#### *Submissions from stakeholders*

EUAA (2006) noted that the Authority requested that Allgas provide more information to determine the efficient tax forecasts. EUAA sought a clear rationale for any changes to the Draft Decision in this matter.

#### *QCA position*

The Authority has set a post-tax WACC for Allgas' next access arrangement period (see Chapter 12). As a result, an allowance for regulatory tax needs to be determined.

#### *Draft Decision*

As stated previously, it was the Authority's intention that there would be an adjustment in setting revenue for the next regulatory period to account for any differences between forecast tax and actual tax during the current regulatory period. Allgas recognised this requirement in its initial revised access arrangement. Allgas had deducted \$1.5 million from its future revenue to reflect the additional revenue it raised from its customers during the current access arrangement period, due to the forecast tax at the start of the period (that was included in the revenue to be raised during the period) being greater than the amount of tax actually paid by Allgas. In short, Allgas proposed to return to customers a windfall gain achieved during the current regulatory period.

Had the balance of forecast and actual tax been reversed, Allgas would have been entitled to raise the shortfall by increasing its revenue during the next regulatory period.

However, despite the clearly stated intention of the Authority that such an adjustment would be made, Envestra argued that retrospective adjustments are inconsistent with the price path form of regulation which underpins the approved access arrangement and that the wording of its current (approved) access arrangement did not support such an adjustment being required.

The Authority took legal advice on this matter in relation to Envestra. That advice suggested that the Authority's intent as detailed in its 2001 Draft and Final Decision was not fully reflected in the wording of Envestra's access arrangement as subsequently approved by the Authority. In light of this unexpected situation, the Authority considers that to require Allgas to proceed with this adjustment, while Envestra is able to retain its windfall gain, would be inequitable. In its Draft Decision, the Authority therefore elected not to require Allgas to make any adjustment to future revenue to reflect past differences between forecast and actual tax paid.

In light of the events discussed above, the Authority had to reassess its approach to tax for the next access arrangement period. For the purposes of its Draft Decision, the Authority accepted Allgas' method of calculating forecast tax by an apportionment of the Energex Group's forecast actual tax, as it was not possible to separately identify the actual tax that is paid by the regulated business because Allgas is part of a consolidated entity. The Authority was of the view that this method would provide a reasonable forecast of the actual cost of tax and that it was Code compliant. However, in its Draft Decision, the Authority did adjust the forecasts of tax provided by Allgas to reflect the Authority's accepted gamma of 0.5, rather than 0.35 as proposed by Allgas. Also, the Authority noted that Allgas did not provide sufficient information in its access arrangement or access arrangement information for the Authority to be comfortable with the specific forecasts of tax for the consolidated entity provided by Allgas.

As a result, the Authority required Allgas to either demonstrate that the forecasts of consolidated actual tax and the forecasts of the EBIT proportions had been made on a reasonable basis or include a mechanism in its access arrangement that would require an adjustment in the next access period for the difference between forecast tax and actual tax.

#### Final Decision

In response to the Authority's Draft Decision, Allgas amended its method of calculating forecast regulatory tax for the next access arrangement period to align it with the general approach used by Envestra (and accepted by the Authority) to forecast regulatory tax. That is, applying the statutory tax rate (30 per cent) to the forecast revenue of the service provider (based on the cost building blocks accepted by the Authority) and using the value of gamma (0.50) accepted by the Authority (see Chapter 12). Allgas has estimated its forecast regulatory tax based on the cost components in the revenue requirement proposed by Allgas. Allgas also accepted the tax forecast would be subject to reconciliation at the end of the next regulatory period to make an adjustment for actual 'building block' outcomes.

The Authority has reconsidered its requirement for a reconciliation of tax at the end of the next access arrangement period. Given the cost of tax is a residual calculation based on a number of the 'building block' components already accepted as best estimates, the Authority has decided that an ex-post adjustment to regulatory tax for Allgas is not required.

As a result, the Authority accepts Allgas' revised approach to forecasting regulatory tax and accepts this on a 'set and forget' basis. However, the Authority has adjusted Allgas' forecasts of tax to reflect the revenues and costs that the Authority has accepted for the purposes of this Final Decision. For the purpose of calculating tax depreciation, the Authority has used regulatory depreciation as this is consistent with the approach to calculating the cost of tax using the 'building blocks'.

Forecast tax and forecast regulatory tax which takes account of gamma, are shown in Table 13.7.

**Table 13.7: Forecast tax, 2006-07 to 2010-11 (\$m, nominal)**

	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Forecast Tax	2.8	2.7	2.8	3.2	3.5
Regulatory tax	1.4	1.3	1.4	1.6	1.8

**Amendment 13.3**

**In order for Allgas' access arrangement to be approved, Allgas must include the forecast cost of tax as outlined in Table 13.7.**

## 14. GAS DEMAND FORECASTS

*The Authority has considered the gas demand forecasts submitted by Allgas in light of independent forecasts it has commissioned. The forecasts that were commissioned by the Authority differed in some areas to the forecasts that were submitted by Allgas. The Authority considers that Allgas is unlikely to overstate demand growth, given the consequences that this would have in terms of revenue and pricing.*

*The Authority has considered whether the forecasts arrived at by Allgas are best estimates made on a reasonable basis. The Authority has assessed the Allgas forecasts and the associated methodology and has compared these with the forecasts and methodology of its independent expert McLennan Magasanik Associates (MMA).*

*In its Draft Decision, the Authority required Allgas to make some amendments to its gas demand forecasts for both volume customers and demand customers. Allgas amended its revised access arrangement for volume customers but has provided further arguments in support of its forecasts for demand customers. The Authority re-engaged MMA to consider the additional information provided by Allgas and to update its forecasts of demand if necessary.*

*The Authority has reviewed the information provided by Allgas and the revised MMA forecasts and has decided to accept Allgas' forecasts of MDQ for its demand customer class.*

### 14.1 Introduction

The forecasts of gas demand over the access arrangement period are important inputs in the process of setting reference tariffs. As such, it is necessary for the Authority to determine whether estimates of the quantity of gas to be demanded by customers over the period of the access arrangement are reasonable.

### 14.2 Code Requirements

Section 8.2(e) of the Code requires that the Authority be satisfied that any forecasts required to set reference tariffs represent best estimates arrived at on a reasonable basis. The Authority must also consider the objectives in section 8.1 of the Code when determining the Reference Tariff and Reference Tariff Policy.

### 14.3 Determining Gas Demand Forecasts

Reference tariffs are set using assumed levels of gas demand over the next access arrangement period. If these forecasts are too high, the resultant tariffs will be lower than those necessary to achieve the forecast revenue requirement. Conversely, if forecasts are too low, prices will be set higher than those necessary to raise the forecast revenue requirement.

In considering their forecasts, service providers would be more likely to underestimate demand, to ensure that they achieve or exceed their revenue target, than to overestimate demand. Service providers will have a natural incentive to exceed the forecast growth of the market during the access period since their efforts in this regard will result in revenue over and above that necessary to meet the full economic cost of service delivery.

The Authority's task is therefore to determine the most robust demand forecasts that recognise the service providers' revenue requirements while maintaining incentives to grow the market.

*Allgas' proposal*

Allgas has provided separate forecasts for volume customers and demand customers for each year of the next regulatory period (see Tables 3.4 and 3.5 of Allgas' initial revised access arrangement information). Allgas has noted that there are several possible new sources of gas that may come on-stream in the near future. However, for the purposes of the demand forecasts, it has assumed that no new source of gas will become available before 2011.

With regard to volume customers, Allgas' network development plan aims to attract residential customers by ensuring that new residential developments include natural gas connections that take both cooking and hot water. Allgas has noted that the network will only be expanded where natural gas will have close to a 100 per cent penetration rate into new residential developments. Allgas has constructed its residential forecasts based on a 'bottom-up' assessment of demand, determined by forecasting the actual numbers and timing of new residential connections expected to emerge as a result of agreements with developers.

To convert connections to volume of gas, Allgas noted that consumption of natural gas by residential households ranges from 0 GJ to 25 GJ each year. However, as maximum consumption is largely confined to the Toowoomba region due to the cooler climatic conditions, Allgas has used an average consumption figure of 13.6 GJ each year for residential consumers.

Allgas amended its forecasts for residential customers in its revised access arrangement to reflect the amendment required by the Authority in its Draft Decision, as shown in Table 14.1.

**Table 14.1: Allgas' gas demand forecasts for volume customers, 2006-07 to 2010-11 (TJ)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Residential	1,009	1,039	1,072	1,109	1,153
Commercial	1,974	2,052	2,139	2,230	2,323
<b>Total</b>	2,983	3,091	3,211	3,339	3,476
Growth (%)	3.5	3.7	3.9	4.0	4.1

For commercial and small industrial (non-residential consumption less than 10 TJ per annum) customers, Allgas has forecast growth in line with its network development plan and has assumed average usage of 420 GJ per year per customer.

With regard to the forecasts for demand customers, Allgas noted that there are currently 111 demand customers with gas consumption over 10 TJ each year. Allgas has forecast a net gain of a single large customer for each year of the access arrangement period.

Allgas noted that actual demand customer growth has averaged 0.2 per cent per annum (to 2004-05) despite the economic growth rate for Queensland being much higher than this. Allgas has forecast growth in consumption for existing demand customers by adopting the following assumptions:

- the total growth in gas deliveries to demand customers is assumed to be 1 per cent per annum on the network;
- that MHQ will remain constant to 2010-11; and
- that MDQ will grow at 1 per cent per annum across the network.

While the Authority required Allgas to amend its forecasts for demand customers in its Draft Decision, Allgas has argued that the concerns raised by the Authority in its Draft Decision were misguided.

Allgas disputed MMA’s assumption that the load factor will continue to decrease over the next regulatory period. Allgas suggested that an observed network wide decline in load factors can be attributed to higher calculated MDQ within the existing customer group and low load factors for new customers whose consumption data does not reflect a full year of consumption while its MDQ does. Allgas suggested that the assumption of a continually decreasing load factor cannot be verified and is, therefore, not appropriate.

Based on 1 per cent growth in annual demand from 2000-01 to 2005-06 and a constant load factor, Allgas suggested that its existing forecasts for demand customers were best estimates arrived at on a reasonable basis. Allgas’ forecasts for demand customers over the next regulatory period are shown in Table 14.2.

**Table 14.2: Allgas’ gas demand forecasts for demand customers (consumption and MDQ), 2005-06 to 2010-11**

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
Consumption (TJ)	7,324	7,355	7,443	7,533	7,623	7,714
Growth (%)		0.4	1.2	1.2	1.2	1.2
MDQ (GJ)	30,544	30,345	30,628	31,022	31,418	31,817
Growth (%)		-0.6	0.9	1.3	1.3	1.3

#### *Other jurisdictions*

IPART (2005) engaged an independent expert to assess the methodology used by AGL to determine its gas demand forecasts, and to make recommendations to assist the Tribunal in determining whether the forecasts were best estimates arrived at on a reasonable basis. The tribunal required AGL to make some amendments to its gas demand forecasts.

The ESCV (2002) required that the distributors submit their own gas demand forecasts together with independent verification that the forecasts were ‘the best estimates arrived at on a reasonable basis’. The Commission then assessed the forecasts in light of other additional evidence and required the distributors to make some adjustments to their demand forecasts.

ICRC (2004) engaged an independent consultant to assess whether the ActewAGL forecasts were best estimates arrived at on a reasonable basis. The consultant also prepared its own forecasts because it did not believe that ActewAGL’s forecasts were appropriate. The Commission required ActewAGL to make adjustments to various aspects of its gas demand forecasts.

ESCOSA (2006) engaged an independent consultant to assess whether the Envestra forecasts were best estimates arrived at on a reasonable basis. The consultant also provided its own set of forecasts. ESCOSA accepted some aspects of Envestra’s forecasts, but required that it make some amendments and incorporate some of those forecasts developed by the consultant.

### *Stakeholder comments*

In response to the Authority's Draft Decision, the EUAA (2006) expressed concern that the distributors would try to overstate demand growth and therefore supported the Authority's use of many of the MMA forecasts.

In a joint submission, Origin Energy and Ergon Energy (2006) provided information on a prospective new large consumer in the Toowoomba region and suggested that this should lead to a reduction in tariffs in the Toowoomba region.

### *QCA position*

#### Draft Decision

The Authority commissioned McLennan Magasanik Associates (MMA) to develop an independent set of gas demand forecasts for Queensland to assist the Authority in forming an opinion on the reasonableness of the forecasts submitted by Allgas and Envestra. Prior to the Draft Decision, MMA produced a separate report for each network which can be found on the Authority's website. MMA's forecasts were disaggregated on the basis of customer class, region and maximum daily quantity (MDQ) where appropriate.

The information on which MMA based its forecasts for Allgas included:

- historical information supplied by Allgas;
- information and forecasts available in the public arena; and
- a telephone survey of Allgas' largest customers.

The approach taken by MMA was to:

- separate demand into reasonably homogenous market categories, in this case residential, small business (commercial and small industrial) and large industrial;
- consider the important markets or sub-components of markets. For the residential and small business markets, this was the number of connections and the average usage (including serviced hot water for the residential market). For the large customer market total usage and MDQ was used;
- assess trends over recent years and examine changes to key drivers;
- conduct a survey of the largest customers;
- forecast the residential, small business and large industrial markets separately; and
- disaggregate demand into demand and volume customer groups, which are the basis of the proposed reference tariffs, and into zones as appropriate.

MMA used the above approach to develop forecasts of demand for the Allgas distribution network from 2005-06 through to 2010-11.

MMA forecast the domestic market in two segments, the residential market and the serviced hot water (SHW) market. For each segment, an assessment was made of both customer numbers and average usage. MMA forecast customer numbers to grow for the residential market, based on the forecast growth in residential dwellings, but forecast average usage to decline.

Nonetheless, the residential market was forecast to increase total consumption over the period. The SHW market was forecast to increase in size and also in average usage. MMA then combined these two segments and forecast total domestic load to increase from 950 TJ in 2005 to 1153 TJ in 2011. This implies a growth rate of around 3.3 per cent each year.

MMA assessed the commercial and small industrial market (less than 10 TJ per annum) by using a combination of regression analysis against both time and Gross State Product (GSP). MMA has forecast consumption in this sector to increase from 1792 TJ in 2005 to 2346 TJ in 2011. This represents an increase of around 4.6 per cent each year. These forecasts were similar to those provided by Allgas.

### Final Decision

In its March 2006 report to the Authority, MMA did not consider that there had been any material developments which would require changes to its previous forecasts for volume customers.

The MMA forecasts for Allgas' volume customer class are shown in Table 14.3.

**Table 14.3: MMA forecasts for Allgas volume customers, 2005-06 to 2010-11 (TJ)**

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
Residential	979	1,009	1,039	1,072	1,109	1,153
Commercial	1,854	1,977	2,087	2,171	2,260	2,346
<b>Total</b>	<b>2,833</b>	<b>2,986</b>	<b>3,126</b>	<b>3,243</b>	<b>3,369</b>	<b>3,499</b>
Growth (%)		5.4	4.7	3.7	3.9	3.9

In its Draft Decision, the Authority noted that the Allgas' forecast growth rate for residential customers and the MMA forecast growth rate were very similar and the main difference between the respective consumption forecasts was due to a different starting value. However, it became apparent that Allgas had slightly miscalculated its starting value and, as such, the Authority required Allgas to adopt the MMA forecasts for residential consumption. Allgas accepted this amendment and has updated its revised access arrangement accordingly.

In its Draft Decision, the Authority noted that the forecasts for commercial and small industrial (< 10 TJ consumption per annum) customers provided by Allgas were very similar to those that had been arrived at by MMA. This was despite the fact that Allgas used a bottom-up approach to forecasting consumption for this class of customer and MMA used a regression analysis against time and GSP. Given the similarity of the result, the Authority was satisfied that the methodology used by Allgas was appropriate and that Allgas' forecast for commercial and small industrial customers met the requirements of the Code.

For the calculation of reference tariffs, the Authority accepts the volume forecasts contained in the amended version of Allgas' revised access arrangement.

For the demand class of customers (those that consume over 10 TJ per year), it is MDQ that is important from a pricing and network development perspective. MMA has forecast MDQ growth separately for Brisbane, the South Coast and Toowoomba.

In its response to the Draft Decision, Allgas argued that the assumption made by MMA of a declining load factor was incorrect and suggested that it was more appropriate to assume a constant load factor. In its review of its original forecasts, MMA noted that the information previously provided by Allgas had been incomplete in that, while consumption for all demand

customers was included by year, historical MDQ information was provided only for customers who were still taking gas in 2004-05. MMA noted that, while the original data provided by Allgas inferred a falling load factor, the corrected data now suggested load factor was not changing over time. Consequently, MMA has assumed the load factor to be constant in its updated demand forecasts.

Given the revisions to its assumptions about load factors, and having taken into account information obtained since its original report, MMA has forecast MDQ to grow from 29,930 GJ in 2005 to 33,520 GJ in 2011. These forecasts include an extra 467 GJ per year in the Toowoomba region to take into account of the increases in MDQ suggested in the Ergon/Origin (2006) submission. The MMA forecasts for MDQ for each Allgas zone and in total are shown in Table 14.5.

**Table 14.5: MMA forecasts of MDQ for Allgas (GJ)**

	<i>2005-06</i>	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Brisbane	23,500	24,080	24,560	24,900	25,250	25,580
South Coast	3,150	3,360	3,540	3,670	3,810	3,940
Toowoomba	3,710	4,010	4,010	4,010	4,010	4,010
<b>Total</b>	<b>30,360</b>	<b>31,440</b>	<b>32,110</b>	<b>32,570</b>	<b>33,070</b>	<b>33,520</b>
Growth (%)		3.6	2.1	1.4	1.5	1.4

The Authority is still concerned about the extent of the difference between the Allgas forecasts for MDQ and the MMA forecasts. The differences arise because Allgas assumed a much lower rate of growth for consumption than MMA. Allgas and MMA have differing views on the appropriate level of consumption in 2000-01, the starting point from which the subsequent trend is determined. This difference in the starting point is a likely cause of the different consumption forecasts.

If the consumption figure for 2000-01 was 7,247 TJ, as Allgas has suggested in its response to the Draft Decision, then the MMA forecasts of consumption are likely to be too high. The Authority sought assurance from Allgas that the figure that it has provided for 2000-01 is correct (which Allgas has confirmed). As such, it is reasonable to suggest that historic growth rates in consumption have been somewhat lower than those which were assumed by MMA.

MMA also included some additional MDQ in its forecasts based on the submission by Ergon/Origin Energy which suggested that a significant increase in MDQ in the Toowoomba region had been agreed to. This also explains part of the difference between the Allgas and MMA forecasts.

The Authority understands that commercial negotiations are still ongoing between Allgas and relevant parties and that determining the actual increase in MDQ, if indeed there will be any at all, is difficult. The Authority notes that average growth in MDQ over time is already factored into the forecasts prepared by Allgas and that there will always be some variation around those average values in any particular year.

Based on these considerations, the Authority accepts that the MDQ forecasts provided by Allgas for the demand customer class are best estimates arrived at on a reasonable basis.

## 15. REFERENCE TARIFFS AND TARIFF PATHS

*The Authority has assessed Allgas' proposed revenue targets and has forecast total revenue to be recovered over the next access period to be \$230.0 million. This compares to a total revenue forecast of \$162.6 million in the current access period.*

*The Authority has accepted Allgas' proposal to continue with two customer classes (demand and volume customers). The Authority has also accepted Allgas' basis for allocating costs across these two groups of customers and has apportioned total revenue on this basis. When converted into reference tariffs, the revised revenue requirements for each group suggest that prices for the demand customer group will change on average by CPI-0.2% each year while prices for volume customers will change on average by CPI each year.*

*In its Draft Decision, the Authority required Allgas to provide additional information to assist in evaluating the cost reflectivity of reference tariffs applied by Allgas to its different customer groups. The Authority's assessment of the information provided by Allgas suggests that, while some progress has been made over the current access period to increase the level of cost recovery from domestic consumers, a significant cross subsidy to small domestic customers remains. The Authority considers that Allgas should take more aggressive steps to remedy this situation over the next access period or risk an adjustment to revenues or the capital base in the future to ensure the cross subsidies are removed.*

*The Authority requires Allgas to amend its proposed side constraint for individual volume customers to CPI+3%. However, the Authority will consider any request by Allgas for price increases of more than CPI+3% to individual customers, or group of customers, where this will assist prices to those customer(s) to become more cost reflective.*

*The Authority is satisfied that, on the whole, demand customers are paying prices that are cost reflective.*

*In revising its reference tariffs and tariff paths, Allgas is required to incorporate the various amendments required by the Authority in this Final Decision.*

### 15.1 Introduction

Reference tariffs are the price for the service made publicly available by the service provider, upon which potential users can rely in making consumption and investment decisions. The reference tariffs for services to particular users depend on a number of factors, including:

- the total revenue the service provider is entitled to receive from the regulated services;
- the demand forecasts for the regulated services;
- the distribution of costs between different services and between different users of the same service; and
- any side constraints on prices charged to particular groups of users.

This chapter discusses the way total revenue is determined and how it is then translated into tariffs.

### *Code Requirements*

The Code (section 8.1) requires that certain key principles be reflected in the reference tariff policy of the service provider and in the calculation of all reference tariffs. These principles were discussed in Chapter 10.

Specific code requirements pertaining to the allocation of revenues between customers and prudent discounts are discussed in the relevant sections below.

## **15.2 Determination of Total Revenue**

In its Draft Decision, the Authority accepted Allgas' proposed 'cost of service' approach to determining annual revenue, coupled with a price cap approach to setting future prices.

Under the 'cost of service' approach proposed by Allgas, the total revenue requirement of a regulated business is determined by a number of factors, including:

- an appropriate rate of return on capital;
- a return of capital through depreciation; and
- non-capital costs of delivering the service, including tax and UAG.

The amounts proposed by Allgas for each of these factors have been discussed in previous chapters of this Final Decision. This section identifies the total revenue requirement for Allgas over the regulatory period 1 July 2006 to 30 June 2011.

### *Allgas' proposal*

While Allgas has used the method of calculating total revenue that was accepted by the Authority in its Draft Decision., Allgas' forecast of total revenue reflects the components of total revenue it has proposed in its amended revised access arrangement, as outlined in earlier chapters. Allgas' proposed total revenue target is summarised in Table 15.1.

**Table 15.1: Allgas' proposed total revenue targets, 2006-07 to 2010-11 (\$m, nominal)**

	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Return on capital	28.1	30.8	33.5	36.5	39.6
Capital appreciation	(8.7)	(9.6)	(10.4)	(11.4)	(12.3)
Return of capital (depreciation)	7.9	8.7	9.7	10.7	11.8
Non-capital costs	12.0	12.0	12.0	11.8	11.8
Unaccounted for gas	1.4	1.3	1.1	1.0	0.8
Regulatory tax	1.2	1.3	1.4	1.5	1.6
Ancillary service income	(0.6)	(0.6)	(0.7)	(0.8)	(0.8)
Capital contributions	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
<b>Total</b>	<b>41.0</b>	<b>43.7</b>	<b>46.3</b>	<b>49.1</b>	<b>52.3</b>

*Numbers may not add due to rounding.*

*Submissions from stakeholders*

In response to Allgas' revised access arrangement, Energex Retail (2006) raised a general concern that, in its view, the market would not sustain significant price increases.

*QCA position*

Total revenue, in the post-tax nominal framework used by the Authority, is calculated as follows. This approach is the same as that used for the Draft Decision.

$$TR_t = ROA_t - \Delta DRAB_t + D_t + Opex_t + UAG_t + T_t - OI_t$$

where:

$$ROA_t = WACC_{\text{post-tax}} * (DRAB_{t-1} + 0.5 * Capex_t)$$

$$\Delta DRAB_t = CPI_t * (DRAB_{t-1} + 0.5 * Capex_t)$$

and:

TR	=	Total Revenue
$WACC_{\text{post-tax}}$	=	Post Tax Nominal Weighted Average Cost of Capital
DRAB	=	Depreciated Regulatory Asset Base in nominal dollars
$\Delta DRAB$	=	Nominal change in DRAB
ROA	=	Return on Assets
D	=	Depreciation
Capex	=	Capital Expenditure
Opex	=	Operating Expenditure
UAG	=	Unaccounted for Gas
T	=	Tax payable (net of imputation benefit)
OI	=	Other income (e.g. capital contributions & ancillary services)
t	=	End of current year of regulatory period.

In determining the ROA, in addition to a return on the opening value of assets, a return was also allowed on half the value of forecast capital expenditure for each year. This assumes that capital expenditure occurs evenly during the year.

The  $\Delta DRAB$  component removes inflation-induced capital growth from the calculation of tariff revenues. It also assumes that capital expenditure occurs evenly throughout the year. As capital growth accrues to the service provider in the normal course of business, it is not included in the revenues used to determine reference tariffs. To do otherwise would constitute double counting and would be inconsistent with the Code.

Depreciation calculations also assume that capital expenditure occurs evenly throughout the year.

The Authority's calculation of the various components of the revenue requirement is discussed in the relevant chapters of this Final Decision.

Table 15.2 shows the breakdown of the component parts of total revenue for Allgas as determined by the Authority.

**Table 15.2: Total revenue targets, 2006-07 to 2010-11 (\$m, nominal)**

<i>Year end 30 June</i>	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
Return on capital	27.7	30.2	32.5	35.2	37.8
Return of capital (depreciation)	8.1	9.5	10.4	11.4	11.9
Non-capital costs	11.7	11.8	11.9	11.6	11.5
Unaccounted for gas	1.5	1.4	1.4	1.3	1.2
Tax (net of franking credits)	1.4	1.3	1.4	1.6	1.8
Disposals (2001-2006)	0.04	0.04	0.04	0.04	0.05
Less inflationary gain	8.8	9.5	10.3	11.1	12.0
Less capital contributions	0.5	0.5	0.5	0.5	0.5
Less income from ancillary services	0.6	0.6	0.7	0.8	0.8
<b>Total</b>	<b>40.6</b>	<b>43.6</b>	<b>46.2</b>	<b>48.6</b>	<b>51.0</b>

*Numbers may not add due to rounding. Figures are end-year values.*

The Authority's revenue requirements vary from those submitted by Allgas in its amended revised access arrangement, as follows

- the return on capital reflects a lower forecast level of capital expenditure than that proposed by Allgas;
- non-capital costs reflect the revised forecasts, which are less than those proposed by Allgas;
- the cost of unaccounted for gas has been increased to reflect a slower rate of mains renewal than that sought by Allgas; and
- capital contributions reflect forecasts provided by Allgas as well as an adjustment for contributions received in the current access arrangement period.

#### **Amendment 15.1**

**In order for Allgas' access arrangement to be approved, Allgas must revise its total revenue requirements for each year of the access arrangement period to those indicated in Table 15.2.**

### **15.3 Determination of Tariffs**

Having determined total revenue over the next access period, the remaining task is to translate these revenues into tariffs.

The Authority considers that it would be against the incentive objectives of the Code for it to become involved in the establishment of specific tariffs for different customer groups. Instead, the Authority is concerned with examining whether the form of regulation the service provider proposes and the principles they apply to revenue allocation are consistent with the Code. The Authority also focuses on the cost reflectivity of the prices proposed for broad groups of customers.

In general, the Authority considers a price cap should result in:

- volume risk being left with the service provider; and
- efficient price signals to users through cost reflectivity.

However, the specific details of a price cap's operation can significantly affect the incentives facing service providers (and customers). For example, and as discussed further below, the use of Maximum Daily Quantities (MDQ) as a pricing measure can significantly reduce the amount of volume risk that a service provider is exposed to.

To achieve cost reflectivity, tariffs should ideally be determined for each group of customers, as defined by location and customer consumption characteristics within a location. However, there are significant difficulties in attributing costs to specific groups of customers supplied by gas networks and there would also be significant administration costs in creating many customer groups. In short, the cost effectiveness of the level of precision that can be achieved in cost reflective pricing needs to be recognised.

In assessing the current access arrangement, the Authority accepted two weighted average price paths for Allgas customers. One for large (demand) customers, with volumes measured by MDQ, and one for small (volume) customers, with volumes based on per GJ consumption. The Authority also investigated sub-groups within the small customer group to determine whether prices for these customers were likely to be cost reflective.

#### *Code requirements*

Subject to section 8.40 (rebateable services) and 8.43 (prudent discounts), section 8.38 of the Code states that, to the maximum extent that is technically and commercially reasonable, the proportion of total revenue that a reference tariff should be designed to recover should include:

- a) all the total revenue that reflects costs incurred (including capital costs) that are directly attributable to the reference service; and
- b) a share of total revenue that reflects costs incurred (including capital costs) that are attributable to providing the reference service jointly with other services.

If the relevant regulator requires that a different methodology be used to determine the portion of total revenue to be recovered from particular reference tariffs than that proposed by the service provider, the regulator shall in its decision on the access arrangement provide a detailed explanation of the method that it requires be used to allocate costs.

Alternative approaches to allocating the costs may be used provided they are consistent with the requirements of the Code.

## **15.4 Tariff Paths for Demand and Volume Customers**

### *Allgas' proposal*

Allgas proposed the following principles for cost allocation and the determination of tariffs:

- **Cost Reflectivity** – The tariffs reflect a recovery of efficient costs associated with delivering the services of the network.
- **Efficient Pricing Signals** – The tariffs reflect economically efficient pricing principles. That is, the tariffs have been set so that they are between incremental and standalone cost benchmarks.

- Price Stability – Tariffs have been smoothed over the term of the access arrangement to avoid shocks in any year and provide stability and certainty for users.
- Replicating competitive market outcomes – The tariffs reflect the most efficient use of the distribution system resources. Assets are allocated to each tariff group according to the relative use by that customer group. Non-Capital costs are allocated to the appropriate assets and then to the tariff groups.
- Safe and reliable operation – Capital expenditure and non-capital cost forecasts are designed to deliver distribution network safety, reliability and integrity both in terms of design and operation. Users are entitled to the safe use of the distribution system and forecasts are designed to deliver benefits both in terms of reduced unaccounted for gas and more efficient operational and maintenance expenditure.
- Appropriate Investment Decisions – The tariffs provide efficient investment signals for the development and growth of the network. The tariff for demand customers is designed to avoid uneconomic duplication of the network and encourage an efficient use of resources. The fixed and variable components of tariffs have been designed to signal the most efficient use of assets and maximise utilisation of the network which will drive lower unit costs for the usage of such assets. This also results in a tariff which promotes an efficient network design to supply end users.

For the purpose of determining revised reference tariffs and associated tariff paths, Allgas assigned its target revenue to two customer groups as discussed in Chapter 10. Customers that fell into the volume customer group (less than 10 TJ group) ranged from very small domestic users (for example, those with a cooker only) through to medium sized commercial and industrial volume customers. Demand customers were those that consumed in excess of 10 TJ per year and are typically large commercial and industrial users. Allgas allocated revenue to these two groups on the basis of standalone costs for demand customers and the residual to volume customers.

To calculate the weighted average tariffs for each customer class, the revenue target for each customer class was divided by the forecast consumption of gas (see Table 15.3). Allgas smoothed the revenue target in order to achieve a price path over the revised access arrangement period that was consistent with CPI-X.

**Table 15.3: Allgas’ proposed revenue targets, 2006-07 to 2010-11 (\$m, nominal)**

	2006-07	2007-08	2008-09	2009-10	2010-11
Demand customers	11.9	12.3	12.8	13.4	13.9
Volume customers	29.1	31.0	33.1	35.5	38.0
<b>Total</b>	<b>41.0</b>	<b>43.4</b>	<b>46.0</b>	<b>48.8</b>	<b>51.9</b>

*Note: Allgas has smoothed the revenues in this table, compared to Table 15.1, where revenues proposed by Allgas are unsmoothed.*

Allgas’ weighted average reference tariffs (inclusive of GST) in 2005-06 are estimated to be:

- \$419.76 per GJ of MDQ for demand customers, and
- \$10.43 per GJ for volume customers.

For demand customers, Allgas proposed that the weighted average reference tariff increase over the forthcoming access arrangement period at the rate of inflation. That is, a price path of CPI.

In its amended revised access arrangement, Allgas proposed that the weighted average reference tariff for volume customers increase by 0.1 per cent each year over and above the rate of inflation for the forthcoming regulatory period, or CPI+0.1%. This rate of increase is less than that proposed by Allgas in its initial revised access arrangement. Allgas also proposed a side constraint on price movements for any individual volume customer of CPI+3% or \$7 per year, whichever is the greater.

Allgas proposed that price adjustments for both customer classes would occur from the commencement of each contract year (typically 1 July).

#### *Submission from stakeholders*

In its response to the Authority's Draft Decision, the EUAA supported the Authority's requirement for two separate price paths for volume and demand customers. EUAA believed this was important in promoting accurate cost allocation between users.

#### *QCA position*

In its Draft Decision, the Authority adopted the allocation of costs between volume and demand customers proposed by Allgas in 2001. However, the Authority required further evidence to substantiate whether these allocations remained appropriate.

Allgas subsequently revised its allocations and provided detailed information on how the allocations were prepared and were consistent with the requirements of the Code. The Authority accepts Allgas' revised allocations.

Using the cost allocations proposed by Allgas and the revenue requirement forecast by the Authority, the target revenues for volume and demand customers can be derived as shown in Table 15.4

**Table 15.4: Forecast revenue targets, 2006-07 to 2010-11 (\$m, nominal)**

	<i>2006-07</i>	<i>2007-08</i>	<i>2008-09</i>	<i>2009-10</i>	<i>2010-11</i>
<b>Demand customers</b>	<b>11.8</b>	<b>12.4</b>	<b>12.9</b>	<b>13.3</b>	<b>13.7</b>
Percentage change	3.4%	5.1%	4.0%	3.3%	2.6%
<b>Volume customers</b>	<b>28.8</b>	<b>31.2</b>	<b>33.3</b>	<b>35.3</b>	<b>37.3</b>
Percentage change	6.8%	8.3%	6.7%	5.8%	5.9%
<b>Total</b>	<b>40.6</b>	<b>43.6</b>	<b>46.2</b>	<b>48.6</b>	<b>51.0</b>

*Numbers may not add due to rounding.*

On the basis of the revenue requirements for each customer class and the forecasts of gas demand as presented in Chapter 14, 'raw' prices can be determined for each year and for each customer class. To avoid price spikes that may be apparent in the 'raw' prices, the Authority has smoothed the 'raw' prices while maintaining the NPV of the total revenue across the period.

Based on this approach, the Authority has calculated that weighted average tariffs for demand customers will change by CPI-0.2% each year of the revised access arrangement period from an initial value of \$419.76 per GJ of MDQ in 2005-06. For volume customers, weighted average tariffs will change by CPI each year of the revised access arrangement period from an initial value of \$10.43 per GJ in 2005-06.

Allgas' proposed side constraint on tariffs for individual volume customers is assessed in the next section as it has implications for cost reflectivity.

**Amendment 15.2**

**In order for Allgas' access arrangement to be approved, Allgas must amend:**

- **the weighted average price path for demand customers to CPI-0.2% over the revised access arrangement period (with a value in 2005-06 of \$419.76 per GJ of MDQ);**
- **the weighted average price path for volume customers to CPI over the revised access arrangement period (with a value in 2005-06 of \$10.43 per GJ).**

**15.5 Cost Reflectivity**

Characteristics of infrastructure intensive network industries include:

- a high proportion of costs cannot be attributed directly to individual users of the network, making it difficult to apportion costs accurately between different users;
- high fixed costs make pricing solely on volumes volatile; and
- if all users paid marginal cost, the service provider would not cover total costs, rendering the service unsustainable.

To be economically efficient, the allocation of costs amongst groups of users should result in prices which reflect:

- at least the incremental costs associated with the provision of a service (or other users of the network would be better off if that customer was not supplied); and
- no more than the stand-alone cost of providing the service (or the user could potentially bypass the network and other users would lose their contribution to fixed costs).

Where prices do not fall within these broad boundaries, a cross-subsidy is said to exist. However, these boundaries are relatively wide and prices may vary significantly before a cross-subsidy is found.

*Code requirements*

Section 8.42 of the Code states that, subject to section 8.43, a reference tariff should, to the maximum extent that is technically and commercially reasonable, be designed so that a particular user's share of the portion of total revenue to be recovered from sales of a reference service (which may be on the basis of forecast) is consistent with the principles described in section 8.38.

*Allgas' proposal*

Allgas considered that it could achieve cost reflectivity within the price paths it had proposed. In addition, Allgas proposed a side constraint for volume customers, where the maximum annual increase in price for any individual end user, expressed in \$/GJ, would be limited to CPI+3% or \$7 per year, whichever was greater.

Subsequent to the Draft Decision, Allgas provided information to the Authority to assist in assessing the cost reflectivity of volume and demand customers.

### Volume customers

Allgas defined two incremental costs, long run incremental cost and short run incremental cost. Both measures of incremental cost include the direct costs of connecting and supplying a new customer to the network. However, long run incremental costs also incorporate indirect capital costs of supply, which is the contribution that a user makes to the cost of shared assets such as mains.

Allgas calculated the long run incremental costs of a new consumer by including costs for:

- a meter;
- a service;
- the average extension of a main; and
- related operating and maintenance costs.

On this basis, Allgas estimated the long run incremental costs to be \$224 per new domestic customer per year in 2005-06 or \$16.46 per GJ. Allgas calculated the short run incremental costs of a new domestic customer to be \$130 per customer, which excluded a contribution to shared asset costs.

Allgas indicated that, in 2005-06, the consumption level needed to recover long run incremental costs of supply from domestic customers was 13.3 GJ (down from 19.7 GJ in 2001-02). Allgas estimated that the average consumption of new domestic customers in 2006 was 13.6 GJ and will, therefore, generate sufficient incremental revenue to recover long-run incremental costs. According to Allgas, improvement over the current regulatory period stemmed from:

- a 22 per cent increase in the fixed charge;
- a 18 per cent increase in the volume charge for the first consumption block (0 to 9.3 GJ per year); and
- a 5 per cent increase in the volume charge for the second consumption block (9.3 to 620.5 GJ per year).

In addition, Allgas noted it had acted to address cost reflectivity by ensuring that:

- new domestic connections (in greenfield developments) maximise gas use by only building pipeline assets where developers agree to support the connection of gas hot water and cookers; and
- Allgas' capital program for mains renewal in existing network areas was supported by a strong marketing campaign to encourage domestic users to take more gas products, designed to improve the average consumption level.

Despite the overall result for domestic customers, Allgas conceded that it still has a large number of domestic customers whose incremental revenue is less than the long run incremental cost of supply.

Over the next access arrangement period, Allgas expected revenue from domestic customers to increase considerably as prices rise and average consumption continues to grow.

Allgas estimated that, when a domestic customer uses more than 4.1 GJ per year, the incremental revenue earned would exceed the short run incremental cost of supply and provide some contribution towards the long run incremental costs of supply.

Allgas estimated that the long run incremental cost to supply a commercial and industrial volume customer can be as low as \$224 per customer (where the customer uses similar services and meters to a new domestic customer) up to as high as \$3,500 per connection (depending on the customer's volume and distance from gas pipelines). Allgas argued that, for the majority of commercial and industrial customers, their incremental costs were the same as the incremental costs of new domestic customers and that few (if any) of these customers would be paying less than these long run incremental costs of supply.

Allgas estimated the stand-alone costs of a representative commercial customer consuming 4000 GJ per year to be \$26,139. Allgas indicated that the incremental revenue received from such a customer would be \$25,656, which is less than the stand-alone cost. Allgas noted that commercial and industrial customers generally have alternative energy options and for this reason concluded that no commercial and industrial customers were likely to be paying above their stand-alone costs.

#### Demand customer analysis

Allgas estimated two stand-alone costs for demand customers: a 'pure' stand-alone cost and a 'joint' stand-alone cost. 'Pure' stand-alone costs refer to the cost of assets and operating expenses for a customer at a particular location (without regard to other customers). 'Joint' stand-alone costs were calculated in a similar manner but included an allowance for the sharing of asset costs where customers are located close together. According to Allgas, joint stand-alone cost is a more realistic basis for calculating stand-alone costs because sharing of mains by customers in the same locality is common.

Allgas estimated the sum of all joint stand-alone costs to be \$14.6 million in 2005-06 although, given the theoretical nature of such an estimate, Allgas suggested a range from \$13.5 million to \$17 million would be appropriate.

Allgas noted that between 2001-02 and 2005-06, the revenue recovered from demand customers ranged between \$10 million and \$11 million. Based on its own forecasts, Allgas expected revenue to be recovered from demand customers would be \$11.9 million in 2006-07, which is below the joint stand-alone costs.

#### *Other jurisdictions*

ESCOSA (2006) required Envestra to recognise, in its estimate of stand-alone costs for demand customers, the economies of scale to be gained by connecting "clusters" of customers "naturally grouped together".

IPART (2005a) required Country Energy Gas to amend its proposed access arrangement to provide indicative price paths for each customer class and service, for each year of the proposed access arrangement period. Prices within these price paths were required to meet the weighted average price cap methodology and move tariffs towards cost reflective levels, while also managing customer impacts. In total, the cost reflectivity of prices charged to three groups of volume customers (industrial, commercial, residential and small business) and three groups of demand customers (Central, Bomen, Fringe) was investigated.

*Submissions from stakeholders*

Energex Retail stated that it supports cost-reflectivity of network charges and noted that the importance of this principle will increase under a full retail contestable (FRC) environment.

*QCA position*

In its Draft Decision, the Authority expressed its concern that cross subsidies may still be present within the volume customer class. Allgas had presented information prior to the Draft Decision regarding the cost reflectivity of tariffs for domestic customers (small volume customers) and demand customers. However, Allgas' analysis was incomplete as large volume customers had not been considered and no indication had been given as to the cost reflectivity of prices within the domestic customer group, as only averages were considered. The Authority required Allgas to address these gaps in its response to the Draft Decision.

As noted earlier, efficient prices will fall in the range between the incremental and stand-alone costs for providing the service. In practice, this range of efficient prices can be wide. In the Authority's experience, demand customers typically cover their incremental cost of supply, given their greater ability to pay. The concern for these customers is therefore whether the prices they are being charged exceed the efficient stand-alone cost of supply. If charges do exceed stand-alone costs, inefficient by-pass opportunities may emerge.

In contrast, for volume customers, the focus in assessing prices is generally whether they are at least meeting the incremental costs of service provision. However, there will also be some larger commercial and industrial customers where the stand-alone costs may be exceeded.

*Volume customers*

In response to requirements in the Draft Decision, Allgas provided a more comprehensive analysis of cost reflectivity. This analysis showed that, for small volume customers (typically domestic customers), cost reflectivity remained a problem in 2005-06. Allgas' analysis showed that 20 per cent of these customers did not cover their short run incremental costs and a further 40 per cent did not meet their long run incremental costs.

The issue of cost reflectivity has persisted since the current access arrangement was approved in 2001. At that time, the Authority approved a provision that allowed Allgas to raise prices to domestic customers by a flat amount (\$7 per year) where this was greater than the general (CPI based) side constraint. This provision was intended to allow prices to rise more rapidly for small volume customers so that prices would become cost reflective by the end of the current regulatory period. Unfortunately, this provision was not used by Allgas and, not surprisingly, the problem of cost reflectivity remains for these customers. In fact, the problem appears to have deteriorated over the access period rather than improving.

Apart from raising prices, Allgas could have addressed the cost reflectivity of domestic customers by encouraging greater gas use by existing customers, in particular by those who currently use gas for cooking only. While average consumption per domestic customer has increased over the current regulatory period, this increase was not sufficient to have any real impact on the cost reflectivity of the group. In 2005-06, average consumption for those customers in the lowest tariff band in 2005-06 was still only marginally higher than Allgas' short run break even point of 4.1 GJ.

While Allgas has taken some steps to ensure that new customers will consume sufficient gas to ensure that cost reflectivity is achieved, insufficient emphasis has been placed on existing customers that do not consume enough gas to be cost reflective at current tariff levels.

In considering the issue of cost reflectivity, the Authority must ensure that the reference tariffs proposed by Allgas comply with the requirements of the Code. In particular, the revenue requirement must be allocated to customer groups such that direct costs (Section 8.38(a)) and the shared costs for each customer group (Section 8.38(b)) are met. Furthermore, the Code requires that individual customers contribute sufficient revenue to offset the cost of providing the reference service to that customer (Section 8.42).

The Code also requires the Authority to consider the legitimate commercial interests of Allgas. Therefore, any reasonable undertaking by Allgas to address the issue of cost reflectivity that may take time to implement is a consideration that must be weighed against the immediate need to address cost reflectivity.

There are a range of means by which the Authority could require Allgas to address the outstanding issues of cost reflectivity. These include:

- reducing the asset base to bring prices into line with asset values. This could be done by removing the value of redundant capital associated with non-cost reflective customers from the capital base. Any capital expenditure directed towards these customers could also be regarded as not prudent, consistent with the requirements of Code. This would reduce the return to Allgas of assets dedicated to non-cost reflective customers and thereby improve cost reflectivity at existing tariff rates;
- imposing minimum price increases for customers in non-cost reflective tariff bands; or
- providing Allgas with sufficient flexibility to adjust prices over the next regulatory period to achieve cost reflectivity.

Invoking the capital redundancy provisions contained in Allgas' current access arrangement would be effective in addressing the issue of cost reflectivity. However, while such action may be warranted in terms of the Code's requirements for all customers to be cost reflective, this could significantly affect future commercial decisions made by Allgas and, as such, capital redundancy is considered to be an instrument of last resort.

While cost reflectivity could be addressed through price mechanisms alone, greater use of gas by small consumers, which is at the heart of the problem, may be discouraged by higher prices. Furthermore, the specification of minimum tariffs would require the Authority to become involved in tariff approval at a level below the weighted average price path for volume customers. In principle, the Authority is of the view that service providers are best placed to determine tariffs and tariff bands at the individual customer level, as discussed in the next section. In addition, minimum price increases could result in some volume customers, who are already cost reflective, paying too much.

The Authority would prefer that Allgas decide, and take the necessary steps to address the outstanding issues of cost reflectivity relating to small volume customers. This was the Authority's intent in approving the access arrangement in 2001 but, unfortunately, Allgas did not make best use of the opportunity provided. Nevertheless, the Authority will persist with this preferred approach. However, the significant and ongoing problem of cost reflectivity for small volume customers will have to be addressed by Allgas during this next regulatory period. If the situation has not been resolved by the end of the next regulatory period (by which time Allgas will have had 10 years to address the problem), Allgas should be aware that there is the very real possibility that there will be an appropriate reduction made in the value of the regulatory asset base.

In relation to commercial and industrial customers, the Authority has examined the data supplied by Allgas. Overall, the Authority considers that these customers are currently paying

between their incremental and stand-alone costs of supply. The Authority accepts that, were individual consumers to be charged at higher than stand-alone costs, there would be a risk of bypass or substitution to other fuel sources and that this risk should be sufficient to discourage such pricing by Allgas.

The Authority therefore accepts the overall side constraint proposed by Allgas for volume customers of CPI+3% for individual customers. However, with respect to small volume customers, the Authority does not intend to indicate an additional side constraint as it did in 2001 (of \$7 per year). Rather, in approving annual prices, the Authority will consider any request by Allgas for price increases of more than CPI+3% to individual customers, or group of customers, where this will assist prices to those customer(s) to become more cost reflective.

### **Amendment 15.3**

**In order for Allgas' access arrangement to be approved, Allgas must revise its side constraint to be a maximum of CPI+3% or any higher amount approved by the Authority where this increase can be demonstrated to result in tariffs becoming more cost reflective.**

#### Demand customers

The Authority considers that the stand-alone costs for demand customers should be based on an efficient hypothetical new entrant. This principle is not consistent with Allgas' pure stand-alone cost analysis, which takes all existing costs as given and does not recognise the benefits of economies of scale.

Allgas' alternative 'joint' stand-alone cost test, on the other hand, recognises the benefits that exist in serving demand customers who are grouped together. The lower stand-alone costs under the joint stand-alone costs test therefore reflects economies of scale and represents a more efficient benchmark for evaluating Allgas' performance.

The calculation of the joint stand-alone costs was based on an engineering assessment conducted by Allgas. The Authority is satisfied that the revenues earned by Allgas in 2005-06 from demand customers do not exceeded the (joint) stand-alone costs.

However, if revenues rise as Allgas predicts, then total revenues from demand customers may, by the end of the next period, exceed (joint) stand-alone costs (at least at the lower end of Allgas' suggested range). This issue may have to be looked at more closely at the next regulatory reset. However, the price path set by the Authority for demand customers, and the risk of by-pass, will mitigate this possibility to some degree.

## **15.6 Tariff structure**

Within customer groups, tariffs can be structured to recover the required revenue in a number of different ways. In general, reference tariffs relate to the number of end users (connections) and the consumption patterns of those end users (volume). Some proportion of the reference tariff is recovered as a flat fee, while the remainder is recovered through charges that vary depending on the volume of gas consumed by the end user or the amount of capacity reserved.

In addition, reference tariffs may vary by the location of the customer, with those in different parts of the network charged on the basis of the costs of supplying that part of the network (zones).

Issues that arise in assessing tariff structure include how reflective the proposed structure is of costs and the incentives the structure may create in terms of encouraging efficient use of the network.

### *Allgas' proposal*

The reference tariffs proposed by Allgas incorporate the following key features:

- fixed charges cover a proportion of the service and metering costs as well as a percentage of the administration servicing costs;
- nominated MHQ or demand charges reflect the average costs of shared network provision or contracted capacity;
- \$/GJ or \$/GJ of MDQ charges are used for the recovery of other costs; and
- \$/GJ or \$/GJ of MDQ charges are declining block tariffs to provide incentives to improve network utilisation.

The tariffs have been designed to ensure that there are no major pricing discontinuities at the boundary between tariffs. Such discontinuities can provide perverse incentives for users to change reference services.

Allgas has proposed reference tariffs as outlined in the following tables and are unchanged from those presented in the Draft Decision.

**Table 15.7: Allgas proposed reference tariffs – small customers (inclusive of GST)**

<i>Small customer service</i>	<i>Measure</i>	<i>Rate</i>
Base charge	\$/day	0.245
Up to 0.0255GJ of gas delivered per day	\$/GJ	14.48
Next 1.6745GJ of gas delivered per day	\$/GJ	8.37
Next 8.3GJ of gas delivered per day	\$/GJ	6.24
All gas delivered over 10GJ per day	\$/GJ	3.95

Prices for customers in the small customer group (Table 15.7) were based on averaging and were the same regardless of location.

For end users in its large customer group, Allgas has established pricing zones. These zones include:

- Brisbane - three zones based on distance from the transmission pipeline;
- South Coast - three zones based on distance from the transmission pipeline.
- Toowoomba - two zones based on distance from the transmission pipeline; and
- Oakey - two zones.

Table 15.8 provides the proposed demand customer prices for the 10 regions in the Allgas network.

**Table 15.8: Allgas proposed reference tariffs – large customers (inclusive of GST)**

Charge	Measure	Brisbane			Gold Coast			Toowoomba		Oakey	
		Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Demand charge	\$/GJ of MHQ/day	1.49	2.26	1.76	1.31	2.25	2.33	1.32	2.71	1.13	1.70
MDQ charges											
MDQ =<50GJ	\$/day	67.84	97.58	111.96	138.1	138.03	144.81	52.09	68.01	54.96	122.14
50GJ<MDQ<125GJ	\$/day	67.84 + 0.79/GJ of MDQ	97.58 + 1.48/GJ of MDQ	111.96 + 2.30/GJ of MDQ	138.1 + 2.61/GJ of MDQ	138.03 + 2.74/GJ of MDQ	144.81 + 2.89/GJ of MDQ	52.09 + 0.37/GJ of MDQ	68.01 + 0.77/GJ of MDQ	54.96 + 0.48/GJ of MDQ	122.14 + 2.37/GJ of MDQ
125GJ<MDQ<275GJ	\$/day	127.09 + 0.58/GJ of MDQ	208.58 + 1.24/GJ of MDQ	284.46 + 1.76/GJ of MDQ	333.85 + 2.23/GJ of MDQ	343.53 + 2.35/GJ of MDQ	361.56 + 2.47/GJ of MDQ	79.84 + 0.30/GJ of MDQ	125.76 + 0.62/GJ of MDQ	90.96 + 0.40/GJ of MDQ	299.89 + 1.91/GJ of MDQ
275GJ<MDQ<525GJ	\$/day	214.09 + 0.25/GJ of MDQ	394.58 + 0.58/GJ of MDQ	548.46 + 0.94/GJ of MDQ	668.35 + 1.87/GJ of MDQ	696.03 + 2.02/GJ of MDQ	732.06 + 2.12/GJ of MDQ	124.84 + 0.25/GJ of MDQ	218.76 + 0.41/GJ of MDQ	150.96 + 0.27/GJ of MDQ	586.39 + 1.17/GJ of MDQ
MDQ>525GJ	\$/day	276.59 + 0.20/GJ of MDQ	539.58 + 0.22/GJ of MDQ	783.46 + 0.26/GJ of MDQ	1135.85 + 1.63/GJ of MDQ	1201.03 + 1.75/GJ of MDQ	1262.06 + 1.84/GJ of MDQ	187.34 + 0.23/GJ of MDQ	321.26 + 0.24/GJ of MDQ	218.46 + 0.23/GJ of MDQ	\$878.89 + 0.50/GJ of MDQ

### Prudent discounts

At the 2001 review of Allgas' access arrangement, the Authority approved prudent discounts for four of Allgas' customers.

Since the Draft Decision, Allgas has proposed that these prudent discounts be retained and rolled over to the next regulatory period.

### *Other jurisdictions*

IPART (2005) investigated the cost allocation approach of AGLGN to various tariffs. It investigated how specific costs would be best allocated. It also investigated the overall structure of prices, for example, rejecting AGLGN proposal to reduce the number of zonal tariffs from seven to five. IPART argued that greater cost reflectivity is achieved with more zones and believed that retaining pricing on seven zone remained technical feasible and commercially reasonable.

ACCC (2002) assessed GasNet's allocation of costs to 19 tariff zones. The ACCC investigated specific matters, such as the number of zones that would be desirable and whether specific costs would be best allocated directly to a particular group of users or allocated more generally.

IPART (2005) accepted AGLGN's proposed prudent discounts for two customers. IPART considered that alternative energy sources posed a real threat of by-pass for these customers as required by the Code. IPART also considered that the revenue received by AGLGN from the two customers was above the marginal cost of providing the service and hence, the inclusion of revenue from these users lowers the costs for other users of the network as required by the Code.

### *Submissions from stakeholders*

Energex Retail supported the zonal tariff structures provided by Allgas.

### *QCA position*

The Authority considers that the service being provided by gas distribution network owners relates to transportation of a product, that is, natural gas. The costs associated with providing this service generally do not vary significantly with throughput. Consequently, the service provider would generally have a strong incentive to sell capacity in the network, irrespective of the actual amount of gas transported.

In this regard, the Authority sees merit in the tariff structure for the demand (large) customer group, as charges relate to the amount of capacity reserved by the user of the network rather than gas volume transported.

Similarly, given that a high proportion of the costs of operating the network are fixed, the Authority is of the view that there is a strong argument for the amount of revenue recovered by way of fixed charges to be relatively high.

The Authority notes that Allgas has proposed a declining block tariff structure, with costs per unit sold declining as consumption increases. The Authority supports this approach as encouraging the development of the market for reference services, which should ultimately reduce costs to the benefit of Allgas and current and prospective users.

Overall, the Authority considers that tariff structures are best left to the service provider to determine. Accordingly, the Authority proposes to allow Allgas to resubmit its proposed reference tariff schedules in light of its required amendments. However, the Authority is also cognisant of the requirements of the Code in respect of achieving reference tariffs that are cost reflective for all users to the maximum extent that is commercially and technically reasonable. The Authority therefore encourages Allgas to take account of the issues above when reconsidering the setting of reference tariffs in light of the amendments required throughout this Final Decision.

#### Prudent discounts

Section 8.43 of the Code provides that a regulator may, with effect from the commencement of an access arrangement period, permit a gas distributor to offer a prudent discount to an end user of the network. A prudent discount can arise where a shortfall in revenue that results from one user not paying the full reference tariff is recovered from other users of the reference services. The criteria for assessing whether the discount is prudent requires that the discount results in the retention of the end user, who would otherwise leave the network, and that this results in lower reference tariffs for remaining end users compared to the reference tariff that would need to be charged if the user left the network. Put another way, a prudent discount may be approved by the regulator where there is a threat of bypass and as long as the end user is making some contribution to the fixed costs of the network.

The Authority has reassessed the prudent discounts sought by Allgas. Based on the data supplied by Allgas, the revenue to be recovered from each customer is greater than the average incremental costs of supplying a demand customer. Therefore, the discounted charges are likely to include some contribution to the shared network. The Authority has accordingly decided to allow the discounts to be recovered from other customers. Given the small sums involved, the Authority does not consider it necessary to stipulate from which groups of customers the discounts should be recovered.

#### **Amendment 15.4**

**In order for Allgas' access arrangement to be approved, Allgas must revise its tariff schedules such that they are consistent with the revenue requirement amendments of this Final Decision.**

## **LIST OF SUBMISSIONS**

### ***Draft Decision***

Allgas

Energy Users Association of Australia

TRUenergy

Queensland Government

### ***2006 Revised Access Arrangement***

Energex Retail

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