QUEENSLAND COMPETITION AUTHORITY

Access Arrangements for Queensland Gas Distribution Networks

Issues Paper

November 2000

SUBMISSIONS

The Queensland Competition Authority (the Authority) considers public involvement to be an important element of its decision making processes. It therefore invites submissions from interested parties on any issues raised by, or relevant to, the draft access arrangements and access arrangement information lodged by Allgas and Envestra in relation to their gas distribution networks. These draft access arrangements and access arrangement information are available on the Authority's website or by telephoning the Authority on 07-3222 0555.

To facilitate the publication of submissions on the QCA's website, it is preferred if submissions could be made electronically by disk or email. Written submissions should be sent to the address below. While the Authority does not require submissions in any particular format, it would be appreciated if two printed copies are provided together with an electronic version on disk (Microsoft Word format) or by email. However, if this is not possible, submissions can be made in writing. **Submissions, comments or inquiries regarding this paper should be directed to:**

Queensland Competition Authority
GPO Box 2257
Brisbane QLD 4001
Attention: EJ Hall
Telephone: (07) 3222 0555
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Email: gas.submissions@qca.org.au

The **closing date** for submissions is **22 December 2000**.

Confidentiality

In the interests of transparency and to promote informed discussion, the Authority would prefer submissions to be made publicly available wherever this is reasonable. However, if a person making a submission does not want that submission to be public, that person should claim confidentiality in respect of the document (or any part of the document). Claims for confidentiality should be clearly noted on the front page of the submission and the relevant sections of the submission should be marked as confidential, so that the remainder of the document can be made publicly available. Again, it would also be appreciated if each version (that is, the complete version and another excising confidential information) could be provided electronically (whether or not with a printed copy). Where it is unclear why a submission has been marked 'confidential', the status of the submission will be discussed with the person making the submission.

While the Authority will endeavour to identify and protect material claimed as confidential as well as exempt documents (within the meaning of the *Freedom of Information (FOI) Act 1989*), it cannot guarantee that submissions will not be made publicly available. As stated in s187 of the *Queensland Competition Authority Act 1997*, the Authority must take all reasonable steps to ensure the information is not disclosed without the person's consent, provided the Authority is satisfied that the person's belief is justified and that the disclosure of the information would not be in the public interest.

Public access to submissions

Subject to the above, submissions will normally be made available for public inspection at the Brisbane office of the Authority (see below), or on its website at www.qca.org.au.

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ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AGA	Australian Gas Association
AGL	Australian Gas Light Company
ASX	Australian Stock Exchange
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
Code	National Third Party Access Code for Natural Gas Pipeline Systems
CPI	Consumer Price Index
CPI-X	Consumer Price Index minus a productivity improvement factor
DAC	Depreciated Actual Cost
DCF	Discounted Cash Flow
DORC	Depreciated Optimised Replacement Cost
DUOS	Distribution Use of System
EV	Economic Value
GJ	Gigajoule (10^9 joules)
GST	Goods and Services Tax
ICB	Initial Capital Base
IPART	Independent Pricing and Regulatory Tribunal, New South Wales
IRR	Internal Rate of Return
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MDQ	Maximum Daily Quantity
MHQ	Maximum Hourly Quantity
MJ	Megajoule (10^6 joules)
NCP	National Competition Policy
NPV	Net Present Value
NRV	Net Realisable Value
O&M	Operating and Maintenance
ODV	Optimised Deprival Value
OffGAR	Office of Gas Access Regulation, Western Australia
ORC	Optimised Replacement Cost
ORG	Office of the Regulator General, Victoria
OTTER	Office of the Tasmanian Electricity Regulator
PJ	Petajoule (10^{15} joules or one million gigajoules)
QCA	Queensland Competition Authority (also known as the Authority)
SAIPAR	South Australian Independent Pricing and Access Regulator
SUG	Systems Use Gas
TJ	Terajoules (10^{12} joules or 1000 gigajoules)
UAG	Unaccounted for gas
WACC	Weighted Average Cost of Capital

1. INTRODUCTION

1.1 QCA responsibilities

The Queensland Competition Authority (the QCA or the Authority) is a statutory body established under the *Queensland Competition Authority Act 1997*. The Authority has certain responsibilities and functions with respect to National Competition Policy (NCP), which broadly include:

- subject to reference or declaration by the Ministers (the Premier and the Treasurer), undertaking prices oversight of monopoly or near monopoly Government business activities;
- receiving and investigating competitive neutrality complaints against significant Government and local government business activities;
- accrediting significant Government and local government business activities as complying with the principle of competitive neutrality;
- overseeing and arbitrating third party access to infrastructure; and
- undertaking such other activities relating to NCP as the Ministers may direct.

With respect to natural gas, the Authority has particular responsibilities as outlined in the *Gas Pipelines Access (Queensland) Act 1998* (the Act). The Act encompasses and gives effect to the National Third Party Access Code for Natural Gas Pipeline Systems (the Code). The Act provides for the progressive introduction of contestability for gas consumers in Queensland. Consumers of more than 100 TJ of gas per annum will be able to choose their supplier from 1 July 2001, with all other consumers becoming contestable from 1 September 2001.

The Act and Code provide for the Authority to approve access arrangements for four 'covered' gas distribution networks in Queensland, owned by Allgas Energy Limited, Envestra Limited, and Dalby and Roma Town Councils. Access to gas transmission pipelines is regulated by the Australian Competition and Consumer Commission (ACCC). Access arrangements stipulate basic conditions under which third parties (generally other retailers) can utilise the transmission and distribution networks in order to compete with incumbent retailers for the business of contestable customers.

An access arrangement describes the policies as well as the terms and conditions upon which third party access to a covered pipeline will be granted, and, under the Code, must meet a number of minimum requirements. These include:

- non pricing issues, namely:
  - a Services Policy, which describes the services a provider will make available to users/prospective users;
  - Terms and Conditions, outlining reasonable terms and conditions upon which each service is to be provided;
  - a Capacity Management Policy, incorporating a statement of whether the pipeline is to be operated on a contract carriage or a market carriage basis;
  - 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;

- a Queuing Policy, which determines the priority prospective users have in gaining access to specific capacity;

- 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 to the Code and how this will affect reference tariffs;

- 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 describes the basis upon which tariffs are determined or are to change. This section will involve detail in respect of, among other things, determining an initial capital base, a rate of return, depreciation, capital expenditure, revenue and the allocation of costs.

1.2 Process for approval of access arrangements

In reaching a final decision on a proposed access arrangement, the Code requires a number of procedures to be followed. Broadly speaking, these entail:

- submission by the service provider of both a proposed access arrangement and accompanying access arrangement information to the QCA. 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 in regard to compliance with the Code;

- publication of a notice requesting submissions on the proposed access arrangement;

- following consideration of submissions received on the proposed access arrangement, the release of a draft decision by the QCA, along with a further call for submissions; and

- after due consideration has been given to submissions on the draft decision, the release of a final decision by the QCA to either approve the access arrangement, or to approve it subject to revisions.

The Act was passed by the Queensland Parliament in May 1998 and was proclaimed on 19 May 2000. Under the provisions of the Code, this meant owners of gas distribution networks had until 17 August 2000 (90 days) to submit access arrangements and access arrangement information to the Authority for approval. The Authority then has a period of six months to consider the access arrangements and issue a draft and a final decision.

In response to requests from network owners, the Authority decided on 15 August 2000 to extend the 90 day period by a further two months. The revised date for submissions was therefore set at 17 October 2000. Access arrangements were submitted on this date for the Allgas Energy Limited and Envestra Limited systems, and the Authority is now releasing these along with this issues paper, to facilitate submissions from interested parties. Access arrangements for Dalby and Roma Town Councils have not yet been lodged pending consideration of revocation of coverage in the case of Dalby and ownership issues with respect to Roma.

This paper is intended to provide a summary of key issues, but should not be taken as a substitute for reading the actual access arrangements and access arrangement information, which can be found at the Authority's website at www.qca.org.au. Copies may also be obtained by telephoning the Authority on 07-3222 0555.

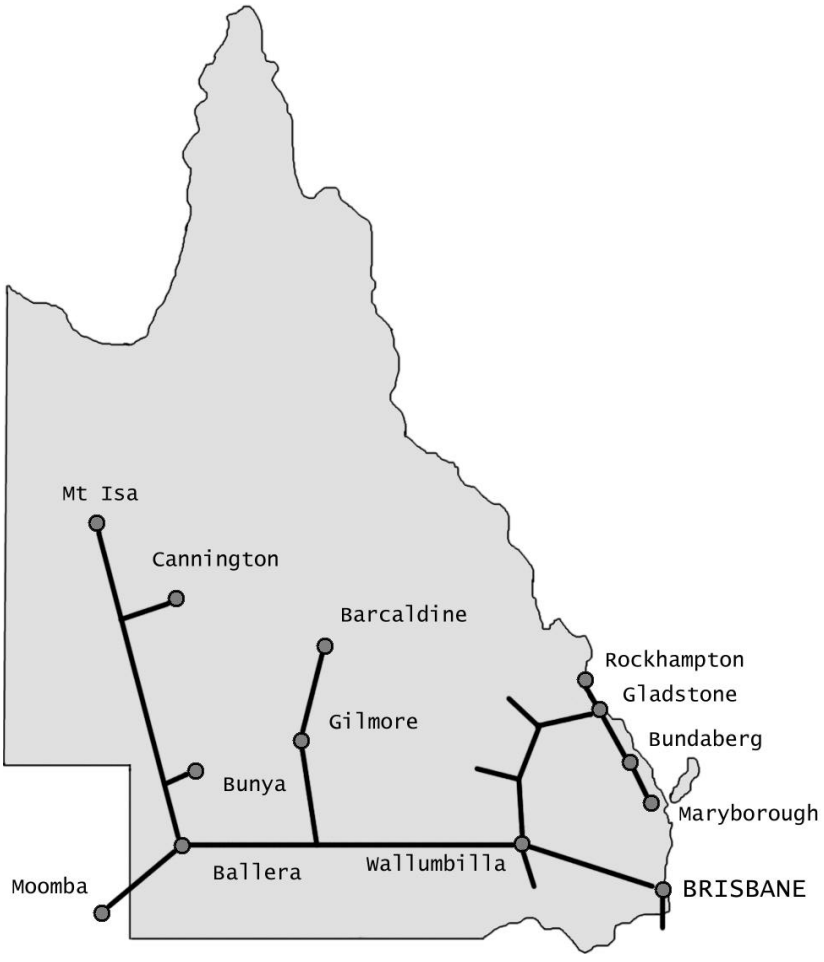
2. NATURAL GAS PIPELINES IN QUEENSLAND

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. Major transmission pipelines (see Figure 2.1) include:

- the Wallumbilla to Brisbane pipeline, owned by the Australian Pipeline Trust;
- the Ballera to Wallumbilla pipeline, owned by Epic Energy Pty Ltd;
- the Wallumbilla to Rockhampton pipeline system, owned by Duke Energy International; and
- the Ballera to Mt Isa pipeline, majority owned by the Australian Pipeline Trust.

Access to these transmission pipelines is regulated by the ACCC.

Figure 2.1: Queensland gas transmission pipelines



Source: AGA website

Relative to other jurisdictions, Queensland's overall gas market is relatively small, representing less than six per cent of total energy consumed in the State (see Table 2.1).

Table 2.1: Gas as a share of total energy consumed, by jurisdiction, 1997-98 (%)

	NSW	Vic	Qld	WA	SA	NT	Total
Manufacturing	21.0	39.8	13.8	69.8	38.4	0.5	29.7
Commercial	23.1	38.0	2.9	22.8	26.4	5.3	23.3
Residential	15.3	55.1	2.9	25.9	24.9	0.0	29.8
All other	2.4	5.2	1.7	41.3	33.9	42.3	11.3
TOTAL	**9.4**	**18.9**	**5.2**	**46.9**	**33.8**	**26.8**	**17.9**

Source: AGA 2000

In terms of natural gas distribution networks, Queensland has four systems:

- the Envestra system, including Gladstone, Ipswich, North Brisbane and Rockhampton, owned by Envestra Limited (Envestra);
- the Allgas system, including the Gold Coast, Oakey, South Brisbane and Toowoomba, owned by Allgas Energy Limited (Allgas);
- the Dalby Town Council system, located in the town of Dalby; and
- the Roma Town Council system, located in the town of Roma.

Sales of gas to end users in Queensland are predominantly through direct contracting. Of the total of 52 PJ of gas consumed in Queensland in 1997-98, only 11.4 PJ, or around 22 per cent, was delivered through utility sales via distribution networks. This volume rose to 14 PJ in 1998-99.

Of gas delivered via distribution systems, most relates to those pipeline systems owned by Envestra and Allgas. Table 2.2 indicates that while Envestra has more natural gas customers, it sells less than half the volume of gas of Allgas.

Table 2.2: Details of gas distribution networks in Queensland, 1998-99

Owner	Number of customers	Length of mains (km)	Total gas sold (PJ)
Envestra	70,161	2,026	4.3
Allgas	58,979	1,900	9.2
Dalby Town Council	2,400	87	0.14
Roma Town Council	305	21	0.02

Source: Distribution network owners

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 Surfers Paradise and Coolangatta); and
- the Tweed Heads region in north east New South Wales.

The network comprises approximately 1,900 kilometres of low, medium and high pressure mains. About 68 per cent of the network is located in Brisbane, 19 per cent in the Western region and the remaining 13 per cent on the South Coast and Tweed Heads. As at 30 June 2000, Allgas served a total of 58,870 small customers (less than 10 TJ of gas per annum) and 109 large customers (10 TJ or more of gas per annum).

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 2,026 kilometres of low, medium, high and transmission pressure mains. Assets used to service the Brisbane region comprise 89 per cent of the network with the balance of 11 per cent attributable to the Northern region. As at 30 June 2000, Envestra served 70,105 small customers (less than 10 TJ of gas per annum) and 56 large customers (10 TJ or more per annum).

PART A: NON PRICING ISSUES

3. SERVICES POLICY

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 access services may be offered.

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

3.1 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:
  - one or more services that are likely to be sought by a significant part of the market; and
  - any service or services which in the QCA'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.

3.2 Issues in determining the services policy

There are a number of elements of a services policy that potentially may be varied between services, including:

- continuity of supply, for example, firm versus interruptible;
- duration of supply period, for example, extended versus spot service, long term versus short term supply;
- volume of supply, for example, capacity based or throughput based;
- distance, for example, use of pricing zones to approximate network costs; and
- direction, for example, backhaul services.

The determination of a services policy will depend in part on the nature of the market being served and the needs of consumers.

Additional services that may be offered in the course of business for a gas distribution network (such as special meter reading, disconnection and reconnection) could be defined as reference services in circumstances where the relevant regulator deems they should be included in the services policy. Issues that may affect this decision include the need for the price for such services to be set by a regulator or, in other words, the extent to which monopoly power may be exercised in the setting of such prices.

Summary of access arrangement proposals

Allgas

Allgas has provided for three network services, namely:

- reference services;
- negotiated services; and
- ancillary services.

The access arrangement relates only to reference services, which are further defined as:

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

Broadly, both these services include forward haulage of gas, installation and reading of meters, connection, odorisation and pressure regulation.

Services that involve, for example, delivery of gas at a higher pressure would be negotiated services, with price subject to agreement between the relevant parties.

Ancillary services, including special meter reading, disconnection and reconnection, are not included as reference services (that is, the price for these services is not proposed to be approved by the QCA and revenue from these services does not form part of Allgas' regulated revenue).

Envestra

Envestra has proposed the following network services:

- two haulage reference services; and
- one utility reference service.

Haulage reference services are further defined as:

- a demand haulage service, which relates to situations where the annual quantity of gas delivered is equal to or greater than 10 TJ. The contract period is a minimum of one year; and
- a volume haulage service, for any delivery point that is not a demand delivery point.

These services include odorisation, provision and maintenance of metering equipment, provision of system use gas and meter reading.

The utility reference service is a special meter reading service. A reference tariff is proposed for this service, that is, the price is to be approved by the QCA and revenue from this service is to be included in total regulated revenue.

No provision has been made for negotiated services.

No provision has been made for disconnection or reconnection charges.

Other jurisdictions

The ACCC (2000b) approved an access arrangement for the Central West transmission pipeline which included only one service, charged on the basis of throughput. Negotiated services could also be provided where the requirements of the consumers differed from this reference service. The absence of a two part tariff or a variety of reference services to meet the needs of the market was accepted on the basis that it was the first access arrangement period and there was likely to be significant excess capacity.

IPART (2000a) required AGL to offer a range of reference services for its New South Wales distribution systems, including negotiated services, a service based on throughput, a service based on capacity reserved, a multiple delivery point service, a summer tranche service, a service allowing for short term capacity, backhaul services, and a service for the partial use of a local network.

AlintaGas proposed four basic reference services in its access arrangement for the Western Australian distribution systems, including in relation to high volume long term contracts, low volume long term contracts, and low volume one year contracts with various different types of metering services. OffGAR (2000a) required amendments to the AlintaGas access arrangement, including that the contractual requirements be made more flexible rather than relating to specified periods for example, one year, or two to five years. OffGAR also required that gas quality be specified in the services policy.

Envestra proposed three reference services with respect to haulage for its South Australian distribution network: domestic haulage, commercial haulage and demand haulage. Utility reference services, including special meter reading, disconnection and reconnection were also provided for. SAIPAR (2000a) required that an additional service be provided relating to short term services for small and medium customers.

The Authority seeks comment on the appropriateness of the services policy outlined by the gas distribution network owners, including whether the proposed reference services meet the principles as outlined in section 3.2 of the Code.

The Authority also seeks comment on whether ancillary or utility services (such as special meter reading, disconnection and reconnection) should be defined as reference services.

4. TERMS AND CONDITIONS

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 buyer.

4.1 Code requirements

The Code (section 3.6) requires 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 QCA's opinion, be reasonable.

4.2 Issues in determining terms and conditions

The Code requires the service provider to state what the terms and conditions will be in the access arrangement, which constitutes a basic contract for a specified reference service. However, it is not sufficient for these to be stated in advance. Advance notice of terms and conditions is only useful if the user has an alternative to using that service. Where there is a monopoly supplier of a good or service, the user is little better off knowing in advance that the terms and conditions of service are unfair. On the other hand, the service provider is entitled to reasonable protection of the investment in infrastructure. For these reasons, the regulator needs to be involved, to balance the interests of both providers and users of the service.

The service provider may have various incentives to shift commercial risk to the user through the terms of the contract. By doing so, a service provider whose total revenue is regulated may improve the risk/return trade off faced by that business. In the case of a vertically integrated service provider, the terms and conditions offered to other retailers could act to discourage entry into the market.

In commercial negotiations, it is important to consider the reasonableness of the terms and conditions when viewed as a whole, rather than that of each individual clause. For example, a binding condition on one of the parties may be reasonable or unreasonable, depending on the events that flow from a breach of that condition. A short time allowance for payment, even for an amount that may be subject to dispute, may be reasonable if a breach of this time limit triggers a process to recover the amount. However, it would be unreasonable if the effect were immediate termination of the agreement.

Summary of access arrangement proposals

The terms and conditions associated with the access arrangements are voluminous. The relevance of particular elements of terms and conditions will differ depending on the particular circumstances of each user. Stakeholders are therefore encouraged to read these in their original form. Several more general issues are raised below for the purposes of encouraging discussion. (References are to the relevant annexure to each access arrangement.)

- The distributors propose to provide themselves with substantial discretion regarding some matters that require judgement. For example, Envestra has proposed (section 21.4) that where a meter has not been read, it may estimate the quantity of gas delivered on whatever basis it considers reasonable. This may reduce the ability of the user to dispute Envestra's estimate.

- Both distributors require security from users, Allgas by means of a general statement (section 8.1) to the effect that it will reasonably determine the type and extent of security required, and Envestra by specifying a deposit equal to its estimate of the likely charges for the coming month (section 19.2). Envestra also requires the user to comply with its credit policy, including a requirement the user must have an acceptable credit rating (Chapter 4 of the access arrangement). The level of security required by the distributor will interact with the degree to which the user's creditworthiness is of interest to the distributor. The higher the level of security provided, the less would be the need for the distributor to consider creditworthiness. On the other hand, the security deposit has an interest cost, which would increase with the amount held as security.

- The grounds for suspension and termination of an access agreement need to be considered in conjunction with the level of security held by the distributors and the dispute resolution process. Both distributors propose the distributor may suspend services or terminate the agreement if payment is not made according to the agreement, Envestra immediately (sections 23.3 and 24.2), Allgas seven days after issue of a note of demand (section 8.5).

- Allgas proposes (section 16) a mandatory dispute resolution process, including the appointment of a mediator. However, the decision of the mediator is not binding unless both parties agree to be bound. Envestra (section 33) proposes a process that is mandatory if either party seeks arbitration, in which case both parties are bound by the arbitrator's decision, except for error. Dispute resolution processes may be cheaper and more timely than recourse to the legal system. At the same time, an access agreement is a legal document and parties ultimately may desire to seek an outcome through the courts. One issue is how much should the dispute resolution process be a voluntary alternative to the legal system.

- Should users withdraw significantly more gas from the network than expected, network pressure may not be sufficient to allow service delivery. The distributors have proposed to provide an incentive for users to forecast accurately, by increasing the amount of capacity a user reserves (and pays for) in response to a stated number of hourly or daily overruns. The potential cost to the distributor of overruns needs to be weighed against the proposed effects of the given number of overruns.

- The balance of risk between distributors and users (and the charges reflecting that balance) is reflected in the liability and indemnities accepted by each of the parties. An agreement that provides for substantial waivers of liability for either party should be reflected in the charges paid for the service. Envestra proposes to significantly reduce its liabilities, both expressly (section 25) and through wide indemnities by users (section 29). One issue here relates to whether this sharing of risks is appropriate.

Other jurisdictions

Other jurisdictions have adopted a detailed approach to terms and conditions. Regulators have often required substantial changes to be made to these terms and conditions, in particular regarding the amount of detail provided by the service provider (which needs to be sufficient to allow the regulator to determine the reasonableness of the terms and conditions).

The Authority seeks comment on whether the terms and conditions offered by the service providers are fair and reasonable.

5. CAPACITY MANAGEMENT POLICY

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.

5.1 Code requirements

The Code (section 3.7) requires that an access arrangement must include a capacity management policy, which is a statement that the covered pipeline is either a contract or a market carriage pipeline. Essentially, a contract carriage pipeline relies on capacity being contracted to particular users, while a market carriage pipeline relies on spot prices based on actual usage of services.

Under section 3.8 of the Code, the QCA cannot accept an access arrangement which states that the covered pipeline is a market carriage pipeline unless it has been notified by the Queensland Minister for Mines and Energy that the pipeline is permitted to be a market carriage pipeline. If a pipeline is a contract carriage pipeline, the access arrangement must contain a trading policy.

5.2 Issues in determining the capacity management policy

The QCA has not been notified by the Queensland Minister for Mines and Energy that any Queensland pipelines covered by the Code are permitted to be market carriage pipelines. Accordingly, all distribution networks are required to be contract carriage pipelines.

Summary of access arrangement proposals

Both Allgas and Envestra have proposed contract carriage pipelines.

Other jurisdictions

Service providers in most other jurisdictions proposed contract carriage pipelines, which were accepted by the relevant regulator. In Victoria, distribution service providers proposed a market carriage pipeline. The ORG (1998b) accepted this, noting the difference was not really relevant with regard to distribution pipelines, although it was important with regard to transmission pipelines.

The Authority seeks comment on any issue concerning the capacity management policies proposed by the service providers.

6. TRADING POLICY

A trading policy is an integral element of contract carriage systems, and enables 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.

6.1 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 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 (other transfers). Consent may be withheld only on reasonable commercial or technical grounds and may specify conditions under which 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 consent will or will not be given and any conditions attaching to that consent.

6.2 Issues in determining the trading policy

Generally, trading policies have raised few contentious issues. However, where there has been discussion on trading policies, it has generally centred on whether a proposed policy could be considered to be overly restrictive on users and therefore likely to increase the cost and reduce the frequency of capacity trading.

Summary of access arrangement proposals

The trading policies submitted by both Allgas and Envestra permit bare transfers without the service providers' 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 the service provider's consent. The service provider may only withhold consent on reasonable commercial and technical grounds.

The proposed trading policies also permit changes to delivery and receipt points with the prior written consent of the service provider and where the change is commercially and technically reasonable.

The trading policies also stipulate that administrative fees associated with investigating the technical and commercial feasibility of any application for transfer will be applied to either the transferee or transferor.

Other jurisdictions

With regard to bare transfers, service providers have generally permitted users to transfer or assign contracted capacity provided the transferee, prior to utilising this right, gives notification of the portion of contracted capacity subject to the bare transfer and of the nature of the transfer. However, there are some access arrangements which do not require the user to supply any information in relation to a transfer.

With regard to transfers other than bare transfers, service providers have generally proposed policies broadly consistent with the Code in that such transfers are permitted, but only to the extent that the transfer is commercially and technically reasonable.

While regulators have required amendments to a number of proposed trading policies in respect of transfers other than bare transfers, the amendments have generally been on marginal issues largely unique to the pipeline in question.

With regard to the changing of receipt and delivery points, generally access arrangements permit the user to alter these points where it is commercially and technically reasonable. However, some regulators have considered provisions relating to this issue as being overly restrictive, and accordingly, have required that the access arrangements be amended to relax some of the conditions and/or to clarify the conditions under which consent will or will not be given.

The Authority seeks comment on whether the proposed trading policies are generally in accordance with the Code provisions.

The Authority also seeks comment on whether any aspects of the trading policies are overly restrictive.

7. QUEUING POLICY

Queuing for a good or service is one means of rationing, where that good or service is scarce, with 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. Queuing therefore provides a mechanism by which the right of access to a pipeline is determined where capacity is fully or close to fully utilised.

7.1 Code requirements

The Code (section 3.12) requires that 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 (a queuing policy). Developable capacity is 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.

7.2 Issues in determining the queuing policy

The Code requires an access arrangement to contain a queuing policy in order to prevent favouritism by the service provider to any associated retailer, and to provide a mechanism by which disputes can be resolved between two competing users.

To be effective in serving these two purposes, a queuing policy must be both transparent and fair. A policy that provides a great deal of discretion to the service provider or that provides insufficient guidance as to how a dispute between users would be resolved, would not be adequate.

However, the application of a queuing policy is not cost free and there is a need to weigh the benefits of the policy against potential costs, such as increased administration costs to the service provider.

Summary of access arrangement proposals

Allgas

Allgas proposes a first come first served approach, with potential users needing to demonstrate their access to a supply of gas at the relevant time, before being admitted to the queue. Within a reasonable period of receiving a request, Allgas will advise the applicant of the number and aggregate capacity sought by applicants already in the queue and its estimate of when capacity may become available. When planning augmentation of the system, Allgas may revise the place in the queue of applicants, to maximise economic efficiency.

Envestra

Envestra proposes to process requests for access in the order in which they are received. Where there is insufficient spare capacity to satisfy all the next prospective user's requirements, Envestra will offer partial satisfaction to that user. Envestra may then investigate additions to capacity, together with reviewing the priority of potential users in the queue, in the interests of optimising design.

Other jurisdictions

In South Australia, Envestra proposed a first come first served approach, with augmentation of network where this was justified by the prospective return. This was accepted by the regulator (SAIPAR 2000a).

In Western Australia, AlintaGas proposed first come first served, with exceptions allowing variation in one party's legitimate business interests, to generate an economically efficient outcome or in dealing with a vexatious application. The regulator (OffGAR 2000a) required AlintaGas to remove reference to vexatious applications. It also required AlintaGas to include information regarding:

- providing revised information to a prospective user where there is a change in the expected timing of the requested capacity becoming available; and

- what would happen if spare capacity is not accepted by the applicant at the head of the queue.

Also in Western Australia, CMS Gas Transmission for its Parmelia pipeline proposed a first come first served approach, with exceptions in times of high demand allowing CMS to deal with access requests in a manner to maximise pipeline utilisation, to generate an economically efficient outcome. The regulator (OffGAR 1999) required CMS Gas Transmission to include information regarding:

- how priorities will be allocated in terms of requests for non-reference services;

- how priority between queues for 'extended' and 'interruptible' services will be treated; and

- the conditions under which queues will not indicate priority (that is, an economic efficiency clause).

In Victoria, Multinet, Westar and Stratus provided a general statement with little detail or rules and great discretion to the distributor. The regulator (ORG 1998b) required a first come first served approach. However, the ORG also recognised queuing was not likely to be significant issue, so preferred a simple approach.

The Authority seeks comment on whether the queuing policies proposed by the service providers are transparent and fair.

8. EXTENSIONS/EXPANSIONS POLICY

An access arrangement must include a policy setting out a method for determining whether an extension or expansion to the covered pipeline is or is not to be treated as part of the covered pipeline.

8.1 Code requirements

Section 3.16 of the Code requires an access arrangement to have an extensions/expansions policy which sets out a method for determining whether an extension or expansion of the pipeline will be treated as part of the covered pipeline. The policy must also specify how any extension or expansion will affect the reference tariff. In addition, if the service provider agrees to fund new facilities under certain conditions, the extensions/expansions policy must set out a description of the new facilities and the conditions on which the service provider will fund these 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 the Authority.

8.2 Issues in determining the extensions/expansions policy

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 not automatically 'covered'; and

- if included as part of the existing system, how the use of that extension or expansion should be priced.

Summary of access arrangement proposals

Allgas

The Allgas proposal draws a distinction between network extensions and network expansions (or augmentations). In the case of network extensions, Allgas has proposed that these will be automatically treated as part of the covered pipeline where the extensions are typically less than 10km in radial distance from any part of the existing covered network (a covered extension). However, where the extension is typically more than 10km radial distance from the existing network (an excluded extension), Allgas will have the option of treating the extension as either:

- part of the network; or

- an excluded network, in which case Allgas will notify the Authority of its exclusion and, together with the Authority, will establish appropriate arrangements for that extension.

The proposed extensions policy states that, where an extension meets the 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 s.8.16(b)(i), a capital contribution or surcharge for the incremental user/s may be charged by Allgas. Neither the capital contribution amount or 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 prevailing tariff prior to the extension and the user will pay the prevailing tariff plus the capital contribution or surcharge amount as determined by Allgas.

In the case of network expansions (or augmentations), the policy states that there will be no adjustment to the prevailing tariff arising from augmentation necessary to maintain the safety, integrity or contracted conditions of the network where such augmentation meets the test detailed in section 8.16 of the Code. However, where augmentation 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 prevailing tariff prior to the augmentation and the end user will pay the prevailing tariff plus the capital contribution or surcharge amount as determined by Allgas.

The access arrangement does not contemplate an augmentation necessary to maintain the safety, integrity or contracted conditions of the network as a whole, but which does not pass the economic feasibility test (section 8.16(b)(i)). There is also no reference to the intended approach where the extension or augmentation only partially satisfies the test detailed in section 8.16 of the Code.

Envestra

Envestra has proposed that all extensions and expansions will be automatically treated as part of the covered pipeline, except for extensions and expansions to provide service to customers where the anticipated consumption is in excess of 10TJ. In these cases, the access arrangement proposes that the extension/expansion will not be automatically covered by the access arrangement and Envestra will have the option of treating the extension/expansion as either:

- part of the network; or
- a stand-alone pipeline, in which case Envestra will provide notice to the Authority prior to the extension entering service. (It is unclear from the access arrangement what this notice would relate to or whether the QCA would have a role in regulating a stand-alone pipeline.) Envestra also maintains the option of including the extension as part of the network at any subsequent review.

The proposed extensions/expansions policy states that to the extent that an extension or expansion meets the economic feasibility test in section 8.16(b)(i), there will be no adjustment to the prevailing tariff.

The policy also states that, to the extent an extension or expansion has system wide benefits and that Envestra believes that these benefits justify the approval of a higher reference tariff, Envestra will seek the Authority's approval for a higher reference tariff for all network users.

In addition, the policy states that if an extension or expansion is necessary to maintain safety, integrity or contracted capacity but does not meet the economic feasibility test or provide system wide benefits, Envestra may seek revisions to the access arrangement.

The policy further states that Envestra will apply to the Authority to have a surcharge added to the reference tariff for incremental users in order to ensure that extensions/expansions which are not economically feasible at the reference tariff, become so.

The policy also explicitly states that Envestra is under no obligation to fund new facilities.

Other jurisdictions

Approaches adopted by regulators have generally approved polices which treat most extensions or expansions as part of the existing network, with reference tariffs to remain unchanged. In some cases, where the extension or expansion is considered significant, it may be excluded from the provisions of the access arrangement, usually with the prior consent of the regulator. In a number of access arrangements, surcharges are proposed to be charged in particular circumstances as permitted by the Code.

The Authority seeks comment on whether the extensions/expansions policy adequately addresses the requirements of the Code and is otherwise fair and reasonable.

9. REVIEW DATE

One of the purposes of an access arrangement is to provide both service providers and users with sufficient certainty regarding the terms and conditions under which they can make commercial decisions. Therefore, while a substantial period should be allowed for review of an access arrangement in order to facilitate greater certainty, this needs to be balanced against the risk associated with locking in the access arrangement for a long period, given that circumstances and markets will change over time.

9.1 Code requirements

The Code (section 3.17) requires that an access arrangement must include a date on or by which revisions to the access arrangement must be submitted and a date on which the revised access arrangement is intended to commence.

In approving these dates, the QCA can require that specific major events be defined that trigger an obligation on the service provider to submit revisions prior to the actual revisions submission date.

The Code (section 3.18) also states that an access arrangement period may be of any length. However, if the access arrangement period is more than five years, the QCA 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 proving incorrect.

9.2 Issues in determining the review date

Regulatory period

The confidence market participants can place in the market settings would generally be increased the longer the period of an access arrangement. However, other factors militate against very long regulatory periods. An access arrangement provides certainty regarding tariffs by allocating risk between service providers and users with regard to inflation, demand conditions and a range of other factors. This allocation itself exposes participants to risk, in that the assessment of risk underlying the reference tariff parameters is likely to change over time. Too long a period between reviews may lead to users being overcharged for services or the service itself proving to be unsustainable due to the divergence between original assumptions and actual outcomes. This problem would be reduced by a requirement to include mechanisms which may trigger a review during the course of the regulatory period.

Triggers for review

The Code provides that the QCA may require that specific events be defined that would trigger a review. There are two approaches to specifying such events.

First, specific events could be nominated, such as a change in demand by a specified amount above or below that originally forecast. This approach reduces the discretion of the service provider, in that no interpretation is required. On the other hand, unless a specific circumstance arises, no review could be undertaken.

The second approach would be to set out the classes of events that may trigger a review. For example, a trigger could be expressed as a significant change in one of the parameters used in establishing reference tariffs. This approach would allow a review to be triggered by any event with a material effect on supply or demand conditions for gas distribution.

Summary of access arrangement proposals

Allgas

Allgas has proposed a regulatory period of five years, with a review submission date nine months in advance of the end of the regulatory period. Trigger events include:

- variation in total gas demand of more than 10 per cent from that forecast (or 20 per cent for individual customers);
- variation in revenue of more than 10 per cent; and
- changes in costs which are beyond the control of Allgas, such as regulatory changes, gas balancing requirements, or changes in economic or environmental circumstances.

Envestra

Envestra proposes to submit revisions to its access arrangement on or before 1 October 2005, with the revised access arrangement to commence from 1 July 2006. The access arrangement provides for a review trigger should the development of a State or national policy for retail contestability require Envestra to modify its financial forecasts.

Other jurisdictions

Regulatory period

Generally, the regulatory periods in other jurisdictions have been of five years' duration. However, the ACCC decision (2000b) regarding the Central West Pipeline included a ten year regulatory period.

Review triggers

Most jurisdictions have adopted specific triggers for review. For example, IPART (1999b) required GSN to submit revisions to its access arrangement within one month of the development of a state or national policy for the introduction of retail contestability, and if there has been a change in taxation policy that has a major impact on reference tariffs.

However, in New South Wales, AGL proposed no triggers for review. This was accepted by the regulator (IPART 1999f) on the basis the time remaining in the initial regulatory period was too short to warrant interim reviews.

The Authority seeks comment on whether:

- **the access arrangement period suggested by the service providers is appropriate; and**
- **the list of specific major events that would trigger a review process is appropriate and defined adequately.**

PART B: PRICING ISSUES

10. GENERAL PRINCIPLES FOR REFERENCE TARIFFS

10.1 Objectives of pricing policy

Prices can be said to be efficient where the price of an additional unit will be equal to the additional cost incurred by the seller in producing that additional unit. That is, marginal revenue will equal marginal cost.

Where this condition exists, both sellers and buyers of the good or service are faced with appropriate price signals. The price received by a seller is at least sufficient to cover the costs of production. It also allows a buyer to compare the benefit of purchasing one additional unit of one good or service against that of purchasing another good or service. The demand at this price would provide signals to sellers regarding investment decisions, leading to an efficient allocation of resources across the economy.

In general, efficient prices are generated by an efficient market which, among other things, typically is characterised by a large number of buyers and sellers of the particular good or service. However, the gas distribution market in Queensland is characterised by one 'seller', that is, there is only one network in operation for any geographic region.

The rationale for having only one 'seller' in the gas distribution market relates to the high proportion of capital costs to total costs. Because of the large capital investment required to produce one unit of service, the marginal cost of production is relatively low and the average cost will be lower for each additional unit produced, across a very wide range. Put another way, the total costs of the gas network provider will not vary greatly across a wide range of production.

Industries with this characteristic are generally classified as being natural monopolies. Because average costs decline as the scale of production rises, one firm would tend to control production, as it is not economically efficient and usually not commercially viable to duplicate the network.

Because there is only one seller or supplier of gas distribution services, the monopolist has no incentive to price output at marginal cost, but at some point above this, depending on demand, designed to maximise the 'rent' from the monopoly position. For this reason, even in cases where a natural monopoly exists, monopolies are generally regulated.

The central problem for regulators of natural monopolies arises from the structure of costs. In such an industry, because of the high capital costs, pricing at marginal cost does not generate sufficient revenue to cover total costs. That is, the price charged for each additional unit of production will be below the average cost incurred by the seller in producing that level of output. In such a situation, there is no incentive for the monopolist to invest further. Existing capital would continue to be used, but would not be replaced. In some cases this might be appropriate, such as when over-investment has occurred. However, in many cases, this will not lead to an efficient outcome.

On the other hand, pricing at average cost, while it would provide an adequate return on investment to the monopolist, also would lead to an inefficient outcome. The buyer would not be faced with the marginal cost of production for each additional unit, distorting consumption choices. For a gas network, pricing on the basis of average cost may mean potential gas users that could cover the incremental costs they would impose on the network owner may not be able to be accommodated. This might also increase the cost per unit for all other users of the network, should those prospective users have been able to make a contribution to fixed costs.

The task for regulators is therefore to establish a pricing regime that:

- creates an environment where capacity is rationed efficiently and appropriate signals are provided to the network provider for augmentation of the system's capacity;
- allows the network provider to recover costs in a way that creates minimal distortion upon the production or consumption decisions of users of the network; and
- ensures that users face the full economic costs of their decisions.

In addition to these basic pricing issues, the vertical integration of one of the gas access providers (that is, it has a retail arm) introduces another set of problems. As well as monopolistic pricing, a vertically integrated owner of a gas distribution network has incentives to shift costs between business groups in a way to favour its own retailer. Such cost shifting would improve the competitive position of the 'in-house' retailer and possibly lead to improved results for the vertically integrated firm as a whole.

10.2 The link between prices and asset values

The rate of return represents the opportunity cost to investors for expected returns on forgone investment opportunities. It is the return expected by investors in capital markets for investments of a given level of risk and is determined by supply and demand for capital. In regulated industries which are not subject to market based determination of the cost of capital, the determination by the regulator of an appropriate rate of return on capital is central to generating prices which encourage efficient network usage in the short term and efficient investment in the medium to long term.

An inappropriate rate of return on gas distribution infrastructure may:

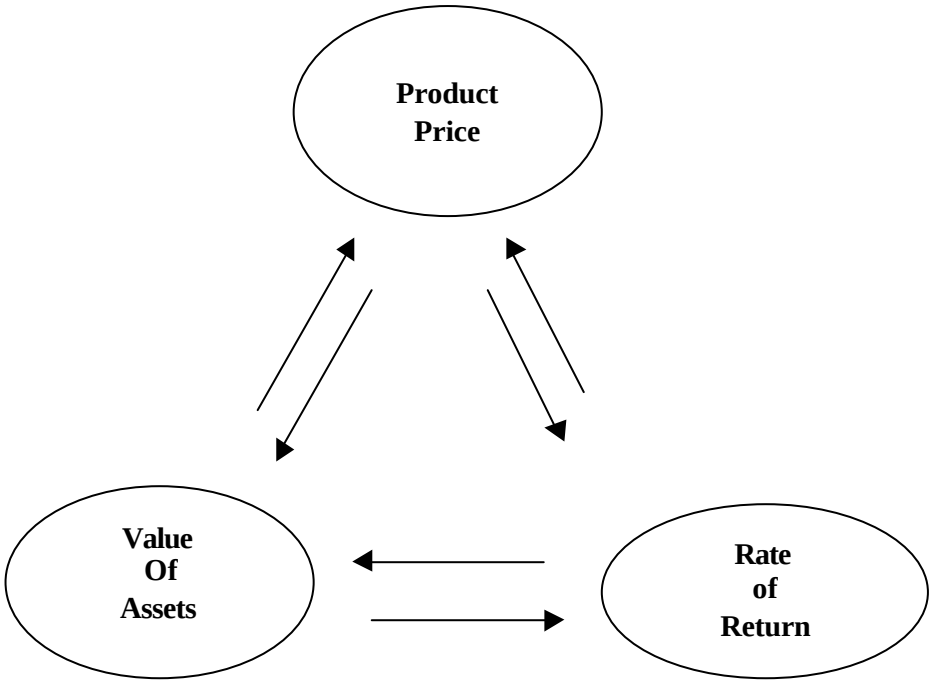
- result in over or under investment in the infrastructure. For example, if too high a rate of return is set, service providers would be encouraged to invest in the network to an excessive extent and users would be required to pay too much for using the network. However, if too low a rate of return is set, service providers would not be compensated adequately for their investment. While this would lower prices in the short term, service providers would be unlikely to undertake further investment (including replacement investment) in the network; or
- favour or penalise pipeline gas compared to other energy sources, such as electricity or bottled gas. This would lead to an inefficient allocation of resources across the economy.

The cost of capital therefore plays a critical role not only in compensating the network owner for its past investment, but also providing guidance as to the return on future investment in the network.

In a competitive environment, the market sets product prices. These prices determine the value of the assets used in production and, in turn, the return on investment. However, a monopolist has considerable discretion over the prices it sets. This can lead to a problem of circularity, if price setting is determined by the economic value of assets. That is, the economic value of assets would reflect (and thereby serve to legitimise) the prices charged by the monopolist.

Figure 10.1 illustrates this circularity problem and highlights the interdependence between product price, asset value and rate of return. Because the capital market effectively sets the rate of return, changes in price will affect the asset value.

Figure 10.1: Circularity of Prices, Rate of Return and Asset Value



In monopoly markets there is a need to calculate both the value of the assets and the rate of return, independently of the prices that are set through the process. There are a number of approaches to both valuing physical assets and quantifying the rate of return. Each of these approaches is likely to provide different outcomes and, consequently, different prices and incentives. These are discussed in a later section of this issues paper.

10.3 Code requirements

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, the QCA may determine the manner in which they can best be reconciled or which of them should prevail.

Within these parameters, the reference tariff principles are designed to provide a high degree of flexibility so that the reference tariff policy can meet the specific needs of each pipeline system. The overarching requirement is that when reference tariffs are determined and reviewed, they should be based on the efficient cost (or anticipated efficient cost) of providing reference services.

11. FORM OF REGULATION

The tariff arrangements detailed in an access arrangement are intended to be applicable for the length of a regulatory period. As any business transaction is subject to risk, those arrangements need to allocate that risk. 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.

11.1 Code requirements

With the approval of the QCA and consistent with the objectives contained in section 8.1 of the Code, the manner in which a reference tariff may vary within an access arrangement period is within the discretion of the service provider (section 8.3). For example, a reference tariff may be designed on the basis of:

(a) a 'price path' approach, whereby a series of reference tariffs are determined in advance for the access arrangement period to follow a path that is forecast to deliver a revenue stream calculated consistent with the principles in section 8 of the Code, but is not adjusted to account for subsequent events until the commencement of the next access arrangement period;

(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 continuously 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.

11.2 Issues in determining the form of regulation

The main issue with the form of regulation is the balance between certainty for suppliers and users of the service and the most appropriate allocation of risk. Risk imposes costs, through measures taken to manage the risk or through production or material losses arising from an event to which the risk pertains. In a sustainable business, those costs ultimately are borne by consumers, either through bearing the risks themselves or paying the service provider a premium for bearing those risks.

As noted above, the Code provides a choice between a 'price path' approach and a 'cost of service' approach, or some mix of these. Neither of these approaches, applied strictly, is likely to be consistent with efficient pricing principles, which would allow the party to handle risks who is in the best position to do so. Therefore, it is likely that either approach would lead to higher costs to the end user than a system allocating risk efficiently. The question is whether the costs of assigning risk appropriately, including costs associated with errors in this process, outweigh those associated with a more rigid system.

A strict price path approach provides certainty concerning the price over the regulatory period. However, this leaves all the risk with the service provider. Any increase in the cost of providing the service would be absorbed by the service provider.

On the other hand, a strict cost of service approach means prices would reflect actual costs at a given point in time. Therefore, this approach allocates all the risk to users of the service, including risks that the service provider could have managed or ameliorated. Under this approach, the service provider has little incentive to reduce risk or the potential cost of that risk.

A mixed approach may take the form of a price path, with variations or reviews in prices allowed on the occurrence of specified events, such as a change in taxes or government charges, or demand falling outside a nominated range from that forecast.

As the QCA needs to approve the initial reference tariffs, it also will have a role in changes to those tariffs. Where such changes arise because of changes in costs, the QCA could require the service provider either to:

- seek approval for any changes before they are made; or
- notify the regulator of any changes and the basis for these. In this case, there would need to be a process should the QCA not be convinced of the need for a price change, or for appeals by users against price increases.

Permitting a service provider to pass on increases in costs associated with certain events requires an appreciation of the effect of those events on the service provider's costs. For example, a change in environmental regulation may require service providers to change the way they operate. The effect on costs of this change depends on a number of things. The incentive for the service provider is to calculate the cost effect in a manner as favourable to the service provider as possible. In many cases, countervailing factors may reduce the effect on costs of a new measure. The service provider may also have opportunities to reduce the effect on costs by adopting the most efficient means of operation under the new regime. However, the service provider would have no incentive to do so, if the customer bore the risk of changes in costs. (Cost passthrough and tariff review also are discussed in Chapters of this issues paper dealing with *Incentive Mechanisms* and *Review Date* respectively.)

The timing of price reviews and increases also presents some issues. The effect of individual changes to the commercial and regulatory environment facing service providers may not be significant over the short term. That is, the compliance costs of establishing the basis for a price rise may exceed the cost associated with a single event such as a change in government regulation. This would be more likely should the regulator need to approve each price change. It may be more efficient to rely on a regular price review, say six monthly or annually. This would entail the service provider absorbing cost increases (or benefiting from a reduction in costs) until the next price review, unless an event occurred which would trigger a review of the access arrangement, as discussed in the relevant section of this issues paper.

Summary of access arrangement proposals

Allgas

Allgas has proposed a mixed approach, with a price path determined at the beginning of the regulatory period, with defined trigger events for review of this price path. The access arrangement provides for pass through of increases or reductions in imposts, such as royalties, certain taxes, duties and excises.

Envestra

Envestra has proposed a price path approach. The access arrangement states there will be no adjustment to the total revenue requirement or reference tariffs to reflect any differences between actual or forecast amounts for new facilities investment, non capital costs or gas delivery. The only exception to this approach is given in relation to increases or reductions in imposts, such as royalties, certain taxes, duties and excises, or costs arising from complying with directions from government or statutory authorities.

Other jurisdictions

Service providers in other jurisdictions have tended to adopt a mixed approach, with a price path employed subject to cost pass throughs associated with nominated events. Regulators have accepted this approach (with particular attention to the specific events listed and the process of how the cost pass through would be implemented).

The Authority seeks comment on whether:

- **a 'price path' or 'cost of service' approach, or a combination of these approaches, is preferred; and**
- **the access arrangement should set out specific events the cost effects of which would be passed on to consumers (and if so, what events should be specified), or a general process.**

12. DETERMINATION OF TOTAL REVENUE

Total revenue is the product of prices and the number of units sold. Total revenue can also be expressed as the amount needed to give the desired rate of return on the capital employed in the business and to cover costs. This section deals only with the method by which total revenue is calculated. Other sections deal with the component parts of the calculation, such as the rate of return, capital value, depreciation and non capital costs.

12.1 Code requirements

The Code (section 8.2) provides that total revenue is to be set on the basis of the sales of all services provided by the covered pipeline during the regulatory period.

The Code (section 8.4) also details three possible methodologies for determining total revenue:

- Cost of Service: where the total revenue is set to recover costs, calculated on the basis of a return on the value of the assets that form the covered pipeline, depreciation on the capital base and the operating, maintenance and other non capital costs incurred in delivering all services;

- IRR: where the total revenue is set to provide an acceptable internal rate of return (IRR) for the covered pipeline on the basis of forecast costs and sales; and

- NPV: where the total revenue is set to deliver a Net Present Value (NPV) for the covered pipeline (on the basis of forecast costs and sales) equal to zero, using an acceptable discount rate.

In addition, other methodologies that can be translated into one of these forms are acceptable (such as a method that provides a real rate of return on an inflation-indexed capital base).

12.2 Issues in determining the calculation of total revenue

Total revenue is the income to the service provider, for each of the services provided by means of a covered pipeline, from which it must meet all costs of providing those services and receive a return on its investment.

The Code provides wide discretion to service providers and regulators as to how total revenue may be calculated. However, the three nominated approaches have common elements, such as the rate of return, capital value, depreciation and non capital costs. While these methodologies provide different ways of assessing the total revenue, their outcomes should be the same. The calculation of each of these elements is discussed in later sections of this issues paper.

The cost of service approach provides a simple means of calculating an allowable total revenue, using a 'building block' approach, each of the elements of which is subject to approval by the QCA. The IRR and NPV methods are closely linked, in that the IRR is the discount rate required to give an NPV of zero (which is the point where the return on an investment exactly equals its cost of capital). However, the ability of the IRR method to give more than one answer for a given set of data presents a problem in using this approach.

The Code allows service providers to deal with the effects of inflation in any manner they choose, including using real or nominal bases. It is important that the treatment of inflation is consistent, whichever methodology is used to calculate total revenue.

The Code also allows the QCA to take a view as to an appropriate value for total revenue, based on any financial and operational performance indicators it considers relevant and consistent with the general objectives for reference tariffs listed in section 8.1 of the Code.

Summary of access arrangement proposals

Both distributors propose a cost of service approach. Envestra determines total revenue as inclusive of its special meter reading service. Whether total revenue should include such ancillary services is raised in the section of this issues paper dealing with Services Policy.

Other jurisdictions

Envestra (South Australia), AGL (New South Wales) and AlintaGas (Western Australia) each proposed a cost of service approach, which was accepted by the relevant regulators (SAIPAR 2000a, IPART 2000a and OffGAR 2000a respectively).

In Western Australia, CMS Gas Transmission for its Parmelia pipeline proposed a net present value (NPV) approach, with total revenue subsumed into the calculation of reference tariffs that return a NPV of zero. The regulator (OffGAR 1999) raised no issues with the approach.

In Victoria, Multinet, Westar and Stratus proposed a cost of service approach, using current cost accounting. The intention of this approach was to establish a real rate of return. The regulator (ORG 1998b) accepted this approach, together with the implied assignment of inflation risk to users.

The Authority seeks comment on whether a cost of service, Internal Rate of Return (IRR) or Net Present Value (NPV) approach is appropriate in determining total revenue.

13. THE INITIAL CAPITAL BASE

The value assigned to the initial capital base (ICB) in the first access arrangement for a pre-existing pipeline is one of the most significant issues to be addressed in setting regulatory prices. The determination of the ICB underpins the future revenue flows to accrue to the service provider. It is therefore crucial to ensuring an adequate return to pipeline or network owners while attempting to provide users with prices which replicate those likely to have arisen in a competitive environment.

13.1 Code requirements

The Authority is required by the Code to consider a number of factors associated with the pipeline in approving the initial capital base. Once established, the base remains unchanged over the life of the assets, excepting adjustments for new facilities, depreciation and, where appropriate, redundant capital. This inability to revise the ICB in future regulatory reviews is of particular interest in the context of the Queensland market and is the subject of further discussion later in this paper.

Section 8 of the Code sets out the applicable principles for establishing the ICB. In setting the capital base for the first access arrangement period, the Code differentiates between pipelines that came into existence before (sections 8.10 and 8.11) and after (sections 8.12 and 8.13) the commencement of the Code.

The initial capital base – existing pipelines

In establishing the value to be assigned to the ICB, section 8.10 of the Code requires (among other things) that the Authority consider the depreciated actual cost (DAC) and the depreciated optimised replacement cost (DORC) of a pipeline. However, while there is flexibility regarding the chosen methodology, section 8.11 states that the ICB should not normally fall outside the range bounded by DAC and DORC (effectively the lower and higher bounds respectively).

The Authority is also required to have regard to a number of other factors, including:

- other well recognised asset valuation methodologies and the advantages and disadvantages of these methodologies;
- international best practice and the impact of asset valuation on the international competitiveness of energy consuming industries;
- the basis on which tariffs have been (or appear to have been) set in the past, including economic depreciation and historical returns;
- the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code;
- impact on the economically efficient utilisation of gas resources;
- comparability of the cost structure of a new pipeline which may compete with an existing pipeline;
- the price paid for any asset recently purchased by a service provider and the circumstances of that purchase; and
- any other factors the Authority may consider relevant.

Initial capital base – new pipelines

For those pipelines built after the commencement of the Code but prior to the commencement of the first access arrangement period, the ICB is set, subject to section 8.13, at the actual capital cost of those assets at the time they first entered service (section 8.12).

However, if a sufficient period exists between the time the covered pipeline first entered service and the time the reference tariff is proposed, section 8.13 allows for adjustments to be made to the actual capital cost if it is appropriate, for example, to account for new facilities investment (or the recoverable portion), depreciation and redundant capital incurred or identified.

13.2 Issues in determining the initial capital base

As noted above, the Authority is required to consider well recognised asset valuation methods, including their advantages and disadvantages. A range of such methods are outlined below.

Historical cost

Historical or *actual cost* uses the actual dollar cost of acquiring the asset, including the relevant financing cost during construction and installation, as the value of the asset. Capital assets are therefore valued at their original cost. *Depreciated actual cost* (DAC) adjusts actual cost to account for the age of the original assets, that is, through depreciation. DAC or historical cost has been a widely accepted method for public reporting purposes in the private sector.

A variant of the historical cost approach, *inflation adjusted actual cost*, attempts to adjust the asset value for inflation. This can be done by revaluing assets according to some broad indicator of the price level (for example, CPI).

Reproduction cost

Reproduction costs are those costs required to reproduce the existing plant in substantially its present form using the production technology and specifications of the original asset. This approach is most relevant where a similar asset is available and the existing asset still represents largely unchanged technology. Depreciated reproduction cost adjusts reproduction cost to account for the age of the actual assets.

Replacement cost

The *replacement cost* of an asset is an estimate of the current cost of replacing the asset with similar assets, which can provide equivalent services and capacity to the asset being valued. That is, it measures what it would cost today to provide an asset to deliver the same service potential as the asset being valued.

Depreciated replacement cost

Depreciated replacement cost adjusts replacement cost to account for the age of the assets, that is, through depreciation. This method therefore estimates the net current cost of replacing the asset in its current (partly worn out) state with an asset which has a similar service potential. Asset replacement costs need to be depreciated where the existing asset's remaining service life is less than the life that would normally be expected from a new asset. The depreciation effectively recognises the limited remaining life.

Optimisation

Assets may exhibit excess capacity, be over-engineered, be sub-optimally designed (for example, having regard to technological advancements) or be poorly located. Consequently, a valuation system may incorporate an *optimisation* process to evaluate whether physical assets are in excess of current requirements.

The process of optimisation is about identifying the most efficient facilities necessary to produce a specified level of services. By removing excess capacity and redundant services from the valuation process, and reconfiguring the network to remove any poor locational decisions, values are set based on the most efficient configuration of assets that could be used to deliver the service.

Depreciated Optimised Replacement Cost (DORC)

Depreciated Optimised Replacement Cost (DORC) measures the cost of providing equivalent services in the most efficient way possible, from an engineering perspective, while allowing for the age of the existing assets through depreciation.

The application of DORC involves the following steps:

- optimising the distribution system;
- calculating the replacement cost of the optimised asset base; and
- determining asset depreciation.

Net Realisable Value (NRV)

The *net realisable* or *fair market* value is simply the price at which an asset will sell in a competitive open market. This reflects the value of an asset in its next best alternative use.

Net Present Value (NPV)

The *net present value* or *discounted cash flow* approach values an asset as the present value of the predicted cash flows likely to be generated from the use of the asset. This involves estimating the future income generated from an asset and then discounting the income streams at a rate which reflects the risks involved in owning the asset. The present value of the predicted future income stream then becomes the current value of the asset. This method is widely used in valuation for investment purposes.

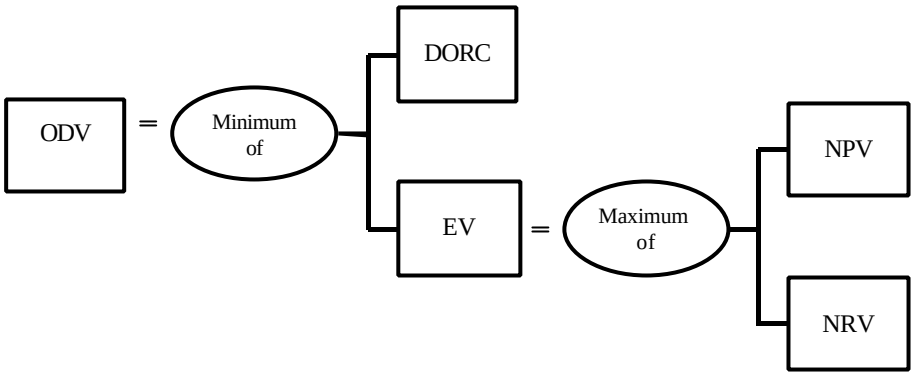
Deprival Value (DV)

Deprival value is the value of an asset to the owner in terms of the loss that would be incurred by the owner if deprived of the asset, and is calculated as the lesser of the depreciated replacement cost of the asset and the economic value (EV) of the asset, where the latter is the maximum of the asset's net present value of financial returns to the asset (on a cash flow basis) or net realisable value.

Optimised Deprival Value

Optimised Deprival Value (ODV), as illustrated in Figure 13.1, is defined as the lesser of the replacement cost of the asset, adjusted for optimisation and depreciation, and the EV of the asset, where the latter is the maximum of the asset's net present value of financial returns to the asset (on a cash flow basis) or net realisable value.

Figure 13.1: ODV valuation



Source: Adapted from NZ Ministry of Commerce (1998)

Advantages and disadvantages of valuation methods

DAC has several advantages as an asset valuation methodology, including:

- it is relatively inexpensive to establish and simple to administer so long as asset registers are complete and data is comparable across assets and time;
- it reduces the risk of technological change for asset owners. When an investment is made, the schedule of allowed returns under DAC depends solely on the depreciation schedule set by the price setting body. In contrast, the allowed returns under other current cost methodologies will vary whenever relevant input prices or the prices of alternative technology change;
- for assets with a relatively brief useful life, DAC provides the advantage that it is consistent with a real measure of current cost and also represents the basis on which the owner assessed the potential returns and expended capital; and
- it avoids the costs and subjectivity associated with determining current asset values.

However, there are also several disadvantages associated with DAC, including the fact that calculations require historical data from asset registers that may be incomplete or non-existent, as well as difficulties associated with the different accounting standards on capitalisation and rates of depreciation when considering very long periods of time. In addition:

- DAC, especially in the case of long-lived assets, may have little or no relationship with market values or replacement costs. For example, persistent inflation causes capital valuation and capital costs to be underestimated relative to current values. DAC also takes no account of technological obsolescence; and
- valuations based on DAC would make tariffs dependent on asset age and could lead to price shocks when assets are replaced.

DORC has several advantages, including:

- it ensures that obsolete, poorly sized or poorly located assets are not included in the capital base and consequently are not paid for by users;
- it allows for technological change (that is, assets can be valued in a way that reflects current technology rather than outdated technology); and
- it addresses a major problem of DAC, namely, the incompatibility in relating historical values for capital assets and capital costs with current values for other expenses and revenues.

Disadvantages of DORC include:

- examination and assessment procedures are costly and judgement is required in determining the optimal network configuration and the degree of excess capacity deemed to be 'efficient'; and
- the complexity of the process may be magnified by the asymmetry of information between the price setting body and the network owner.

Optimised deprival value applies the minimum of DORC or economic value. Advocates of the deprival methodology argue that this approach better aligns asset valuations with those produced in a competitive market. In practice, if DORC exceeds EV, an owner would not replace the asset because the present value of future earnings would be less than the cost of replacing the asset. Alternatively, if EV exceeded DORC, the present value of future earnings would exceed the cost of replacing the asset.

In addition to the advantages associated with using DORC, deprival value may result in a more accurate value for an asset in an environment where a full DORC valuation provides an asset value, and consequently a price, that cannot be supported by the market. In some circumstances, the resulting asset value has been expressed as a percentage of the full DORC calculation.

However, the use of economic value concepts (for example, NPV or NRV) can have circularity problems. In a regulated market, the asset value is used as an input in calculating the revenue requirement, and consequently the price. Subsequently, any attempt to use the price to determine an asset value, which in turn is used as an input into the price, suffers from a problem of circularity. To the extent that there is competition in the market, for example, from other networks or other energy sources, determination of a market based price may be possible, which may mitigate this circularity problem.

Specific issues in the context of the Queensland gas market

The Code establishes a national access regime for natural gas pipeline systems. The objective of the Code is to establish a framework for third party access to gas pipelines that (among other things) facilitates the development and operation of a national market for natural gas. However, the Code contains some provisions that, in certain circumstances, could be the very antithesis of these intentions.

As noted above, the Authority is required by the Code to consider a number of factors in approving an initial capital base. Once established, the ICB is unable to be revised in future regulatory reviews excepting adjustments for new facilities, depreciation and, where appropriate, redundant capital. However, where for some reason, such as market immaturity, the value of the ICB could potentially be increasing over time as network utilisation grows, the restriction on asset revaluations for regulatory purposes potentially creates a significant distortion. The Queensland gas industry is particularly vulnerable to any such distortion due to the market's relative immaturity and the subsequent under-utilisation of its existing assets.

By way of an example, given there is no capacity to revalue the ICB in subsequent regulatory reviews, an affected service provider would have little incentive to take action which would result in an increase to the value of an existing pipeline (such as by seeking to increase usage of existing customers or to increase penetration of gas in the energy market). Such an outcome would be inconsistent with the intentions of the Code.

Also, the inability for the ICB to be revised in subsequent reviews contrasts sharply with the National Electricity Code. In the latter, asset revaluations for regulatory purposes are generally undertaken at the beginning of each access arrangement period. To the extent that gas competes in the same national energy market as electricity, this difference in approach to the setting and revisiting of capital values potentially creates distortions within that market.

This potential for unintended inconsistencies between the Code's objectives and possible outcomes could be addressed through several mechanisms. In particular, there is scope to ameliorate the problem through the use of inflated demand forecasts in conjunction with redundant capital provisions, or the use of negative (or economic) depreciation. (See Chapter 14: *Rolling Forward the Capital Base* for a discussion of these approaches.) Other jurisdictional regulators in recent decisions have adopted these approaches to overcome this limitation in the Code.

Summary of access arrangement proposals

Allgas

Allgas has proposed that a DORC valuation is the most appropriate method for determining the ICB. The proposed access arrangement argues that the DORC of the assets is a measure of the cost of replicating the system in the most efficient way possible, from an engineering perspective, given the service capability and age of existing assets. The valuation is built up as the sum of the value of the individual asset groups.

The proposed optimisation process involved adopting standards in the valuation which, it is argued, are comparable to those of other gas utilities in Australia. In addition, Allgas formulated a series of work procedures to comply with the occupational, health and safety requirements as well as with current environmental Acts. The replacement cost of mains and inlets were assessed in the context of brownfields conditions while the optimisation took into consideration construction practicalities (for example, in some areas a 25 mm diameter main may theoretically be possible but a 40 mm diameter is the minimum practical main size as the industry standard) and applied a five year planning horizon in terms of expected demand growth.

Depreciation was based on a straight-line profile using a standard economic life for each asset type, together with an estimate of the remaining life of each asset. Thus, if an asset had a standard economic life of 40 years and a remaining life of 10 years, it would be depreciated to 25 per cent of its replacement cost.

The Allgas DORC valuation for network assets has been set at $181.403 million as at 30 June 1999.

Envestra

Envestra considered a number of different approaches to the valuation of system assets. However, the access arrangement argues that DORC is the most appropriate method for valuing the ICB for the network on the basis that this approach meets the requirements of the Code and has a number of practical advantages.

The DORC methodology adopted by Envestra involved valuing the assets based on the cost of a new modern equivalent asset (using current technology) that is optimally sized and configured to deliver existing levels of service, less an allowance for depreciation.

Depreciation is on a straight-line basis. While most assets have been assumed to have a zero residual value, Envestra recognises that certain mains and inlets have the ability to be inserted with new polyethylene once they have reached the end of their useful life. Envestra argues that the potential to insert polyethylene pipe, and the lower cost of insertion compared with that of direct burial, gives rise to a residual value associated with the conduit value (or 'hole in the ground' value) of such mains and inlets. This residual value is defined as the difference between the cost of insertion and the cost of direct burial of new mains and inlets. The use of this residual value approach has the effect of reducing the amount of annual depreciation where the asset age is greater than the age at which the residual value sets in. It also results in a higher capital base value because of the lower level of depreciation.

The Envestra DORC valuation for network system assets has been set at $195.5 million as at 30 June 1999.

Other jurisdictions

The Authority notes that DORC valuations have been commonly viewed by other regulatory agencies in Australia as a 'starting point' for asset valuation. A summary of approaches to asset valuations is provided in Table 13.1.

Table 13.1: Initial capital base for gas transmission and distribution systems

Entity/Author	Industry	Basis for valuation of the ICB	% of DORC
ACCC (1998)	Gas transmission	DORC value, adjusted downward by approximately 2.8 per cent to avoid tariff increases	97%
ACCC (2000b)	Gas transmission	DORC value incorporating negative depreciation (but nominally equivalent to the DAC value as this is a new pipeline – 12 months old at the time of valuation)	111%
ORG (1998b)	Gas distribution	DORC value, adjusted downward by between zero and 8 per cent for different parts of the distribution systems in order to avoid tariff increases	94%
IPART (1999f)	Gas distribution	DORC value, adjusted downwards by approximately 7 per cent to avoid network price differentials	93%
IPART (1999d)	Gas distribution	Value determined at an approximate mid point between DAC and DORC values on the basis of a balance of interests between the service provider and users providing for reasonable financial outcomes for the service provider and real reductions in tariffs	77%
IPART (1999b)	Gas distribution	Value determined between DAC and DORC values on the basis of impacts on tariffs and a balancing of interests between the service provider and users	86%
OffGAR (2000b)	Gas transmission	Value based on the optimised deprival value of the pipeline, impacts on tariffs and a balancing of interests between the service provider and users, and subject to a redundant capital policy that will see the value reduced if forecast market growth does not eventuate	95%
OffGAR (2000a)	Gas distribution	Value based on (a version of) deprival value of the pipeline, incorporating consideration of impacts on tariffs and a balancing of interests between the service provider and users	76%
SAIPAR (2000a)	Gas distribution	100 percent of DORC value as determined by the regulator, which was below the DORC calculation provided by the regulated entity	100%

A number of jurisdictional regulators have derived ICB values through an approach whereby initial DORC values are established and then subsequently reduced on the basis of a balancing of interests of the service provider and users.

For example, ORG (1998b) in its final decision on the Multinet, Westar and Stratus networks, set the value of the ICB initially at DORC, but wrote down this valuation sufficiently to ensure that the stated policy objectives were met (in this case, the policy objective being the prevention of tariff rises to small customers in some outlying areas). Similarly, IPART (1999f), in its recent decision on the Albury Gas Company's distribution pipeline, concluded that there is no significant economic argument requiring that the ICB be founded on DORC and that an amount (approximately 7 per cent) less than DORC strikes a reasonable balance between the interests of stakeholders and the promotion of competitive outcomes.

However, the recent draft decision by SAIPAR (2000a) on Envestra's South Australian distribution system considered that 100 per cent of the DORC valuation was the most appropriate value for the ICB. In making this decision, SAIPAR considered the valuation as being in the interests of users and the service provider and concluded that failure to establish an appropriate DORC would ultimately result in a contraction in the scale and scope of services being provided.

The ACCC (2000b) in its final decision on the Central West Pipeline adopted what is described by the service provider as a DORC valuation. However, this approach differs to the generally accepted DORC valuation in that it applies what the ACCC calls negative depreciation to the Optimised Replacement Cost, which has the effect of increasing the valuation. Normally an adjustment to account for depreciation would be expected to result in a decreased valuation, reflecting the fact that part of the asset's life has already been used. However, in this case, the pipeline incurs negative depreciation during the earlier phase of its lifetime such that initial under-recovery of costs is reflected in an increase in the asset value, with the costs to be recovered in later periods. The resulting valuation is outside the range the Code considers is generally appropriate for asset valuations (that is, between DAC and DORC).

The adoption of the negative depreciation principle is further discussed in Chapter 14: *Rolling Forward the Capital Base.*

In contrast to the adoption of DORC valuations for the purpose of calculating the ICB, OffGAR (2000a and 2000b) in its decisions on the Parmelia and AlintaGas pipelines, applied what has been described as an optimised deprival valuation of the asset base. While the valuation methodology is not entirely consistent with the strict definition of ODV (which is explicitly recognised by OffGAR it its decisions), there is a general similarity between approaches. OffGAR concluded that the use of its version of ODV is the most appropriate method for valuing the ICB (noting that, depending on assumptions of future throughput, the value derived by this methodology may be equal to DORC). However, OffGAR recognised the difficulties with its version of ODV in that it depends upon expectations of future costs and revenues of the pipeline – expectations which cannot be known with any certainty.

OffGAR also noted that a conservative ODV (calculated from current throughput and tariffs) may be unduly harsh on the service provider in that it does not allow for an asset value associated with potential market growth – a problem compounded by the fact the Code does not provide for an ICB to be revised upwards if the initial valuation was to prove too conservative. On the other hand, a more lenient treatment of the ICB that takes into consideration expectations of market growth may unreasonably penalise users.

In balancing the interests of the service provider and users, OffGAR concluded that a value of the ICB greater than the conservative ODV which reflects expectations of market growth, may be acceptable as long as the service provider bears the risks if expectations of market growth are not realised. To this end, the final decision required that the Redundant Capital Policy provide for the capital base to be reduced at the end of the initial access arrangement period if the expectations of market growth are not realised. The risks of market growth expectations not materialising therefore rest with the service provider, while at the same time allowing for an asset value associated with potential market growth.

Where market growth expectations are not realised in the first access arrangement period, that portion of the assets not contributing to the service provision would be removed from the asset base and added to the Redundant Capital Value. However, should that capital subsequently contribute to the delivery of services in later access arrangement periods (for example, as a result of market growth) the redundant capital provisions of the Code provide for the capital base to be increased up to an amount equivalent to this value.

IPART (1999b) also made a judgement to adopt ODV in certain circumstances. In this decision, detailed ORC and DORC asset valuations were obtained which were in turn allocated to various segments of the contract and volume market. IPART made the judgement that pricing in the contract market would sustain DORC asset values, which were then used for this segment of the market. For the volume market, IPART made the judgement that regulatory constraints would prevent pricing in excess of current levels, and accordingly, an economic valuation based on ODV was calculated for that market.

The Authority seeks comment on the use of the different asset valuation methodologies outlined above in establishing reference tariffs for Queensland gas distribution networks, and in particular DAC, DORC and ODV, including their implications for investment and pricing decisions and any potential difficulties with their implementation.

The Authority particularly seeks comment on the approaches adopted by other regulators with a view to providing an avenue by which initial asset values may be adjusted in future years to reflect increased utilisation of existing assets.

The Authority also seeks comment on whether the initial capital values proposed by gas distribution network owners are fair and reasonable and whether they meet the requirements of the Code.

Comment is also sought on Envestra's proposed approach which recognises the potential for insertion for some mains and inlets, and proposes that there be a value attached to the associated 'hole in the ground' for asset valuation purposes.

14. ROLLING FORWARD THE CAPITAL BASE

Once the value of the initial capital base (ICB) has been established, the capital base for each subsequent period must be determined. This value will be the ICB increased to recognise additional capital costs incurred in constructing new facilities, less an allowance for depreciation. In addition, any assets that may have ceased to contribute to the delivery of services will need to be removed.

14.1 Code requirements

The Code is quite prescriptive in relation to adjusting the asset base in subsequent regulatory reviews with specific provisions covering the treatment of:

- new facilities investment (sections 8.15-8.17) and speculative investment (section 8.19);
- redundant capital (section 8.27); and
- depreciation (sections 8.32-8.35).

The provisions for the rolling forward of the capital base can be expressed as follows:

Regulatory capital base = initial capital base + new facilities investment (excluding speculative investment) – depreciation – redundant capital

The Code therefore does not provide for the revaluation of the initial capital base but does provide for indexation of the capital base.

New facilities investment

Sections 8.15 and 8.16 of the Code provide for the capital base to be increased to recognise additional capital costs incurred in constructing new facilities for the purpose of providing services. The amount of the increase is the actual capital cost, provided that the investment is prudent in terms of efficiency, in accordance with accepted industry practice and is designed to achieve the lowest possible cost of delivering services.

If the incremental revenue is not expected to exceed the cost of the investment, the service provider (and/or users) must satisfy the Authority that the new facility has system wide benefits (justifying higher tariffs for all users), or that the new facility is necessary to maintain system safety, integrity or contracted capacity of services.

Under sections 8.18 and 8.19 of the Code, a service provider may undertake new facilities investment if these criteria are not met. However, where a service provider incurs such new facilities investment, the capital base may only be increased by the extent to which the investment does satisfy section 8.16 (the recoverable portion). That part of the investment which does not satisfy the requirements (the speculative investment) is held in a speculative investment fund and may be added to the asset base at a later date when it does meet the section 8.16 criteria.

Reference tariffs may also take account of forecast new facilities investment which the service provider is expected to incur within the access arrangement period, provided that when the investment is forecast to occur it is reasonably expected to pass the requirements of section 8.16. However, allowing the forecast investment to be incorporated into the reference tariff calculations need not imply that such investment will meet the requirements of section 8.16 when the Authority considers revisions to the access arrangement. Section 8.22 of the Code also notes that the reference tariff policy should specify how discrepancies between forecast and actual investment are to be reflected in the capital base at the commencement of the next regulatory period (so as to best meet the objectives in section 8.1 of the Code).

Capital redundancy

Section 8.27 of the Code allows a reference tariff policy to include (and the Authority 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 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 between the service provider and users.

Before approving such a mechanism, the Authority must take into account the uncertainty such a mechanism would have on the service provider, users and prospective users.

Where redundant assets subsequently contribute to the delivery of services, section 8.28 allows the assets to be added back into the asset base as if they were new facilities investment, subject to the associated criteria noted above. The value of the redundant capital is to be increased annually on a compounded basis by the rate of return allowed on capital assets that form the covered pipeline, from the time it was removed from the asset base (section 8.28).

Depreciation

Depreciation is an asset-related cost that measures the decline (ordinarily) in service potential of an entity's asset base over time as its useful life becomes shorter. That is, it represents the return of capital to the service provider. From an accounting point of view, a depreciation charge is important because it matches the decline in the asset value with the revenue generated by the asset base.

For the purpose of determining reference tariffs, sections 8.32 and 8.34 of the Code specify rules for depreciation of assets that form part of the capital base.

A depreciation schedule is defined as 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 purpose of determining a reference tariff.

The depreciation schedule is required to 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 tariff 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 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 an adjustment for inflation (if any) as is appropriate given the approach to inflation adopted pursuant to section 8.5A).

Section 8.34 translates certain detailed principles into a form that is applicable where the IRR or NPV methodology 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.

14.2 Issues in the treatment of new facilities investment

The Code sets out broad principles for valuing investment in new facilities. However, a number of issues arise in applying these principles, such as determining whether new facilities investment is prudent, and addressing differences between forecast and actual capital expenditure. A further issue arises when considering how new facilities investment is to be rolled into the capital base, and in particular whether some form of averaging of the asset base can be used on a year to year basis to smooth the addition of new facilities investment.

Summary of access arrangement proposals

Allgas

Allgas has identified the following key drivers of capital expenditure:

- customer driven works – works associated with new or upgraded connections (such as mains laying, service and metering installations);
- network augmentation works – works required to augment the existing system to ensure that safety, environmental and other service standards are maintained;
- mains renewal program – works to replace or insert existing mains; and
- non-system asset expenditure – additional assets required to carry out the management of the network.

Allgas has not undertaken a full-scale mains renewals program to date. However, a mains renewal program has been factored into the capital expenditure program.

Allgas' new facilities investment forecasts out to 2004-05 are reproduced in Table 14.1.

Table 14.1: Allgas forecast new facilities investment ($m, nominal)

	2000-01	2001-02	2002-03	2003-04	2004-05
Customer requested	4.560	5.503	5.014	5.191	5.321
Augmentation	1.107	2.939	2.755	0.570	0.585
Network renewal	4.273	5.068	4.455	4.611	4.726
Non-system	0.300	0.307	0.315	0.323	0.331
Total	10.240	13.817	12.539	10.695	10.963

Allgas' proposed access arrangement states that the asset value used for revenue determination purposes for each year of the access arrangement period is calculated as follows:

Average Asset Value$_n$ = (Opening asset value$_n$ + Closing asset value$_n$)/2 where

Closing Asset Value$_n$ = {(Opening asset value$_n$ – depreciation$_n$ – disposals$_n$) * (1 + CPI%)} + Capex$_n$

The above formula has the effect of averaging the opening and closing asset values in a given year for the purpose of determining total revenue.

No specific reference has been made in the access arrangement to issues such as the treatment of capital expenditure that does not satisfy section 8.16 of the Code, or to the method by which discrepancies between actual and forecast capital expenditure are to be treated.

Envestra

Envestra's proposed reference tariff policy states that any new facilities investment that is included in the network and satisfies the test detailed in section 8.16 of the Code, will be added to the capital base at the commencement of the next access arrangement period. Where only part of any new facilities investment satisfies section 8.16 of the Code (the recoverable portion), the capital base will only be increased by that portion which satisfies section 8.16.

Where part or all of any new facilities investment does not satisfy the requirements of section 8.16 of the Code, Envestra has proposed that it may apply to the regulator to impose a surcharge, or agree to a capital contribution with a user in accordance with its proposed extensions and expansions policy.

New facilities investment forecast during the access arrangement period is based on the forecast level of capital expenditure required to allow Envestra to meet the forecast growth in demand for haulage services and to meet system augmentation and replacement requirements.

New facilities investment forecast for the access arrangement period falls into two categories:

- growth capital – capital required to extend the network into new areas, based on Envestra's demand growth forecasts; and
- replacement capital – capital required to maintain the integrity of the network in the accelerated mains replacement program (AMRP).

Envestra's new facilities investment forecast out to 2005-06 is reproduced in Table 14.2.

Table 14.2: Envestra forecast new facilities investment ($m, nominal)

	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Growth Capital	6.1	5.2	5.6	5.9	6.3	6.4
Replacement Capital	3.8	6.8	6.9	6.7	6.9	6.5
Total	9.9	12.0	12.4	12.6	13.3	12.9

In calculating Envestra's total revenue requirement, the revenue equation reflects the proposed initial capital of $195.5 million as at 30 June 1999, adjusted to take account of actual new facilities investment, redundant capital and depreciation during 1999-00 and forecast new facilities investment, redundant capital and depreciation during 2000-01. In each subsequent year, the capital base will continue to be adjusted to reflect forecast new facilities investment, redundant capital and depreciation.

The asset value used for revenue determination purposes for each year of the access arrangement period is calculated as follows:

Average asset value $_n$ = (Opening asset value $_n$ + Closing asset value $_n$)/2, where

Closing asset value = Opening asset value $_n$ + inflation on opening asset base$_n$ + new facilities investment$_n$ - depreciation$_n$

Other jurisdictions

Generally, service providers have directly inserted (or the relevant regulator has required the service provider to insert) into their access arrangement the relevant provisions of the Code relating to new facilities investment.

The Authority seeks comment on whether the capital expenditure forecasts of each service provider meet the requirements of section 8.16 of the Code in general, and whether they (and the demand forecasts they are based on) are fair and reasonable.

The Authority also seeks comment on whether the proposed access arrangements adequately address the issue of speculative investment.

14.3 Issues in the treatment of redundant capital

The Code also sets out principles for reducing the capital base where assets cease to contribute, or make a reduced contribution, to the delivery of services. These provisions seek to ensure that assets which cease to contribute to the delivery of services are not reflected in the capital base and to share between the service provider and users costs associated with a decline in the volume of sales.

Recent regulatory decisions have also made use of redundant capital provisions to solve other issues. For example, in its final decision on the Parmelia pipeline, OffGAR (2000b) approved an asset value significantly above the current economic or market value of the pipeline, predicated on the use of the redundant capital provisions. In the final decision, the asset value reflects an assumption regarding future demand for gas that allows for significant market growth. In effect, while the asset value is set well above the market value, demand forecasts are also adjusted upwards, so that the final price faced by existing users remains broadly unchanged.

OffGAR approved the above approach on the proviso that a mechanism be put in the access arrangement that would see the capital base reduced at the end of the access arrangement period if expectations of market growth were not met. That is, the redundant capital provisions were used as a means of supporting a higher ICB. The regulator adopted this approach as it considered that the service provider should be given the opportunity to raise demand, and have this reflected in the capital base, given that the Code prevents revaluations of the ICB.

This approach has the dual benefit of providing for asset values to increase in line with market growth, while at the same time ensuring that the associated risks are primarily borne by the service provider.

This is one option for dealing with the current under utilisation problem faced by Queensland gas distributors. While asset values will be preserved, since any assets excluded as redundant capital can be brought back into the asset base as utilisation increases, the distribution network owner would be able to increase the regulatory asset value (potentially up to DORC) if demand increases.

Summary of access arrangement proposals

Allgas

Allgas' proposed access arrangement provides that the capital base shall be reduced based on the following principles:

- any assets that cease to contribute to the delivery of services shall be removed from the capital base; and

- the value attributable to the assets that are sold shall be removed from the capital base.

The access arrangement does not contemplate a situation where assets that have been declared as redundant capital subsequently contribute to, or make an enhanced contribution to, the delivery of network services.

Envestra

Envestra's proposed access arrangement provides that where assets cease to contribute, or where assets are sold, those assets shall be removed from the asset base.

If assets that have been declared as redundant capital subsequently contribute or make an enhanced contribution to the delivery of network services, the assets will be treated as a new facility, having new facilities investment equal to the redundant capital value increased annually on a compounded basis by the rate of return (applicable to that period) from the time the redundant capital value was removed from the capital base.

Other jurisdictions

Generally, effect has been given to the redundant capital provisions across the various jurisdictions by inserting the relevant provisions as per section 8.27 of the Code directly into the access arrangements (either voluntarily or at the direction of the relevant regulator).

The Code requires the relevant regulator to take into account the uncertainty a redundant capital mechanism would cause, and the effect of the uncertainty on service providers, users and prospective users. However, the ACCC's final decision on the Central West Pipeline, for example, stated that the regulator did not consider such a mechanism materially increases uncertainty.

The Authority seeks comment on whether the redundant capital policies proposed by the service providers will adequately ensure that costs associated with a decline in volume of sales are shared between the service provider and users.

14.4 Issues in the treatment of depreciation

Depreciation seeks to measure the decline in service potential of an asset as a result of wear and tear, ageing or obsolescence. To put this another way, the value of many assets declines as they are used to generate revenue. The progressive 'using up' of the asset is therefore balanced against the revenue the asset earns in each accounting period, as a return of the investment in that asset to the asset owner.

Depreciation represents a significant component of the total revenue requirement for regulated entities such as capital intensive gas distribution networks. However, the Code has no specific requirements on how depreciation is to be treated, although, as noted above, the Code provides that the depreciation profile can be structured such that reference tariffs are consistent with efficient market growth. This has resulted in a number of significant deviations from generally accepted depreciation methodologies (as noted in Chapter 13: *The Initial Capital Base*). In addition, accounting requirements under the Australian Accounting Standards Board, the reporting requirements of Corporations Law and the requirements of federal taxation laws may impose particular conditions on entities with respect to depreciation, or make particular approaches to depreciation more attractive to entities.

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

- the asset 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;

- 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 asset 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. The three stages of calculation of distribution prices which will require consideration of depreciation are:

- the initial value of the asset base (for example, if depreciated optimised replacement cost is the preferred approach);

- the closing value of the asset base at the end of the regulatory period; and

- the method of allocating the change in value across this period.

For most assets, service potential diminishes over time primarily as a result of ageing, use and obsolescence. As the service potential of the assets declines, so too will the price an investor will be prepared to pay for the asset.

Summary of access arrangement proposals

Allgas

Allgas has proposed to utilise a straight-line approach in the determination of depreciation for the capital base, citing a number of reasons why this method is appropriate. Future year depreciation has been forecast by taking the base depreciation, escalating this for asset indexation as appropriate and then adding depreciation associated with capital expenditure.

Envestra

Envestra has proposed that depreciation be calculated on a straight-line basis.

Other jurisdictions

While there has been a general consistency among service providers and regulators to adopt a straight-line depreciation methodology, some decisions have deviated from this approach. For example, the ACCC's recent final decision on the Central West Pipeline (2000b) approved what it has termed an economic or negative depreciation approach. This concept provides a mechanism where under-recovery of costs in the early years can be offset by over-recovery in latter years. The ACCC defines economic or negative depreciation in the following manner:

Economic depreciation = total revenue – operating costs – return on capital

This is, however, not the traditional definition of economic depreciation.

Under the ACCC's definition, economic depreciation can be either positive or negative. It is deducted from (or added to) the capital base each year to reflect the extent that total revenue has covered costs. In the case of the ACCC's decision regarding the Central West Pipeline, the methodology results in negative depreciation during the first phase, which has the effect of increasing the asset value for regulatory purposes. The residual value at the end of the initial access arrangement period is greater than the initial capital base at the start of the period. This has the effect of increasing rather than decreasing the capital base over time.

However, this approach raises two potential issues – the threat of bypass and its effect on efficient pricing.

As the pipeline is relatively new, the continual use of negative depreciation will result in the pipeline having a carrying value for reference tariff purposes well above ORC. ORC effectively sets a maximum value that can be placed on assets because, unless legally or contractually prohibited, any valuations higher than ORC would enable a competitor to bypass the assets (for example, by duplication of the network or some section of it).

This then has second-round effects. That is, the service provider intends that tariffs will be sustained above long run costs during the period when the economic value of the asset for regulatory purposes exceeds ORC. Clearly, this approach to the reference tariff framework does not necessarily produce efficient pricing. However, this approach was preferred as it allows for costs to be under-recovered in the initial years of the pipeline's life, with a view to encouraging market development.

Nonetheless, the economic depreciation argument was accepted by the ACCC (albeit, not without some reservations) as it was argued that it is unlikely that alternative pipelines would be available to users and potential users of the pipeline.

The economic depreciation approach is similar to that adopted in the access arrangements approved by ORG in its final decisions on the Mildura and East Gippsland pipelines. In all three cases, the pipelines in question were greenfield sites with large market growth potential, and all cited the economic (negative) depreciation as enabling reference tariffs to be kept stable over the access arrangement period and the life of the asset, and being consistent with the growth of the market.

This approach is also an option for dealing with the under utilisation problem faced by Queensland's gas distributors, as it may assist in keeping prices low for a period of time to enable the market to grow.

The Authority seeks comment on whether the depreciation profiles identified in the proposed access arrangements adequately address the requirements of the Code.

The Authority also seeks comment on the appropriateness of the use of economic (or negative) depreciation as a means of addressing Queensland's current under utilisation problem.

15. RATE OF RETURN

One of the most significant issues to be addressed in any process to set regulatory prices for the services provided by a business activity involves the determination of the allowed rate of return for the assets involved in that activity. The rate of return is a forward looking concept based on estimated future returns and future expected risk. It represents the return expected by investors in capital markets for investments of a given level of risk. It should provide a stream of income from the investment of funds that would be sufficient to attract and retain that investment. The rate of return is, essentially, the opportunity cost to investors to compensate them for the expected returns on foregone investment opportunities (that is, the expected return on the next best alternative asset).

In competitive capital markets, the rate of return is determined by the forces of supply and demand for capital. Accordingly, the rate of return should provide a return to investors that is commensurate with the returns available from other assets of similar risk. However, for a regulated entity, the rate of return is established by the regulator. In such a case, the rate of return should be set at a level that is equal to the cost of attracting capital to fund a particular asset given its level of risk, that is, commensurate with what would be expected in a competitive market. If the allowed rate of return is too high, the prices charged to end consumers will be above the level that is truly reflective of costs. If the allowed rate of return is too low, investment by asset owners will be constrained and the quality of service offered to customers may decline.

15.1 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.

By way of example, the Code notes that the rate of return may be set on the basis of a weighted average of 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 QCA is satisfied that to do so would be consistent with the pricing objectives in the Code.

15.2 Issues in determining the rate of return framework

The rate of return for a group of assets used in a particular business activity can be derived by calculating the appropriate Weighted Average Cost of Capital (WACC). A firm's WACC recognises that its capital is provided by two sources, namely lenders and equity investors (that is, owners or shareholders), and is equivalent to the weighted average cost of servicing the various classes of financial claims on the firm. Each source of capital or financial claim will involve different risks and hence different costs. A firm's WACC is calculated by adding the cost of its debt, weighted by the proportion of debt to total assets, to the cost of equity funds weighted by the proportion of equity funds to total assets. The methodology requires estimates of the current market values of the firm's debt and equity and market rates for both sources of funds.

Subject to how cash flows are defined, alternative approaches can be taken to estimate WACC (see Appendix A). Provided cash flows are expressed as the levered cash flow available to service debt and equity, the post tax WACC for an entity (assuming that the tax deductibility of interest and the value of any imputation tax credits and taxation are included in the entity's cash flows) can then be calculated as follows:

$$WACC_{posttax} = R_{equity}\frac{E}{V} + R_{debt}\frac{D}{V}$$

where

R_{equity} = the return on equity (the cost of equity)

R_{debt} = the return on debt (the cost of debt)

V = the total market value of the firm

E = the market value of the equity

D = the market value of the debt

Alternatively, rather than incorporating them in the cash flows, tax and dividend imputation can be included directly in the WACC equation, that is:

$$WACC\ 1 = r_e\frac{(1-T_c)}{(1-T_c(1-g))}\frac{E}{(E+D)} + r_d(1-T_c)\frac{D}{(E+D)}$$

where:

T = corporate tax rate and

γ = assumed level of the value of imputation credits.

The major elements in applying a WACC model therefore include the determination of the cost of equity, the cost of debt, and the appropriate capital structure. The selection of an appropriate tax rate and the treatment of dividend imputation will also be important in determining the final WACC, either through direct inclusion in the WACC formula or through their inclusion in cash flows.

The cost of attracting and retaining equity funds is not directly observable and must be estimated using data from security markets. A number of alternative models have been developed to estimate the cost of equity funds, including the Capital Asset Pricing Model (CAPM), Dividend Growth Model, Price Earnings Ratio and Arbitrage Pricing Theory. The most common of these approaches, and the approach the Authority proposes to apply, is CAPM.

The central concept of CAPM is that of undiversifiable risk (known as beta (β)). Basically, the total risk of a business activity can be separated into two distinct classes of risk, being undiversifiable and diversifiable risk. Undiversifiable risk is that which affects the market as a whole and relates to the correlation between the riskiness of an entity compared to the market as a whole. It can be calculated by a linear regression based on historic data.

The remaining risk is known as diversifiable risk. This risk can be removed by holding the security as part of a well diversified portfolio of investments. CAPM assumes that investors will not be compensated for the risk they can cost effectively avoid. This avoidable risk arises because the fluctuations in an investor's return from holding a security can be ameliorated by holding that security as part of a portfolio of diversified investments. In other words, CAPM assumes that investors will only be compensated through the rate of return for the risk that cannot be avoided through diversification. However, this is not to say that diversifiable risk is irrelevant for valuation purposes. This is because the rate of return (based on undiversifiable risk) is then applied to the organisation's expected cash flows. These expected cash flows should reflect the diversifiable risks.

Accordingly, beta is a statistical assessment of the degree of undiversifiable risk associated with an asset or investment relative to a market portfolio, typically proxied by a stock market index. It assesses the systematic risk of the security, that is the risk that distinguishes it from the market as a whole. Since the beta of the market portfolio is 1, then all investments can be identified as being more or less risky than the market as a whole. For example, an enterprise with a beta of 1 has undiversifiable risk that is perfectly correlated with the expected return for the market as a whole. The further a beta departs from 1, the more its returns are expected to vary from those of the market as a whole. A higher beta is associated with a more risky investment and a low beta is regarded as less risky than the market as a whole. In the extreme, an investment that does not vary at all with the market has a beta of zero.

CAPM states that assets should be priced such that the expected return from them is equal to the risk free rate of return plus a premium for risk. The premium for risk is equal to the risk of the asset multiplied by the market risk premium, which in turn, is the difference between the return on the market as a whole and the risk free rate. The relevant measure of risk in the CAPM framework is beta. CAPM seeks to incorporate into the equity beta for the asset the undiversifiable risks related to that asset's industry and operations. Therefore, given the risk free rate, the equity beta of an asset and the overall market risk premium, the CAPM estimates the expected cost of equity funds for those assets.

However, an equity beta comprises an additional source of risk which arises from gearing. Because debt holders have senior claims to the entity's cash flows and assets, equity holders face an additional risk. This financial risk increases as the level of debt in the organisation's capital structure rises. CAPM assumes that a linear relationship exists between an entity's gearing and the financial risk associated with that gearing.

Therefore, there are two factors have been identified as key determinants of an entity's equity beta:

- asset risk arising from the entity's sensitivity to cash flow movements – relative to overall economic activity, where more cyclical cash flows are associated with higher betas; and

- financial risk arising from financial leverage – the ratio of debt to equity, where a higher level of debt implies a higher beta.

The CAPM is a forward looking model. For practical application, CAPM requires estimates of the risk free rate, the expected return on the portfolio, the expected return on the asset and the beta measure. CAPM is expressed as:

$$R_i = R_f + b_i\left[R_m - R_f\right]$$

where

R_i is the expected return on asset i

R_f is the risk free rate

R_m is the expected return on the market portfolio

$b_i = \dfrac{\mathrm{cov}\left(R_i, R_m\right)}{s_m} =$ Systematic risk of asset i

CAPM is a single period model which assumes that all investors have a common time horizon of unspecified length. It therefore has difficulty capturing the multi-period nature of most investments. As a result, it should be noted that the application of CAPM involves a certain degree of imprecision.

Summary of access arrangement proposals

Allgas and Envestra have both adopted the CAPM framework for the determination of the cost of equity, and have used a WACC approach for the calculation of the rate of return.

Other jurisdictions

All regulatory decisions in Australia over recent years have employed a WACC and CAPM framework as the method for determining the rate of return and cost of equity.

The Authority seeks comment on:

- **the proposed use of WACC for the calculation of the required rate of return; and**
- **the proposed use of CAPM for estimating the cost of equity for gas distribution entities.**

15.3 Issues in the selection of a WACC equation

Alternative methods exist to calculate WACC on either a pre tax or post tax basis and on either a nominal or real basis. These issues are discussed further in Appendix A. The appropriate WACC to use depends on the form of the cash flows being capitalised. Nominal (real) cash flows should be discounted with nominal (real) discount rates and post (pre) tax cash flows should be discounted with post (pre) tax discount rates. Each of the approaches should be equal in perpetuity but can have significant differences when measured in discrete time.

Pre or post tax WACC

The formulation of WACC and the definition of the cash flows used to calculate the revenue requirement should be consistent. An entity's cost of equity funds (as imputed using the CAPM) is usually expressed on a post tax (but before personal tax) basis.

The use of a pre tax rate of return is often advocated on the grounds that it avoids the need to explicitly add in to the 'cost of service' calculation an amount to compensate for tax obligations of the regulated business, and is therefore less intrusive, leaving the regulated entity to manage its own tax affairs. However, the tax calculation still needs to be undertaken to convert from the post tax rate of return indicated by CAPM benchmarks to the corresponding pre tax rate required for the regulatory framework. Therefore, as both approaches require tax liabilities to be properly assessed, there is little difference between a post tax and pre tax formulation of WACC in perpetuity.

In discrete time, arguments in favour of a post tax WACC include:

- the CAPM produces a post tax nominal return on equity and WACC. The conversion of this to a pre tax equivalent is complex and varies with regard to the techniques available for pre corporate tax or pre corporate and personal taxes;

- corporate taxes are a cost to the company like any other cost, and post tax measures of return are more relevant to investors. Adopting a post tax WACC requires cash flow modelling to explicitly address the question of the cash flow implications of taxation liabilities and an organisation's financial position. Accordingly, this approach is the most transparent and rigorous; and

- there is difficulty in estimating a long term effective tax rate as the tax system is not static. This may result in a perception of a risk that adjustments to the WACC would not adequately compensate for any changes in the tax system, or that errors could be introduced which result in under compensation in the rate of return.

Nominal or real WACC

The nominal and real rates of return are equivalent provided consistency is maintained with inflation adjustments, depreciation allowances and debt figures. Calculation of a nominal rather than a real WACC has the following advantages:

- depreciation in a nominal framework is transparent and there is no potential for confusion over the extent of recovery. However, this is not the case for a real framework, as depreciation allowances include adjustments for inflation so that accumulated depreciation may exceed the actual cost of the asset unless depreciation amounts are deflated;

- similarly, interest expenses and other non inflationary cash flows such as capped revenues or revenues from contracts containing no CPI adjustments require particular caution when converting from nominal to real. Errors in the conversion will result in discrepancies in the underlying cash flows;

- tax and balance sheet items such as debt and equity are all expressed in nominal terms. Consequently, the stock of debt must be deflated if modelling is to be undertaken in real terms;

- a nominal WACC is directly comparable with other financial benchmarks such as the nominal rate of return of other investments; and

- the nominal approach is the preferred approach of academics (see for example Davis 2000) and financial market participants.

The use of a real WACC has the following advantages:

- it is consistent with previous regulatory decisions in electricity and gas, and is therefore readily understandable and comparable; and

- there is no need to deflate the asset base, as is required in applying a nominal WACC.

Summary of access arrangement proposals

Allgas

Allgas has proposed a pre tax real WACC (equating to 7.75 per cent). Allgas notes that a real WACC applied to an indexed asset base provides a nominal revenue stream, and that an alternative would be to apply a nominal return to an unindexed asset base, which would require an additional adjustment to deflate the DORC asset base.

Allgas also supports a pre tax WACC on the grounds that the inclusion of tax allowances may subject consumers to price shocks, is overly intrusive, and is consistent with other regulatory decisions.

Envestra

Envestra has estimated a pre tax real WACC (calculated to be 7.75 per cent). Envestra notes that the conversion of the nominal post tax WACC calculation to a real pre tax figure can be done using two different methods, and that neither of these approaches provides precise results.

Other jurisdictions

The ACCC (1999) notes:

> "Given there is little to choose between post-tax and pre-tax formulations, the issue is fundamentally how best to assess tax liabilities – short or long term. There are a number of flaws associated with the use of a long term pre-tax WACC including:
>
> - front end loaded investor returns (where actual tax payments tend to be concentrated towards the end of the life of the assets. This arises because tax depreciation provisions (especially in the presence of accelerated depreciation) historically have allowed capital expenditures to be written off faster than the economic rate of depreciation. As a result businesses obtain returns well in excess of those intended under the regulatory framework in the early years but these are offset by lower than commercial returns later on.);
>
> - uncertainty over long term tax provisions; and
>
> - difficulties in estimating long term effective tax rates and applying them within a formula based approach."

The ACCC (2000a) also discussed a number of problems associated with converting a nominal post tax WACC to a real pre tax WACC, including that:

- conversion formulae have been shown to be significantly in error in ensuring the correct return on equity, although this problem can be overcome by modelling the expected cash flows and taxes over the life cycle of the asset portfolio; and

- the conversion process is unsuitable for assessing revenues over multiple periods where the business regime (principally taxes and inflation) is more likely to change, as it is extremely difficult to adjust the returns already allowed to take account of the new business regime, resulting in over or under recovery of costs.

The ACCC (2000a) noted that using a post tax nominal framework avoids these problems as the return on equity and estimated taxes payable allowances are separated in the Aggregate Annual Revenue Requirement formula. The tax payable can therefore be adjusted from period to period. The Commission cited support for such an approach from Professors Officer, Hathaway and Davis.

The ACCC also discussed a drawback of the post tax nominal framework, namely that customers of the network at different points in time will pay different charges for the same set of assets as a result of the assets' changing tax position rather than the underlying value of the service being provided. This is particularly the case where the firm takes advantage of tax concessions in the early years of the life of an asset, with tax liabilities increasing over time (the so-called S-bend debate). However, where a firm has a portfolio of assets, this effect is somewhat muted. In addition, the forthcoming removal of accelerated depreciation will mean the S-bend phenomena is progressively reduced.

In summary, the Commission considered that the post tax nominal framework, with several adjustments, produced an outcome which better met the objectives of the National Electricity Code than the pre tax real framework. The Commission adopted this approach in its final decision with respect to TransGrid's transmission revenues.

IPART (1999d) noted that there is considerable debate surrounding the use of pre tax real versus post tax nominal frameworks. As well as the standard approach to converting the post tax nominal to pre tax real, the Tribunal stated that there was a 'reverse' approach which involved first adjusting for inflation and then adjusting for tax. However, the Tribunal was of the view that none of the formulae available to convert the WACC to a pre tax real figure was sufficiently complex to account for all the relevant factors.

Given conventional market practice and the desire for consistency with the Code, IPART chose to use a pre tax real framework for its final decision with respect to electricity distribution networks, using several conversion formulae to achieve a pre tax real WACC range. However, the Tribunal foreshadowed its intention to consider the merits of moving to a post tax WACC in the context of its next determination.

The Authority seeks comment on whether the WACC should be calculated based on pre tax or post tax cash flows.

The Authority seeks comment on the merits of real versus nominal WACC calculations.

The estimation of a rate of return in the CAPM/WACC framework requires the estimation of a number of parameters. Conflicting views often exist as to what represents the most appropriate method for the measurement of each of these parameters. The sections following provide an outline of issues to be considered in the estimation of each of the parameters.

15.4 Issues in quantifying the risk free rate

The derivation of a return on equity under CAPM requires the estimation of a risk free rate. The risk free rate represents the rate of return on an asset with zero default risk.

There are two issues that need to be considered in the choice of an appropriate proxy for the risk free rate:

- what maturity period of bonds should be used to identify the interest rate; and
- the method of measurement of the risk free rate.

Choice of maturity

In terms of the maturity period, typically the debate centres on whether the maturity of the risk free rate should be set equal to, or as close as possible to, the life of the entity, or to the regulatory review period. For consistency with the CAPM framework, Officer (1981) states "the appropriate rate is that on a risk free security, eg. a government bond or note, of the same duration as the term of the investment". The ten year Commonwealth Government spot bond yield is a commonly used proxy for the risk free rate as it is a liquid instrument, provides the best reflection of the market risk free rate and can be identified using available market data. In Australia, it is conventional to use the redemption yield of ten year Commonwealth Government bonds as a proxy for the risk free rate.

The link between the longevity of the regulated assets and the planning/investment decision horizon of investors needs to be considered in determining the life of the risk free asset. As noted by the ORG (1998 p. 14):

> "In other relevant jurisdictions, there is recognition that amortisation of relevant assets must be over their full economic life which implies that investors must have an expectation that they will be compensated for making long term investments before they commit to the investment. Therefore, even though regulators may review investment returns at regular intervals, it would be a mistake to believe investors' planning horizons only extend to the next review. Models of expected returns and any regulation of those returns must reflect and take account of the investors' planning horizons. The reapplication of the prevailing long term rate every five years is sufficient to achieve this, as the owners of the project make their investment decision based on the life of the project, using the appropriate discount rate determined with reference to the prevailing yield curve."

The ORG also noted that some gas industry stakeholders had expressed concern that the use of short term rates will cause companies to concentrate their re-funding around each price review determination. It was argued by gas industry stakeholders in Victoria that the use of short term rates would cause periodic spikes in corporate bond rates due to the concentration of re-financing around the time of each re-set of the regulatory WACC.

It is also important to ensure that there is consistency between the choice of risk free rate and the assumed market risk premium. As noted by the ORG (1998), given that the available risk premium is expressed relative to the ten year bond rate, this rate is preferred as there is no additional benefit for calculation of the equity rate of return in using the five year bond rate. The ORG demonstrated that selection of the five year bond rate as the risk free rate would require the application of a market risk premium which measures the expected return on equities as a margin over the five year bond yields:

> "It has been suggested for example, that the choice of a shorter (or longer) rate will just lead to a higher (or lower) measured market risk premium, with no effect on the expected return for the well-diversified portfolio (and hence little effect on the required equity return). As the estimation of the market risk premium generally has used the current yield to maturity on Commonwealth Government securities of about ten years until maturity, this argument suggests that the risk free rate should reflect a security of a similar term."

The use of a long maturity for the risk free rate is also supported by there being no base level to which rates systematically return, for both short and long term nominal interest rates in Australia and international markets. The empirical literature strongly supports the concept of non-stationarity in nominal interest rates.

It has been argued that if the allowable WACC is revised at set intervals, the risk free rate should be set with reference to these periods. The primary arguments for using a rate linked to the regulatory review period initially arose from criticisms directed at the proposed use of the longer 30 year rate in the Victorian gas draft decision as opposed to a debate between the regulatory period versus the ten year rate.

Davis (1999) suggests that if the allowable WACC is to be revised periodically, then it is not necessary to use a long term rate for the risk free rate. Rather, Davis seeks to relate the prevailing interest rate to the length of the review period:

> "Given the anticipated life of the assets and the likely time pattern of the resulting cash flows, it would seem very difficult to sustain an argument for use of a risk free rate greater than 10 years. Use of a shorter maturity rate would not be inappropriate – particularly if there were to be regular regulatory pricing reviews."

Other arguments used to support the use of a rate linked to the regulatory period include that:

- rarely does initial debt funding for capital investments extend beyond ten to 15 years and in any event, it is likely that interest swaps would be re-set on a five yearly basis. However, interest rate swaps are available for a range of maturities from one to ten years; and

- even where a long term cost of capital is appropriate to the valuation of long-lived assets, it does not follow that it is appropriate for pricing decisions in the short run when the asset values are adjusted annually for inflation (thus removing a need for an inflation risk premium) and the allowable cost of capital can be revised at each review (to adjust for long term changes in market perceptions).

Method of measurement

In terms of the measurement of the risk free rate, it is possible to use either an 'on the day' rate or an average. The 'on the day' rate can be considered to be the theoretically correct rate to use, as it reflects all available information about previous rates. However, this rate may be subject to short term volatility, for example, due to central bank intervention or trading activity. To overcome this problem, some form of averaging may be used. For example:

- a short term average of the 'on the day' rate could be applied if the rate suffers a perturbation on the day of the decision; or

- an average rate reflecting trading over the past 20 to 40 trading days could be used. The process of averaging rather than using an 'on the day' rate smooths the day to day volatility in the observable interest rate. However, short time frames for the calculation of averages may be preferred on the grounds that they utilise the most recent (and therefore relevant) information.

Another alternative approach could calculate an implied nominal rate derived from a real rate of return plus a premium for expected inflation. However, this method is problematic in its calculation as both the real rate of return and the expected inflation cannot be observed directly and at best can only be proxied from other market data.

Summary of access arrangement proposals

<u>Allgas</u>

Allgas has applied a 40 day average of the ten year Commonwealth bond rate. Averaging has been applied on the basis that it:

- removes some of the potential volatility in rates;

- prevents investors establishing hedging/refinancing strategies on the basis of the timing of the regulatory reset; and

- produces a smoother price path.

The ten year rate has been preferred as it is consistent with investment in long lived assets, it is consistent with the measurement of the market risk premium, and as ten year bonds are less volatile than other bond rates. The rate nominated in the access arrangement is 6.2 per cent.

Envestra

Envestra has used the ten year bond rate consistent with the approach used in recent regulatory decisions and with the measurement of the market risk premium. A 20 working day average was applied to take account of potential volatility and the practical difficulty of taking a spot measurement. The rate nominated in the access arrangement is 6.2 per cent.

Other jurisdictions

The following table summarises the approaches adopted by different jurisdictions to determining the risk free rate.

Table 15.1: Risk free rate

Entity/Author	Industry	Benchmark bond	Estimation factor
ACCC (1998)	Gas transmission	10 year Commonwealth	12 month range
ACCC (2000b)	Gas transmission	10 year Commonwealth	40 day moving average
OffGAR (1999)	Gas transmission	10 year Commonwealth	20 day average
IPART (1999b)	Gas distribution	10 year Commonwealth	20 day average
IPART (1999f)	Gas distribution	10 year Commonwealth	20 day average
IPART (2000a)	Gas distribution	10 year Commonwealth	20 day average
ORG (1998b)	Gas distribution	10 year Commonwealth	2 month average
SAIPAR (2000a)	Gas distribution	10 year Commonwealth	On the day
ACCC (1999)	Electricity transmission	5 year Commonwealth	40 day moving average
ACCC (2000a)	Electricity transmission	10 year Commonwealth	40 day moving average
IPART (1999c)	Electricity distribution	10 year Commonwealth	20 day average
IPART (1999e)	Electricity distribution	10 year Commonwealth	20 day average
ORG (2000)	Electricity distribution	10 year inflation indexed	20 day average
OTTER (1999)	Electricity distribution	10 year Commonwealth	12 month rolling average

The Authority seeks comment on the appropriate risk free rate, including the appropriate choice of maturity and whether the rate should be an 'on the day' rate or based on some form of averaging.

15.5 Issues in determining the cost of debt

The cost of debt is the return that the entity's debt holders demand on new borrowings. Unlike the cost of equity, the cost of debt can normally be observed either directly or indirectly, as interest rates can be observed in financial markets. The cost of debt will vary depending on the default risk of the borrower, which, in turn, will be affected by the gearing of the company (high gearing means a high level of debt relative to cash flows and consequently a higher risk of default), short term volatility of cash flows and long term security of revenue.

The cost of debt may be calculated by reference to:

- a weighted average of the existing debt of the entity;
- the marginal rate at which a company can raise debt financing; or
- a margin over and above the risk free rate expressed in either nominal or real terms.

A further alternative is to use CAPM as a means of modelling debt, based on the risk free rate, the market rate and the debt beta. This can be expressed as follows:

$$R_d = R_f + b_d \left[R_m - R_f \right]$$

Where:

r_d = expected return on debt
r_f = risk free rate of return
β_d = debt beta
r_m = market rate of return.

The debt beta (β_d) reflects the financial risk borne by shareholders due to the entity's use of debt financing. Determination of debt betas is a matter of judgement. Arguably, given that the cost of debt is more readily observable than the cost of equity, a more appropriate approach is to use an alternative such as the margin above the risk free rate.

Summary of access arrangement proposals

Allgas

Allgas note that the Queensland Treasury Corporation has advised that a stand alone regulated gas network would be likely to have a credit rating of BBB+ to A+ given the level of gearing and the relative risk of the business. Based on these ratings, debt costs are estimated at 95 to 125 basis points above the risk free rate. Allgas has subsequently applied a margin above the risk free rate of 1.1 per cent, giving a pre tax cost of debt of 7.3 per cent.

Envestra

Envestra has estimated the pre tax nominal cost of debt by adding an appropriate debt risk margin to the risk free rate. Following an analysis of credit margins and swap margins, and consideration of the recent ORG decision in electricity distribution pricing, Envestra has determined that the appropriate debt margin is in the range of 140 to 160 basis points, equating to a cost of debt of between 7.6 per cent and 7.8 per cent.

Other jurisdictions

The following table outlines the cost of debt parameters used in regulatory decisions.

Table 15.2: Cost of debt margin

Entity/Author	Industry	Margin above the risk free rate (%)
ACCC (1998)	Gas transmission	1.2
ACCC (2000b)	Gas transmission	1.2
OffGAR (1999)	Gas transmission	2.0
IPART (1999b)	Gas distribution	1.2
IPART (1999f)	Gas distribution	0.9-1.1
IPART (2000a)	Gas distribution	0.9-1.1
ORG (1998b)	Gas distribution	1.2
OffGAR (2000a)	Gas distribution	1.2
ACCC (2000a)	Electricity transmission	1.0
IPART (1999c)	Electricity distribution	1.0
IPART (1999e)	Electricity distribution	0.8-1.0
ORG (2000)	Electricity distribution	1.2

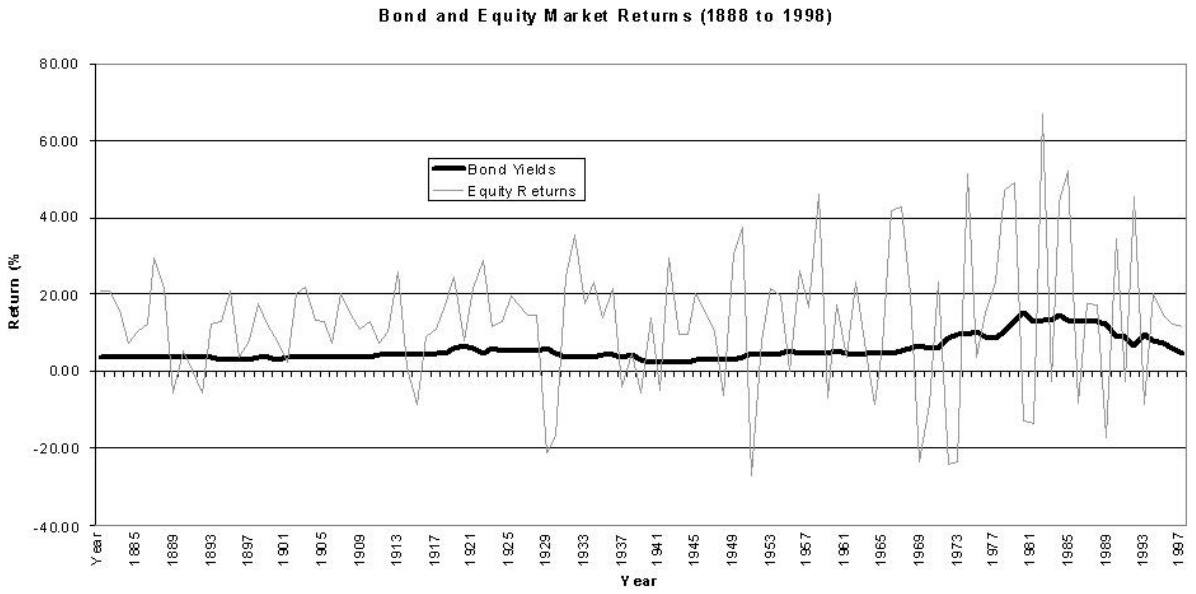
The Authority seeks comment on the appropriate approach to determining the cost of debt for distribution entities (for example, average cost of existing debt, marginal rate, margin above the risk free rate or CAPM).

15.6 Issues in quantifying the market risk premium

An important input to cost of capital calculations involves the use of the CAPM formula to assess the return on equity. The equity risk premium represents the reward that investors require to accept the uncertain outcomes associated with owning equity securities. As investors become more risk averse, they should demand a larger premium for shifting from the risk free asset and as the riskiness of the average risky investment increases, so should the premium. It is measured as the extra return that equity investors expect to achieve over the risk free rate.

The market risk premium is based on the difference between the return on the market as a whole and the risk free rate, both of which vary over time. As shown below in Figure 15.1, equity market returns are significantly more volatile than debt market returns. Both the equity and debt markets are influenced by short term business cycles and the fact that measures of risk premia are influenced by the measurement period.

Figure 15.1: Market returns



In theory, the CAPM requires that a forward looking market risk premium be based on a time frame corresponding to the period of the analysis (that is, the life of the asset). However, in practice this data does not exist. Alternative methods are suggested in the literature to estimate the market risk premium such as:

- surveys;
- the calculation of an implied risk premium based on a discounted dividend growth model or based on accounting data;
- consumption based modelling; and
- use of historical data.

Most regulators have preferred the use of an equity market risk premium proxied from historical data. Officer (1985) measured the market risk premium as the difference between the arithmetic nominal return to shares and the average annual yield on long dated government securities. During the period 1882 to 1987, Officer found the market risk premium to be at the average level of 7.94 per cent. Numerous studies have used Officer's approach to estimating the market risk premium.

Problems with the use of historical data to estimate the market risk premium include:

- the choice of proxies for the risk free rate and the return on the equity market. Typically studies will use the All Ordinaries Accumulation index as their proxy for the equity market and the ten year Commonwealth bond rate as proxy for the risk free rate;
- the choice of averaging period so as to obtain a representative level of the expected risk premium;

- structural breaks which may cause the average ex post returns for the market and the risk free rate to differ materially from the expectation period. A structural break occurs when time series data switches from one regime to another due to an exogenous shock. For example, the deregulation of Australian interest rates in 1979 or the floating of the Australian dollar in December 1983; and

- whether the averages should be arithmetic or geometric. Arithmetic means are consistent with the CAPM framework. However, the use of geometric means has been justified on the grounds that it takes into account continuous compounding. Geometric averages will be lower than arithmetic averages.

The findings of Australian academic studies and regulatory decisions suggest that the market risk premium ranges from 6 to 8 per cent with recent regulatory decisions favouring the lower range of 5 to 7 per cent. Most recent Australian studies show strong support for a market risk premium at 6 per cent. The Authority has examined the market risk premium in the period from 1970 to 1998 in detail to assess whether there was any significant difference in the market risk premium from the pre to post imputation periods. Empirical evidence suggests that there does appear to have been a sustained decline in the Australian equity market risk premium from 1987 relative to levels in the 1970s. However, this cannot be solely attributed to the introduction of dividend imputation in 1987. Other possible issues that need to be considered include:

- the decline in the risk free rate to the lowest levels since the late 1960s and the sustained decline in the level of inflation during the 1990s leading to decreased equity risk premiums;

- an increased use of financial leverage to engage in equity market transactions;

- changes in patterns of share ownership with increasing numbers of private shareholders following the recent floats by Telstra and AMP;

- increased influence of institutional investors on long term investment horizons thereby decreasing equity risk premiums;

- improved communications and technology and corporate disclosure requirements which have decreased information risks as information is now disseminated very quickly; and

- significant reductions in the level of corporate tax.

Summary of access arrangement proposals

Allgas

Allgas notes that the market risk premium cannot be measured with precise accuracy, and the market practitioners have generally applied a rate in the range of 5.0 to 7.0 per cent. Allgas has adopted a market risk premium of 6.0 per cent, based on the midpoint of this range and consistent with recent regulatory decisions.

Envestra

Envestra notes that there have been a number of studies into the market risk premium that estimate it to be in the range of 3.5 to 7.5 per cent. Envestra has selected a market risk premium in the range of 6.0 to 7.0 per cent, consistent with that used in recent regulatory decisions.

Other jurisdictions

In regulatory decisions, the measurement of the equity risk premium has usually been undertaken via the use of historical data as a proxy for both the market portfolio and for the risk free rate. Although a market risk premium is stated in a number of reports and academic articles, not all of these studies are clear in detailing which data was used in their calculations. This may lead to measurement errors in any comparisons between market risk premiums over time – especially given that short term interest rates are typically more volatile over time than long term rates.

The following table outlines market risk premia from various sources.

Table 15.3: Market risk premium

Entity/Author	Industry	Market risk premium (%)
ACCC (1998)	Gas transmission	6.0
ACCC (2000b)	Gas transmission	6.0
OffGAR (1999)	Gas transmission	6.0
Davis (1998)	Gas transmission and distribution	4.5-7.0
IPART (1999b)	Gas distribution	5.0-6.0
IPART (1999f)	Gas distribution	5.0-6.0
IPART (2000a)	Gas distribution	5.0-6.0
ORG (1998b)	Gas distribution	6.0
OffGAR (2000a)	Gas distribution	6.0
ACCC (2000a)	Electricity transmission	6.0
IPART (1999c)	Electricity distribution	5.0-6.0
IPART (1999e)	Electricity distribution	5.0-6.0
ORG (2000)	Electricity distribution	6.0
OTTER (1999)	Electricity distribution	6.0

The Authority seeks comment on the appropriate quantification of the market risk premium.

15.7 Issues in determining the capital structure

The term capital structure refers to the proportion of debt to total capital (that is, debt plus equity) employed by a business. In part, the capital structure will be important in determining the equity beta as an input to CAPM, as the proportion of debt will affect the risk profile of the entity. The higher the level of debt, the higher the equity beta will be and the higher the cost of equity.

However, capital structure is also a direct input into the WACC model. The optimum capital structure is that which minimises the WACC. However, it is generally accepted in finance theory that WACCs are approximately constant across a reasonable range of capital structures (where tax and dividend imputation are included in the cash flows).

The capital structure adopted for regulatory purposes may be that actually existing for the regulated entity, or some industry benchmark. Industry benchmarks are generally preferred on the grounds that this assumes an efficient capital structure, rather than adopting the existing capital structure, which may be inefficient.

Summary of access arrangement proposals

Allgas

Allgas assumes an industry standard gearing structure of 60 per cent, in line with previous regulatory decisions.

Envestra

Envestra proposes that a commercially appropriate long term average gearing level is 60 per cent, consistent with other regulatory decisions.

Other jurisdictions

The following table indicates gearing levels from other regulatory decisions.

Table 15.4: Capital structure

Entity/Author	Industry	Debt/Debt+Equity (%)
ACCC (1998)	Gas transmission	60
ACCC (2000b)	Gas transmission	60
OffGAR (1999)	Gas transmission	60
IPART (1999b)	Gas distribution	60
IPART (1999f)	Gas distribution	60
IPART (2000a)	Gas distribution	60
ORG (1998b)	Gas distribution	60
OffGAR (2000a)	Gas distribution	60
ACCC (2000a)	Electricity transmission	60
IPART (1999c)	Electricity distribution	60
IPART (1999e)	Electricity distribution	60
ORG (2000)	Electricity distribution	60
OTTER (1999)	Electricity distribution	50-70

The Authority seeks comment on the capital structures proposed by Allgas and Envestra.

15.8 Issues in determining equity and asset betas

As noted previously, equity betas used in calculating WACCs should reflect the perceived undiversifiable risk involved in that business. However, as noted by the Steering Committee on National Performance Monitoring of Government Trading Enterprises (1996):

> "The impact of beta estimates on the cost of capital is often overemphasised. Dividend imputation, changes in the risk free rate, assumptions regarding the size of the market risk premium and the rounding of targets, can all have a greater impact on the estimation of the cost of capital than a minor adjustment to the equity beta."

To assist in estimating beta (whether equity or asset), the following may be considered as reference points:

- overseas listed energy companies;
- comparable Australian companies listed on the Australian Stock Exchange (ASX), as well as listed companies that have a similar risk profile;
- views expressed by other Australian regulatory bodies; and
- an analysis of the volatility of each entity's cash flows.

The WACC relationship expresses the entity's cost of capital as the weighted average of the required return on its equity and debt. Because of the equivalence between the assets of the entity to a portfolio of the entity's equity and debt with respective weights of $\frac{E}{E+D}$ for equity and $\frac{D}{E+D}$ for debt, the return on assets can be expressed as follows:

$$R_a = R_e\left(\frac{E}{E+D}\right) + R_d\left(\frac{D}{E+D}\right)$$

By substituting CAPM for each of the returns (R_a, R_e and R_d) it is possible to express the above equation in terms of the relationship between the asset, debt and equity betas as follows:

$$b_a = b_e\left(\frac{E}{D+E}\right) + b_d\left(\frac{D}{D+E}\right)$$

where

b_a is the asset beta

b_e is the equity beta

b_d is the debt beta

An asset beta (β_a) represents the risk arising from the sensitivity of the operating cash flows generated by the assets of an entity compared with the market in general (that is, the market risk associated with an entity's assets). Asset betas vary with the volatility of free cash flows and are driven by sensitivity to the economy and operating leverage. Asset betas are not directly observable and therefore must be derived from equity betas.

The difference between an asset beta and an equity beta reflects the additional financial risk to a shareholder arising from the extent to which debt is used to finance the entity's assets.

The debt beta (β_d) reflects the financial risk borne by shareholders due to the entity's use of debt financing. The CAPM can be used to identify the debt beta as follows:

$$R_d = R_f + b_d\left[R_m - R_f\right]$$

Transformed:

$$b_d = \frac{R_d - R_f}{\left[R_m - R_f\right]}$$

It is obvious from the above that the beta of an entity's assets is equal to the betas of the entity's equity and debt weighted by the respective weights for equity and debt. Whilst equity and debt betas can be calculated via CAPM based methods, the asset beta can only be inferred via the above relationship.

For entities operating in the gas distribution industry, asset, debt and equity betas are estimated on the basis of businesses with comparable risk profiles, and irrespective of ownership. This facilitates calculation of the return on equity from the perspective of the marginal shareholder, and ensures that competitive neutrality is maintained.

To calculate an equity beta for the gas distribution entities in Queensland therefore requires:

- the selection of an appropriate asset beta based on an analysis of comparable asset betas;
- analysis of factors affecting the stability of cash flows; and
- the relevering of a selected asset beta to account for the preferred debt to equity ratio.

Appendix B discusses the equity, debt and asset betas in more detail and identifies issues in their calculation.

Summary of access arrangement proposals

Allgas

Allgas has applied an equity beta of 1.1, based on an asset beta of 0.5, a debt beta of 0.1 and a review of equity betas applied in recent regulatory decisions.

Envestra

Envestra notes that the Queensland gas market has greater non-diversifiable risk than those in Victoria, South Australia and New South Wales, due to reduced opportunities for growth, potential asset stranding and low market penetration. Taking these factors and recent regulatory decisions into account, an asset beta in the range of 0.5 to 0.55 has been selected. Given an estimated debt beta of 0.17, an equity beta of 0.98 to 1.11 was derived.

Other jurisdictions

The following table outlines asset and equity beta factors used in regulatory decisions.

Table 15.5: Asset and equity beta factors

Entity/Author	Industry	Asset beta	Equity beta
ACCC (1998)	Gas transmission	0.55	1.2
ACCC (2000b)	Gas transmission	0.6	1.5
OffGAR (1999)	Gas transmission	0.6	1.0
IPART (1999b)	Gas distribution	0.4-0.5	0.96-1.10
IPART (1999f)	Gas distribution	0.4-0.5	0.9-1.1
IPART (2000a)	Gas distribution	0.4-0.5	0.9-1.1
ORG (1998b)	Gas distribution	0.55	1.2
OffGAR (2000a)	Gas distribution	0.55	1.08
ACCC (2000a)	Electricity transmission	0.35-0.5	1.0 (range of 0.78-1.25)
IPART (1999c)	Electricity distribution	-	0.77-1.14
IPART (1999e)	Electricity distribution	0.35-0.5	0.78-1.14
ORG (2000)	Electricity distribution	0.5	0.95
OTTER (1999)	Electricity distribution	-	0.95

The Authority seeks comment on the appropriate quantification of the debt, asset and equity betas.

15.9 Issues in determining dividend imputation

Dividend imputation was introduced in Australia in July 1987. Under the imputation tax system, Australian resident taxpayers can claim a credit against the income tax payable by them on dividends received from Australian resident companies, to the extent of the Australian income tax that has been paid by those companies in respect of that dividend income. The dividend is said to be "franked" to the extent of the income tax that has been paid at the company level. For foreign investors, Australian tax credits cannot be used to reduce tax payable in their own countries. Hence the after tax return for a foreign investor receiving a franked dividend is lower than that for a domestic investor with an equivalent personal tax rate.

Hence, ignoring the timing impacts, an Australian resident taxpayer can be completely compensated for the incidence of company tax (but not personal tax).

Gamma is typically expressed as a number between zero and one, and represents the percentage of each dollar of dividends that is covered by an imputation credit. For example, a gamma of 0.80 implies an imputation credit of $0.80 per dollar of dividend paid.

Estimation of gamma

The valuation of imputation credits is determined by the following three key events in the life of imputation credits, which are discussed below:

- creation of imputation credits;
- distribution of imputation credits; and
- redemption or utilisation of imputation credits.

Creation of imputation credits

Franked dividends are those dividends paid out of profits on which Australian corporate tax has been levied and hence carry a credit for income tax paid by the company. The after tax return to an Australian resident taxpayer on a share with a franked dividend will be greater than the return on an equivalent share with a non-franked dividend. Dividends are able to be franked if the entity's income is earned in Australia and hence taxed at the corporate tax rate, and the income has been earned since the introduction of the imputation tax system on 1 July 1987. It should also be noted that both dividends and franking credits can be issued from retained earnings and not just from the current year's free cash flows.

Distribution of imputation credits

An entity's dividend policy affects the value of imputation credits. The smaller the payout ratio the less value imputation credits hold as the time value of imputation credits diminishes if a company defers payment of fully franked dividends. The introduction of dividend imputation in Australia has resulted in companies adopting generally higher payout ratios than during the pre-imputation period. Hathaway and Officer (1999) found that 80 per cent of company tax payments are distributed as imputation credits. The New Tax System (NTS) reverses some of the incentives for high dividend payout ratios that emerged from dividend imputation. This is because under the NTS capital gains attract a relatively low effective tax rate in a low inflation environment.

Redemption or utilisation of imputation credits

Each shareholder attaches a different value to imputation credits depending on his or her tax status. Investors who do not pay Australian income tax, such as Governments and foreign companies, gain no value from imputation credits whereas Australian resident taxpayers can gain up to 100 per cent benefit. However, it is generally assumed in regulatory decisions that the ability to utilise franking credits should be estimated by reference to the shareholder status of the marginal shareholder. As noted by Hathaway and Officer (1999), 60 per cent of the distributed franking credits are redeemed by taxable investors. In December 1999, the Commonwealth Government introduced legislation that has the effect of allowing the full offset of excess franking credits against income tax liability for Australian resident individuals and superannuation funds that previously were unable to claim the refunds. Subject to the other effects from the NTS, this of itself would tend to increase utilisation levels relative to historical benchmarks.

Consistent with the Hathaway and Officer study, when estimating the value of imputation credits from the perspective of the marginal shareholder, the following factors will need to be taken into consideration:

- all of the gas distributors' profits will be earned in Australia and are hence eligible to be franked;

- the 80 per cent market average of fully franked dividends identified by Hathaway and Officer appears relevant for the gas distributors given the anticipated low future capital expenditure requirements relative to other industries; and

- the range of utilisation of imputation credits in the market is likely to be around 60 per cent.

The Authority notes that while recent changes to capital gains tax may have the effect of altering these results, the Hathaway and Officer study remains the most current in terms of the distribution and utilisation of imputation credits.

The ACCC (1999, 2000a) argued that there was no well founded basis for discriminating in favour of one type of investor over another – such a process may distort pricing outcomes based on share ownership, and does not take into account other tax advantages or disadvantages that may be available to investors. As a result, the Commission supported the use of an industry average gamma. This view is also supported by OTTER (1999) and IPART (1999b, 1999c).

Summary of access arrangement proposals

Allgas

Allgas has adopted an Australian private ownership assumption in considering the value of imputation credits, and considers that the appropriate range for gamma given this assumption is 0.4 to 0.6. Allgas has adopted the midpoint of this range at 0.5, consistent with recent regulatory decisions.

Envestra

Envestra has adopted a value for gamma in the range 0.3 to 0.5, consistent with recent regulatory decisions.

Other jurisdictions

The following table summarises the gamma factors adopted in regulatory decisions taken by other jurisdictions.

Table 15.6: Gamma factor

Entity/Author	Industry	Gamma
ACCC (1998)	Gas transmission	0.5
ACCC (2000b)	Gas transmission	0.5
OffGAR (1999)	Gas transmission	0.5
IPART (1999b)	Gas distribution	0.3-0.5
IPART (1999f)	Gas distribution	0.3-0.5
IPART (2000a)	Gas distribution	0.3-0.5
ORG (1998b)	Gas distribution	0.5
OffGAR (2000a)	Gas distribution	0.5
ACCC (2000a)	Electricity transmission	0.5
IPART (1999c)	Electricity distribution	0.3-0.5
IPART (1999e)	Electricity distribution	0.3-0.5
ORG (2000)	Electricity distribution	0.5
OTTER (1999)	Electricity distribution	0.5

The Authority seeks comment on the appropriate valuation of imputation credits.

15.10 Issues in determining the tax rate

The cost of tax or "tax wedge" is the premium added to the post tax WACC, or amount included in the revenue requirement, to compensate for taxation liabilities associated with the regulated activities. There are broadly two alternatives to convert a post tax WACC to a pre tax WACC:

- "grossing up" the post tax WACC to account for the incidence of tax; or
- calculating explicitly, for each year, a cost of tax based upon benchmark assumptions either explicitly in the cash flows or via a "tax wedge" adjustment directly to the WACC.

Regardless of which method is selected, it is necessary to establish which of the following tax rates should be applied:

- the statutory rate; or
- the effective rate.

At 30 June 2000 the statutory company tax rate was 36 per cent. Following amendments in December 1999, the statutory tax rate for the 2000-01 tax year will be 34 per cent and 30 per cent thereafter. In 1999, Commonwealth Government legislation was passed which had the impact of removing accelerated depreciation[1] for plant acquired after 21 September 1999 and replacing it with effective life depreciation.[2]

The effective tax rate adjusts the statutory rate for both timing and permanent differences of tax deductions and is recorded as the ratio of the tax expense to the accounting operating profit before tax. Because of accelerated depreciation and diminishing value depreciation, taxpayers may claim a tax deduction for depreciation that is in excess of the depreciation actually incurred, thus bringing forward the tax deductions and increasing the value of these tax benefits in net present value terms. Thus, allowing for the time value of money, the effective tax rate for a major infrastructure provider may be below the statutory rate. In practice, if a relatively high value of imputation credits (gamma) is adopted, then the issue of the tax rate (whether statutory or effective) assumes considerably less significance.

However, it is very difficult to estimate the effective tax rate over the life of assets which span from 25 to 100 years. This is because such estimates are dependent on assumptions in respect of maintenance of the effective tax regime, inflation and the depreciable value of assets for tax purposes. Altering access prices for changes in effective tax rates may result in an undesirable increase in price volatility. This supports the use of the statutory tax rate rather than the lower effective tax rate.

An alternative approach to the treatment of gas distributors' tax liabilities is to use a post tax WACC for the determination of the revenue requirement by including forecast tax payments in the cash flows. The ORG prefers to use this approach but expresses their tax wedge in percentage terms, as the ratio of the benchmark cost of tax relative to the regulatory asset value.

Summary of access arrangement proposals

Allgas

Allgas has adopted a tax rate of 30 per cent, consistent with long term expectations of the statutory rate.

Envestra

Envestra has adopted the average statutory tax rate over the access arrangement period of 30 per cent.

Other jurisdictions

As outlined in the following table, tax rates in regulatory determinations in Australia have ranged from 30 per cent to 36 per cent.

[1] Accelerated depreciation (AD) refers to the situation where the cost of an asset is depreciated over a shorter period than the asset's effective life. It is achieved through the allowance of deductions for declines in the value of an asset at higher rates than are expected to occur in practice. This has the impact of providing the taxpayer with a cash flow advantage. AD has the impact of bringing forward depreciation deductions resulting in tax being deferred during the early years of an asset's useful life and increases tax in later years. AD provided significant benefits to capital intensive industries such as mining and manufacturing, whilst being of little benefit to service industries such as finance, tourism or retailing.

[2] Effective life depreciation involves the depreciation of the wasting asset over the effective life of the asset. A wasting asset can be defined as those assets, which at the time they are acquired or created, can be reasonably expected to decline in value over time.

Table 15.7: Tax rates

Entity/Author	Industry	Tax Rate (%)
ACCC (1998)	Gas transmission	36
ACCC (2000b)	Gas transmission	30
OffGAR (1999)	Gas transmission	36
IPART (1999b)	Gas distribution	36
IPART (1999f)	Gas distribution	36
IPART (2000a)	Gas distribution	30
ORG (1998b)	Gas distribution	36
OffGAR (2000a)	Gas distribution	31.4
ACCC (2000a)	Electricity transmission	30
IPART (1999c)	Electricity distribution	36
IPART (1999e)	Electricity distribution	30-36
OTTER (1999)	Electricity distribution	36

The Authority seeks comment on the appropriate tax rate to be applied to gas distribution entities.

The Authority also seeks comment on any other issues which should be considered in the context of the allowed rate of return.

16. NON CAPITAL COSTS

Non capital costs are those costs associated with the operation and maintenance of gas distribution networks. Unaccounted for gas (UAG) is also an item which some distributors have proposed as a non capital cost. UAG is generally considered to be the gas that is lost from the network primarily due to leakage and metering errors.

16.1 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. Provision is made for current or forecast non capital costs to be recovered, providing such costs would be those incurred by a prudent service provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost in delivering the reference service. The Code also requires that any forecasts used in setting reference tariffs are best estimates arrived at on a reasonable basis.

16.2 Issues in determining non capital costs

Non capital costs can be divided into the activities of marketing; overheads; and operating and maintenance. Marketing costs should normally be confined to those that maintain and promote safe and efficient use of the network. Overheads incorporate administration and general costs. Operational costs constitute the bulk of non capital costs due to the fact they contain, among other things, wages and salaries directly attributable to the repair and upkeep of the network and the cost of materials and supplies.

In considering the prudence of non capital expenditure and the efficiency of a network operator, a regulator can benchmark against performance indicators in relation to other distributors as well as indicators for the firm itself over time. Some of the more common operational performance indicators include non capital expenditure per kilometre of mains, per customer and per GJ of gas delivered. The role of such indicators is to provide guidance as to whether estimates of such costs can be reasonably justified and if there is scope for further cost reductions and/or improvements in efficiency in the future. Such improvements are generally sought to be achieved through an incentive mechanism (for example, CPI-X – see Chapter 18: *Incentive Mechanisms* for a discussion on these issues).

While this information will assist the regulator in making a judgement in approving non capital costs to be recovered through total revenue and how these costs might be expected to fall in real terms over time, these indicators cannot be considered in isolation given they are subject to influences both internal (such as accounting policies) and external (such as climate) to the firm.

The level of non capital expenditure will also 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.

The treatment of unaccounted for gas (UAG) as part of non capital costs has not been consistent across gas distribution networks in Australia. It could be argued that its inclusion as an operating cost provides an incentive for a network to reduce costs by reducing UAG. It could also be argued that exclusion from operating costs creates even stronger incentive for reductions, as distributors are then not able to recoup such costs through reference tariffs. Several of the Australian network owners have proposed a pre-determined UAG allowance such that if actual UAG exceeds this specified level over a given period of time, users are compensated for the difference and vice versa.

Summary of access arrangement proposals

Allgas

Allgas has proposed non capital costs in the categories of administration, public awareness and marketing and operations and maintenance. Table 16.1 outlines the forecast operating and maintenance costs proposed by Allgas, which show real reductions over the access arrangement period.

Table 16.1: Allgas non capital costs ($m, nominal)

Costs	99/00	00/01	01/02	02/03	03/04	04/05
Network operation and maintenance	6.448	5.700	5.542	5.476	5.590	5.777
Network marketing	0	0.203	0.203	0.203	0.203	0.203
Administration	1.180	1.400	1.400	1.400	1.400	1.400
Total non capital costs	7.628	7.303	7.145	7.079	7.193	7.380

The passthrough of costs relating to full retail contestability, environmental works and gas balancing is also being sought. While Allgas considers gas balancing costs to be effectively zero at present, this is also an area which could be affected by the introduction of contestability.

Unaccounted for gas has been listed as a separate item. As Table 16.2 shows, UAG levels are forecast to fall significantly over the initial access arrangement period as more of the network is replaced.

Table 16.2: Allgas forecast levels of UAG and forecast UAG costs

	99/00	00/01	01/02	02/03	03/04	04/05
UAG (TJ)	520	523	471	430	397	370
UAG Cost ($m)	2.356	2.369	2.189	2.047	1.937	1.850

Envestra

Envestra has grouped non capital costs into the areas of administration and general, network marketing and operational costs, as set out in Table 16.3. Overall, these are forecast to fall in real terms over the access arrangement period as a result of cost reductions and improvements in labour productivity.

Table 16.3: Envestra non capital costs ($m, nominal)

	00/01	01/02	02/03	03/04	04/05	05/06
Administration and general	1.0	1.0	1.0	1.0	1.0	1.1
Operating and maintenance costs	11.3	11.2	11.0	10.9	10.8	11.0
Network marketing	1.3	1.3	1.3	1.4	1.4	1.4
Total non capital costs	13.6	13.5	13.4	13.3	13.3	13.5

Note: Envestra also provides unregulated services to a small number of sites, the costs of which are not included in the figures above.

It should be noted that the cost of UAG (described as SUG in Envestra's access arrangement) has been incorporated under the operational component of non capital costs in Table 16.3. Figures for actual and forecast SUG are contained in Table 16.4 below.

Table 16.4: Envestra forecast levels of UAG (SUG)

	99/00	00/01	01/02	02/03	03/04	04/05	05/06
SUG (TJ)	594	577	550	514	481	445	410

Other jurisdictions

Table 16.5 provides a summary of proposed non capital costs under the three categories for various gas distribution networks across the country. The table shows that, with the exception of AGL[3], operational costs comprise by far the most significant component of non capital costs, ranging between 60 and 84 per cent. Marketing costs range between 2 and 18 per cent, while overheads account for between 7 and 32 per cent. The table also shows what proportion of proposed revenue the networks expect to attribute to non capital costs. While there may be a degree of variation in the proportions taken up by the individual components of non capital costs, as a percentage of revenue the networks look fairly similar, averaging around 30 per cent.

[3] A very large portion of AGL's marketing expenditure comprises retailer rebates.

Table 16.5: Non capital cost components and percentage of revenue

Network	% of total non capital costs			Total non capital costs as a % of revenue
	Overheads	Marketing	O & M	
Albury Gas Company (c 99)	14.3	2.5	78.2	30.1
AGL(f 98)	34.1	30.8	35.2	37.1
GSN(f 99)	13.0	8.1	73.4	31.5
Multinet(c 99)	17.6	2.1	80.4	25.5
Stratus(c 99)	27.8	12.7	59.9	28.7
Westar(c 99)	32.1	5.9	62.0	28.1
Envestra (SA)(f 99)	19.9	18.0	62.1	27.2
AlintaGas(c 00)	12.5	3.9	83.7	33.3
Allgas(f 00)	**19.2**	**2.8**	**78.0**	**24.7**
Envestra (Qld)(f 00)	**7.4**	**9.6**	**83.0**	**37.9**

Note: Percentages are based on figures obtained primarily from access arrangement information, which is not necessarily consistent across networks. Care should be taken in interpreting these figures as differences exist due to rounding, calendar year versus financial year, the actual year under consideration, and the fact that not all networks explicitly defined non capital costs into these categories. With the exception of Envestra (Qld), figures are exclusive of UAG.

c – calender year; f – financial year.

IPART (1999d, 1999g) has been conscious of separating costs not strictly related to network activities, particularly those more closely associated with downstream retailing. In this regard marketing costs have emerged as one area of contention. For two of the three gas distribution networks in New South Wales, UAG is treated as a retail rather than a network cost. In addition, where comparison of performance indicators with other networks has shown there to be scope for further efficiency gains in O & M costs, the Tribunal has required the owners to pursue them.

The ORG (1998b) commissioned Ewbank Preece to conduct a technical review of Multinet, Westar and Stratus. In line with the review's findings, the ORG accepted the proposed non capital costs of the three distributors as meeting the requirements of the Code, aside from inflation rate assumptions. The ORG also made determinations on two greenfields distribution networks where competitive tender determined a number of items. In ORG (1999b) the Office emphasised its application of the prudent operator test to actual non capital costs when calculating the level of under-recovery of revenue in the initial years of the access arrangement. In ORG (1999c) the owner expressed concern over the Office's possible rejection of network utilisation expenditure, and has sought annual reviews of forthcoming non capital expenditure. While this has been denied, the Office is prepared to provide comments on a non-prejudicial basis.

OffGAR (2000a) did not consider the non capital costs pertaining to AlintaGas to be sufficiently justified, nor adequate allowance made for reasonable efficiency gains and cost reductions, particularly in respect of maintenance as well as the levels and costs of UAG. Irrespective of this, OffGAR found that non capital costs for the network were still comparable with other distribution systems and accepted the forecast non capital costs, providing allowance is made for an accelerated improvement in operating and maintenance costs and a reduction in the proposed level of UAG over the period of the access arrangement.

Considerable negative public comment was made on Envestra's forecast non capital costs for its South Australian network, particularly in regard to systems use gas (SUG) and marketing. Generally speaking, SUG was considered too high and marketing costs excessive and inappropriate. As a result, SAIPAR (2000a) has required further reductions in SUG over the period of the access arrangement and marketing costs have been approved subject to a number of conditions mainly relating to the provision of annual, detailed expenditure reports. Overall, SAIPAR has imposed further efficiency gains for all non capital costs excluding SUG, licence fees and contaminated sites.

The Authority seeks comment on whether the operating and maintenance costs of the Queensland distribution networks constitute reasonable estimates.

17. ALLOCATION OF REVENUE AND COSTS

The appropriate allocation of revenue and costs is an important element in capturing the benefits from competition and is one of the objectives of regulation in industries without effective competition. To be efficient, the allocation of costs should not distort either production or consumption decisions. To achieve this, the access arrangement needs to detail how costs will be allocated and how tariffs will be structured.

17.1 Code requirements

The Code (section 8.38) requires that, to the maximum extent that is commercially and technically reasonable, a reference tariff for a reference service should be designed to recover all costs directly attributable to that service, as well as a reasonable share of joint costs. The reference tariff principles provide a guide as to how the total revenue requirement might be met between reference services and by users of each reference service. These principles essentially require that the charge paid by any user of a reference service be cost reflective, although substantial flexibility is provided.

An exception to the allocation rule is the case of prudent discounts (section 8.43). Where a user is paying less than the reference tariff, and such a discount is 'prudent', the QCA has the discretion (when reference tariffs are set initially or reviewed) to permit the service provider to recover some or all of that shortfall in revenue by raising reference tariffs to other users. (If the discount is prudent, the reference tariff for that service for all users would still be lower than if the recipient of the discount was no longer a network customer.)

17.2 Issues in determining the allocation of revenue

The Code's pricing principles refer to the portion of revenue that reference tariffs are designed to recover from particular services, and to the amount of revenue that is recovered from each user of a reference service. These principles raise two issues, whether:

- the revenue received from each customer, customer class and service is appropriate (cost allocation); and
- the design of the reference tariffs is appropriate and provides a sound basis for charging for the use of the system (tariff structure).

Cost allocation

In a perfectly competitive market, a user of a good or service would face only those costs that the provider incurs in providing that good or service; that is, marginal cost. Charging one user more than that cost would expose the service provider to being undercut by a competitor.

However, as detailed previously in this issues paper, marginal cost pricing is not possible in industries with natural monopoly characteristics, such as the gas distribution industry, because:

- a high proportion of costs cannot be attributed to individual users of the system, making it difficult to apportion costs accurately between different users; and
- if all users paid marginal cost, the service provider would not cover total costs, rendering the service unsustainable.

Because of these characteristics, service providers need to allocate fixed costs between users and between services by some method.

The intention of the requirements in the Code is to ensure the method used to allocate costs does not reduce economic efficiency. Consistent with that intention is the recognition that there are costs in identifying users, on the basis of characteristics of demand and use, which increase with the level of detail required. At some point, an increase in the degree of accuracy with which costs can be attributed to particular users is not justified by the improvement in efficiency.

One means of characterising classes of users is on the scale of gas used, such as industrial, commercial and domestic customers. Another means is a regional distinction, with customers in different parts of the network charged on the basis of the costs of supplying that part of the network. Any such method of aggregating classes of customers will involve a degree of arbitrary judgement (in addition to the arbitrary judgements required under any method to allocate fixed costs). The question is whether the costs to particular users flowing from this exceed the benefits of lower administration costs.

Cross subsidy

Prices to certain customers that do not reflect the costs of their consumption are inefficient, because neither service providers nor users are taking into account the full cost of the resources used in providing the service. Where total returns are regulated, prices that do not reflect costs can result in one set of customers subsidising others, or cross subsidy.

In general, a cross subsidy would exist if the prices paid by one customer or group of customers were higher than they would otherwise have been if another customer or group of customers did not use the system. With total returns subject to regulation, this implies one or more customers are paying prices less than the incremental cost of providing services.

At the most simple level, where there are two customers, for a cross subsidy to exist:

- one customer pays more than the cost if that customer were the only one receiving the services (stand alone cost); and

- the other customer pays a price less than the incremental cost of providing those services.

Where there are more than two customers, stand alone costs may be shared between a number of customers. That is, for a cross subsidy to exist, it is not necessary for single customers to pay prices higher than stand alone cost; only that, as a group, some customers are paying prices higher than would be necessary to provide services only to that group. In that situation, a cross subsidy could exist at a level of prices significantly lower than the cost of providing the service to an individual user on a stand alone basis.

Prices may vary between a standard or average price for all consumers, or be set on some basis such as ability to pay, which implies different prices for different customers. As long as this does not constitute a cross subsidy, this need not necessarily concern a regulator. Price discrimination, that is charging some customers more than others, on the basis of their willingness to pay, can be economically efficient, in that it allows optimal use of the infrastructure. It also could be said to be fair (between customers), as customers paying the higher price would not be paying more than they would if customers paying the lower price did not use the network.

However, where customers are competing in downstream markets, price discrimination is likely to provide an advantage to some customers at the expense of others, which is neither fair nor efficient. The Code requires the QCA to have regard to possible downstream effects of pricing policies.

Should any cross subsidies exist, they will need to be removed to arrive at cost reflective prices. One option to achieve this would be to adjust prices immediately, so that prices to subsidised customers would rise and prices for other customers would fall. Another option would involve some period of phased adjustment. This would spread the price increases to subsidised consumers over a longer period. However, it would also prolong the inefficient pricing of gas distribution and price reductions for other customers would be similarly delayed.

Prudent discounts

Once tariffs are set, the Code recognises the need for service providers to reduce prices to those customers able to use other service providers (that is, bypass the system) – so called prudent discounts. The Authority notes the Queensland Government is party to the *Natural Gas Pipelines Access Agreement* between the Commonwealth and all States and Territories, which provides that bypass to contestable customers should be allowed if the operator has the necessary operating licences.

Service providers wishing to apply a prudent discount must gain the approval of the regulator to recoup forgone revenue from other users of the network. As noted above:

- there are limits on the ability of the service provider to shift revenue between users; and
- price discrimination between end use customers who are competing in the same downstream market is likely to be neither fair nor efficient.

The Authority is interested in receiving views on possible circumstances where the need to apply prudent discounts could occur and suggestions as to what guidelines should be in place to ensure downstream markets are not affected by the application of prudent discounts.

Summary of access arrangement proposals

Cost allocation

Allgas' access arrangement information states it allocates costs to consumers based on stand alone costs for the large customer group and incremental costs to the small customer group. These costs are derived on a zonal system, reflecting distance from the transmission pipeline. The access arrangement information states the alternative approach, average cost pricing, is not feasible because of the incentive this provides some large customers to bypass the distribution system.

Envestra allocates costs on a stand alone basis to demand (large) customers and an incremental cost basis to volume (small) customers. The access arrangement information states that stand alone cost is determined with reference to a 'notional network', based on the optimum pipeline route to most efficiently connect natural groupings (clusters) of demand delivery routes. There appear to be two such clusters, Brisbane and Northern.

Cross subsidy

Allgas proposes to remove any cross subsidies progressively, to minimise price shocks to consumers. This will be accomplished by reducing prices to large customers relatively quickly, with price adjustments within the small customer class over the term of the access arrangement.

For the small customer class, Allgas proposes annual price adjustments of CPI minus 0.5% for the first two years of the access arrangement, and CPI minus 2.5% thereafter for the duration of the access arrangement. While overall revenue for this customer class will reduce by these amounts, prices for individual customers within the class may vary. Allgas proposes that the maximum annual price increase for any individual end user will be CPI plus 5%.

For the large customer class, Allgas proposes annual price adjustments of CPI minus 9.4% for the first two years of the access arrangement, and CPI minus 5.0% thereafter for the duration of the access arrangement. The maximum annual price increase for any individual end user will be CPI plus 5%.

Envestra's access arrangement information states low prices for haulage (small) customers are reflected in under-recovery of revenue by Envestra. Envestra proposes to move to cost reflective pricing by 2009-10.

For the small or volume customer class, Envestra proposes annual price adjustments of CPI plus 1.0% for the duration of the access arrangement. For the large or demand customer class, Envestra proposes annual price adjustments of CPI minus 0.1% for the access arrangement period. No side constraints on prices for individual end users are proposed.

Other jurisdictions

Cost allocation

In New South Wales, AGL adopted stand alone costing for industrial (contract) users and incremental cost for domestic (tariff) users. The regulator (IPART 1999d) required fully distributed costs for both operational expenditure and capital costs.

In South Australia, Envestra adopted stand alone costing for industrial (demand) users (that is, prime user costing) and incremental cost to commercial and domestic (tariff) users. This was accepted by the regulator (SAIPAR 2000a).

In Western Australia, CMS Gas Transmission (Parmelia) adopted a differential approach, with existing contracts charged on their projected share of revenue, new contracts charged on their projected share of volume and a discount of 10 per cent for interruptible services. This approach was not accepted by the regulator (OffGAR 1999), which required all users, including existing users, to contribute to costs on the basis of their projected share of volume and any price discount for interruptible services to be justified by cost data.

In Victoria, Multinet, Westar and Stratus adopted a cost of service model for each customer class (defined by size and geography), within bounds of incremental and stand alone costs. The regulator (ORG 1998b) accepted this approach.

Cross subsidy

Most service providers and regulators have dealt with cross subsidy implicitly, by way of adjustments to tariffs over time. (See the section of this issues paper dealing with the Form of Regulation.) This generally was referred to as 'tariff re-balancing'. As noted above, regulators generally have accepted the need to undertake this exercise, although no regulator has allowed real prices to rise, the re-balancing being accomplished by small nominal price increases over time.

The Authority seeks comment on:

- **what means should be used to allocate costs between users and between services;**
- **whether sufficient information is provided with the access arrangements to provide confidence in the cost allocation proposed by the distributors;**
- **whether a cross subsidy currently exists between different groups of users; and**
- **what approach should be taken to remove any cross subsidy.**

Tariff structure

An efficient tariff structure in gas distribution would distort decisions by gas distributors and retailers as little as possible. To achieve this, prices for marginal use of the network should reflect as closely as possible the marginal costs of providing that service. This can be achieved by a multi-part tariff, with the charge for access separate to that for actual use of the system. That is, the user would pay for the right to a given amount of access, or a 'reservation charge', with actual use of the system charged for on the basis of the cost to the service provider of providing each unit used. In total, the reservation charges paid by all users would cover the service provider's fixed costs, leaving both service providers and users facing the marginal cost for each marginal unit of output.

The effects of a multi-part tariff regime between distributors and retailers on final demand for gas would be indirect. However, the structure of tariffs may affect retailers' operations, such as the way retailers package their product or operate in the gas market to secure supply.

Summary of access arrangement proposals

Allgas

Allgas has proposed, for retailers supplying both small and large customers, a multi-part tariff, comprising:

- a base charge, for access to the network;
- an additional capacity charge; and
- a sliding scale of charges reflecting actual gas consumption (with higher volumes attracting a lower per-unit charge).

Different tariff schedules apply for small customers, and for large customers in each geographic region of the system (that is, Brisbane, the Gold Coast, Toowoomba and Oakey). In addition, for large customers, different tariffs apply to different regional zones within each geographic area.

Envestra

Envestra has proposed:

- for demand (large) customers, a $/GJ charge on a declining block basis. That is, as use increases, the cost per GJ reduces; and
- for volume (small) customers, the tariff will be composed of a daily supply charge and declining blocks based on the quantity of gas delivered.

Other jurisdictions

Multi-part tariffs are a standard feature across jurisdictions in Australia.

In Victoria, Multinet, Westar and Stratus proposed two sets of tariffs, with retailers' charges for supply to domestic customers based on volume of gas consumed, and charges for supply to other customers based on expected use relative to expected peak demand. The ORG (1998b) reserved judgement on the proposed tariff structure for domestic customers, but was of the view it was inappropriate to require changes to the proposed tariff regime, as these were associated with regulation of retail tariffs by the Victorian Government. With regard to other customers, the ORG required changes so that charges reflect actual contribution to network congestion.

The Authority seeks comments on the structure of tariffs for gas distribution in Queensland.

18. INCENTIVE MECHANISMS

For any access regime, a system of rewards and penalties will be important to encourage firms to improve performance. In gas distribution, such mechanisms are aimed at increasing use of the infrastructure and promoting investment and growth in the market, which should result in both lower costs and higher returns. A further consideration is the degree to which such benefits are to be passed on to consumers, and timing of the passing on of such benefits.

Essentially, incentive mechanisms are designed to provide regulated entities with:

- the incentive to reduce costs from their current levels by, for example, incorporating a CPI-X framework which requires reductions in costs just to keep their net returns constant; and

- the incentive to outperform the benchmark, by allowing the entity to retain all or some of the outperformance for a period of time.

The objective is to try to provide a business that exhibits monopoly characteristics with the impetus to respond to positive efficiency incentives (and avoid disincentives) that are more often found in competitive markets, thus benefiting both themselves and their customers.

18.1 Code requirements

Sections 8.44 to 8.46 of the Code provide for the use of incentive mechanisms.

The Code requires that, wherever appropriate, a reference tariff policy contain mechanisms which permit the service provider to retain all or part of any returns in excess of those expected at the beginning of the access arrangement period, particularly where those returns are attributable to the efforts of the service provider.

Under the Code, incentive mechanisms are designed to encourage a service provider to increase sales, minimise costs, develop new services, restrict expenditure on new facilities and non capital costs to that which is prudent, and enable users to share in the benefits which arise as a result of increased efficiency, innovation and the volume of sales. Such mechanisms may include, but are not limited to, specifying the reference tariff to apply each year, specifying a target revenue which, if surpassed, a portion may be retained by the service provider, or some form of rebate mechanism.

18.2 Issues in determining incentive mechanisms

The X-factor

The first issue in addressing incentive mechanisms is setting the required reduction in non capital costs (that is, the X-factor). An X-factor can be established by considering the operational history of a firm directly (linking reductions in costs to the firm's past performance) or alternatively, with reference to industry or economy-wide benchmarks that are independent of an individual firm's costs of production.[4]

The first approach relies heavily on the provision of detailed cost information by the firm, both current and forecast. This approach allows for consideration of firm-specific issues such as the potential for cost reductions without adversely affecting service quality, the opportunity for growth in the market and the ability of the firm to finance operations. However, there is potential for information gaming and the absence of independent benchmarks means that expected improvements in performance are not necessarily related to best practice standards.

[4] This section draws on the analysis made by IPART (1999), *Incentives and Principles for Regulation*, DP-32.

The use of broader benchmarks for efficiency and productivity as an input to the CPI-X process has generally been preferred for these reasons. In this case, the X-factor is tied to movements in productivity for the industry relative to the economy. While this type of approach is said to increase the transparency and predicability of the regulatory process, there may be some question as to the relevance of the performance benchmarks that result from it given that each network will have its own unique characteristics.

Sharing of benefits

Secondly, consideration must be given to the extent to which a firm retains any out-performance of the X-factor, the period over which gains are to be shared, and the profile of the sharing arrangements. Generally speaking, the shorter the period of retention the less incentive firms have to out-perform.

Possible approaches to the sharing of benefits between service providers and users include:

- a glide path – whereby gains are passed on to end users either partially or entirely over time; and

- one-off reductions – whereby gains in excess of the X-factor in the previous period are passed directly on to consumers upon commencement of the next price review.

The gains achieved by a firm over a regulatory period are the combined effect of actions both within and beyond a firm's control. In practice, making this distinction is often difficult. By limiting the retention of gains to those considered controllable, managers should be encouraged to continually seek such efficiency gains in the future. Rewarding firms for windfall benefits could potentially disadvantage customers and have adverse effects on efficiency.

With any form of benefit sharing mechanism, perhaps the key issue is to strike a balance between timing the flow of benefits to end users and maintaining sufficient incentives for firms to continue to pursue further efficiency gains.

Cost passthrough

Cost passthrough allows a firm to increase (or decrease) its price or revenue cap in response to a corresponding increase (or decrease) in an input cost that is typically beyond the firm's control and is readily observable. These might include changes in taxes, charges, levies, imposts and fees. In allowing for cost passthrough the firm is able to shift the risk associated with a specific input cost on to the customer. This may be considered a way of minimising a firm's exposure to windfall gains or losses. This issue is discussed further in the section on the Form of Regulation.

Summary of access arrangement proposals

Allgas

Allgas has proposed progressive reductions in operating and maintenance costs and UAG levels (see Chapter 16: *Non Capital Costs*). Table 18.1 indicates the percentage change in these costs proposed over the access arrangement period.

Table 18.1: Allgas operating and maintenance and UAG costs

	99/00	00/01	01/02	02/03	03/04	04/05
Total operating and maintenance costs ($m)	7.6	7.2	7.1	7.0	7.1	7.3
Change in costs from previous year ($m)	N/A	-0.4	-0.2	-0.1	0.1	0.2
Change from previous year (%)	*N/A*	*-5.1*	*-2.2*	*-1.0*	*1.6*	*2.6*
Total UAG costs ($m)	2.4	2.4	2.2	2.1	1.9	1.9
Change in costs from previous year ($m)	N/A	0.01	-0.18	-0.14	-0.11	-0.09
Change from previous year (%)	*N/A*	*0.6*	*-7.6*	*-6.5*	*-5.4*	*-4.5*

Where greater reductions in operating costs eventuate than those forecast, a glide path mechanism is proposed for sharing these benefits. This mechanism takes the form of a trigger for a price review in circumstances where revenue is more than 10 per cent above that forecast. How these gains are then shared with users is at the discretion of the regulator.

The access arrangement also provides for the passthrough of changes to existing imposts or the introduction of new imposts.

Envestra

Envestra has proposed progressive reductions in non capital costs for the access arrangement period, reflecting forecast increases in labour productivity and general cost reductions. These costs are shown in Table 18.2 below.

Table 18.2: Percentage change in Envestra operating and maintenance and UAG costs

	00/01	01/02	02/03	03/04	04/05	05/06
Total operating and maintenance costs (including UAG) ($m)	13.6	13.5	13.4	13.3	13.3	13.5
Change in costs from previous year ($m)	N/A	-0.1	-0.1	-0.1	0	0.2
Change from previous year (%)	*N/A*	*-0.7*	*-0.7*	*-0.7*	*0*	*1.5*

Envestra has proposed no adjustments to total revenue or tariffs either within or for any future access arrangement period in the event actual non capital costs differ from forecasts. The access arrangement also provides for the passthrough of changes to existing imposts or the introduction of new imposts.

Other jurisdictions

IPART has adopted CPI-X price cap regulation which sets an average price ($/GJ) for all three gas networks within its jurisdiction (IPART 1999b, 1999f, 2000a). The utilities will keep any additional profits (over the initial access period) resulting from reductions in operating costs and capital efficiency, providing that service standards are maintained. Further, in the event that sales volumes exceed forecasts, this additional revenue will also be retained. The sharing of these benefits will be considered by the regulator at the next review.

In respect of AlintaGas, OffGAR (2000a) has applied a CPI-X price cap mechanism on each individual tariff component for the initial access arrangement period. OffGAR was also of the view that the Code does not permit tax or regulatory change passthrough.

Envestra proposed a number of incentive mechanisms as fixed principles in the access arrangement for the South Australian distribution systems, including a glide path for non capital costs. In considering this approach, SAIPAR (2000a) did not consider an approach which provided for the service provider to be fully rewarded for both controllable and non-controllable gains, with these not passed on to customers until the end of the second access arrangement period, to be appropriate. Instead, it has decided on a partial glide path which allows the service provider to retain controllable gains during the access arrangement, and then pass the gains on to users at the end of the access arrangement period.

Table 18.3 provides a summary of the X-factors determined by the various regulators throughout Australia in respect of gas distribution.

Table 18.3: Gas distribution X-factors

Entity/Author	X-factor
IPART (1999b)	CPI-0.6% (applying each year between 2000-2003)
IPART (1999f)	CPI-2.4% (2000), CPI-2%(2001), CPI-1.7%(2002)
OffGAR (2000a)	CPI-2.55% (applying each year between 2000-2004)
ORG (1998b)	CPI-3% (applying each year between 1998-2002)
SAIPAR (2000)	CPI-4% (2000-02), CPI-7% (2003-04)

The Authority seeks comment on:

- **the most appropriate approach to assessing the efficiency of a network (in particular firm specific approaches versus industry wide approaches);**
- **whether CPI-X is considered the most suitable approach to incentive mechanisms; and**
- **the incentive mechanisms proposed by service providers, including benefit sharing arrangements.**

PART C: OTHER ISSUES

19. GAS DEMAND FORECASTS

To ensure that prices charged by a service provider are consistent with the revenue requirement set by the Authority, it is necessary for the Authority to determine whether estimates of the quantity of gas demanded by customers over the period of the access arrangement are reasonable.

19.1 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.

19.2 Issues in gas demand forecasting

Gas demand forecasts represent an important part of an access arrangement. Forecast demand is used to derive reference tariffs, taking into account the allowed target revenue. Because the costs of providing transportation services are largely fixed, the number of units over which these costs are recovered will affect the price for each service. Higher assumed growth will result in lower prices. Conversely, lower assumed growth will result in higher prices.

During the period of an access arrangement, when the price has been determined based on required revenue and then capped, the service provider bears the volume risk. If growth exceeds the forecast in the access arrangement, revenues will increase. As costs are largely fixed, profits will increase more than proportionately. The converse occurs if growth in demand falls short of forecasts.

Consequently, the service provider has an incentive to:

- propose conservative growth assumptions for the period of the access arrangement; and
- grow the market during the period of the access arrangement.

Arriving at a forecast which provides a reasonable balance of risks and incentives for the service provider requires careful consideration of the history of growth patterns, current demand, and economic conditions.

Summary of access arrangement proposals

Allgas

Allgas distributes approximately 70 per cent of gas delivered by utilities in Queensland. In estimating five year forecasts of gas demand in the Allgas region, Allgas used a number of assumptions about the Queensland economy and developments in the Australian and Queensland gas markets. These key assumptions cover Gross State Product, Australian Gross Domestic Product and Queensland's projected population growth rate. The projections also assumed that the Papua New Guinea Gas Pipeline will be on-stream in 2003-04 bringing lower gas prices with a subsequent increase in fuel switching in major plants and commercial customers to natural gas. This has been estimated to increase gas deliveries to commercial and industrial customers.

Allgas' gas demand forecasts out to 2004-05 are reproduced in Table 19.1.

Table 19.1: Allgas gas demand forecasts

Year Ending 30 June	1999-00 (actual)	2000-01	2001-02	2002-03	2003-04	2004-05
Sales less than 10 TJ*	2,210	2,312	2,398	2,486	2,609	2,701
Change from previous year (%)	*N/A*	*4.6*	*3.7*	*3.7*	*4.9*	*3.5*
Sales greater than 10 TJ#	7,014	7,247	7,411	7,612	7,945	8,193
Change from previous year (%)	*N/A*	*3.3*	*2.3*	*2.7*	*4.4*	*3.1*
Total Sales (TJ)	9,224	9,559	9,809	10,098	10,554	10,895
Change from previous year (%)	*N/A*	*3.6*	*2.6*	*2.9*	*4.5*	*3.2*

* Equivalent to Allgas' Small Customer Class
\# Equivalent to Allgas' Large Customer Class

Envestra

Envestra's demand forecasts have been derived by:

- analysing historical data and trends; and
- examining the key drivers in gas demand, which include:
  - network marketing activity;
  - gas connection penetration and growth;
  - weather effects;
  - population forecasts; and
  - building activity.

Envestra's access arrangement states that, for the domestic section of the gas market, forecasts can be determined reasonably accurately, provided a number of base variables (mainly housing connections, penetration and average consumption per customer) can be established. However, other market segments are impacted significantly by general economic activity and individual consumer demand, which are more difficult to forecast.

In light of the above factors, Envestra has estimated the most likely increase in load growth over the access arrangement period, for each of the demand and volume haulage reference services. The forecasts were arrived at on the assumption that any proposed increase in reference tariffs would not result in significant reductions in throughput. However, Envestra noted that any uncompetitive gas prices would be a major deterrent to market growth.

In forecasting for volume haulage reference services, Envestra has given consideration to economic activity, appliance penetration and fuel substitution factors as well as the outcome of trend analysis.

In respect of the demand delivery sectors (that is, predominantly manufacturing and energy-intensive businesses) most demand comes from a small number of very large customers. The forecasts for these delivery points have relied heavily on available knowledge of current and likely future operation of the associated businesses.

Envestra's gas demand forecasts out to 2005-06 are reproduced in Table 19.2.

Table 19.2: Envestra gas demand forecasts

Year Ending 30 June	**1999-00 (actual)**	**2000-01**	**2001-02**	**2002-03**	**2003-04**	**2004-05**	**2005-06**
Sales less than 10 TJ*	1,712	1,757	1,803	1,854	1,906	1,962	2,019
Change from previous year (%)	*N/A*	*2.1*	*2.6*	*2.8*	*2.8*	*2.9*	*2.9*
Sales greater than 10 TJ#	2,545	2,598	2,654	2,712	2,772	2,834	2,898
Change from previous year (%)	*N/A*	*2.6*	*2.2*	*2.2*	*2.2*	*2.2*	*2.3*
Total Sales (TJ)	4,257	4,355	4,460	4,565	4,680	4,800	4,915
Change from previous year (%)	*N/A*	*2.3*	*2.4*	*2.4*	*2.5*	*2.6*	*2.4*

* Equivalent to Envestra's Volume Haulage Class
\# Equivalent to Envestra's Demand Haulage Class
Note: figures may not add due to rounding.

Other jurisdictions

There are essentially two general approaches to gas demand forecasting relevant to particular circumstances faced by distributors. The first would be a micro-analysis informed by a survey of customers, market analysis (including major changes such as contestability in the retail market) and plans to extend the network. The second method would be a macro-analysis driven by historical trends and relationships between drivers of gas demand, including State Final Demand, population growth, relative energy prices, technology and weather.

Generally service providers have developed gas demand forecasts through the application or combination of both the above mentioned methodologies.

The Authority seeks comment on whether the gas demand projections are fair and reasonable.

20. SERVICE QUALITY STANDARDS

Service standards are generally established to ensure that users receive an appropriate minimum quality of service from service providers throughout a regulatory period. Service standards relate to reliability of the service provided and responsiveness to problems. This differs from gas quality standards, which are a technical matter dealt with by the Queensland Department of Mines and Energy.

20.1 Code requirements

While the Code does not explicitly address service standards, it implicitly assumes that the quality of service provided is reasonable and will be maintained. As part of an access arrangement, a service provider must also include terms and conditions on which services will be supplied. Attachment A to the Code also requires that information be included in access arrangements in relation to key performance indicators for each pricing zone, service or category of asset.

20.2 Issues in service quality standards

A regulated network provider can potentially trade off the quality of service provided against the costs associated with providing that service in order to maximise profits. Prices should therefore reflect not only the cost of providing a service but also the inherent quality of the service.

Users will generally require that some minimum level of service be provided, and that if this level is not maintained, there be some method of recourse. Ideally, users should be able to choose their quality of service by considering a range of alternative price and service quality options.

Customer service standards are likely to be included in revisions to the *Petroleum Act 1923* and the *Gas Act 1965* which are currently being prepared by the Queensland Department of Mines and Energy. It is likely that these will explicitly require gas suppliers to provide a customer service code as well as report on a number of performance indicators.

Summary of access arrangement proposals

Allgas

Allgas has noted in its terms and conditions that the network is to be operated and managed in accordance with the access arrangement and the Code, as well as any relevant legislation or distribution licence requirements.

Envestra

Envestra's access arrangement states that it will provide network services in accordance with certain minimum standards and quality levels as well as subject to the requirements of any distribution licence or applicable law, for example, the Queensland *Gas Act 1965* and associated regulations which govern areas such as metering standards and supply pressure.

Other jurisdictions

Currently the ORG is the only regulator to put in place explicit measures for monitoring the standard of service provided by gas distributors. While certain safety and technical obligations apply to a distributor as part of an access arrangement and as holder of a distribution licence, the ORG, in conjunction with the Office of Gas Safety and distributors, has developed its own series of reliability of supply and service standards, which must be reported on on a quarterly basis.

Regulators in other jurisdictions are not directly involved with standards of service. In Western Australia, South Australia and New South Wales, their respective technical regulators have annual reporting arrangements which to some extent overlap with standards of service. For example, in New South Wales, suppliers must either prepare their own customer service code (for which guidelines are available) or adopt any national service code.

The Authority seeks comment on whether service standards should be developed and monitored as part of the approval of access arrangements.

GLOSSARY

Access Arrangement	an arrangement for access to a Covered Pipeline that has been approved by the Relevant Regulator
Access Arrangement Information	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
Access Arrangement Period	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
Access Dispute	a dispute between a Service Provider and another person that, in accordance with the Code, may be referred to arbitration
Additional Staff	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
Additional Revenue Policy	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)
Anticipated Incremental Revenue	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
Arbitrator	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 – Schedule 1 to the South Australian Act, Part 4, clause 14)
Associate	in relation to a person, has the meaning it would have under Division 2 of Part 1.2 of the Corporations Law if sections 13, 14, 16(2) and 17 of that Law were repealed, except that a person will not be considered to be an Associate of a Service Provider solely because that person proposes to enter, or has entered, into a contract, arrangement or understanding with the Service Provider for the provision of a Service
Associate Contract	a contract, arrangement or understanding between: (a) the Service Provider and an Associate in connection with the provision of a Service; or (b) the Service Provider and any person in connection with the provision of a Service which provides a direct or indirect benefit to an Associate and which is not an arm's length transaction

Backhaul	a Service which notionally transports gas between two points in the opposite direction to actual gas flow
Bare Transfer	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)
Bypass	the construction of a pipeline to avoid the existing Transmission or Distribution system (or part thereof)
Capacity	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
Capacity Management Policy	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)
Capital Base	has the meaning given in section 8.4 of the Code (that is, the value of the capital assets that form the Covered Pipeline)
Capital Contribution	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)
Charge	for a Service, means the amount that is payable by a User to the Service Provider for that Service
City Gate	transition point from high pressure transmission pipelines to distribution network
Code	National Third Party Access Code for Natural Gas Pipeline Systems as changed from time to time in accordance with the Gas Pipelines Access Law
Code Registrar	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 *Gas Pipelines Access (South Australia) Act 1997* of South Australia – Schedule 1 to the South Australian Act, Part 1, clause 2)

Confidential Information	information that is by its nature confidential or is known by the other party to be confidential and includes: (a) any information relating to the financial position of the party and in particular includes information relating to the assets or liabilities of the party and any other matter that affects or may affect the financial position or reputation of the party; (b) information relating to the internal management and structure of the party or the personnel, policies and strategies of the party; (c) information of the party to which the other party has access, other than information referred to in paragraphs (a) and (b), that has any actual or potential commercial value to the first party or to the person or corporation which supplied that information; and (d) any information in the party's possession relating to the other party's clients or suppliers and like information
Contracted Capacity	that part of the Capacity which has been reserved by a User or Users pursuant to a contract entered into with the Service Provider
Contract Carriage	is a system of managing third party access whereby: (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; (b) Users normally are required to enter into a contract that specifies a quantity of Service; (c) charges for use of a Service normally are based at least in part upon the quantity of Service specified in a contract; and (d) a User normally has the right to trade its right to obtain a Service to another User
Core Provisions	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
Coverage/Covered	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
Covered Pipeline	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
Delivery Point	the point or points within the Covered Pipeline at which the custody of Natural Gas is transferred from a Service Provider to a User
Depreciated Actual Cost	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

Depreciated Optimised Replacement Cost (DORC)	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
Depreciation	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
Depreciation Schedule	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)
Developable Capacity	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
Distribution	the transportation of gas over a combination of high pressure and low pressure pipelines from a City Gate to various customers' usage points
End User	means a person who: (a) acquires or proposes to acquire Natural Gas from a User; or (b) proposes to acquire Natural Gas from a Prospective User
End User Information	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
Equivalent Tariff	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
Exclusivity Right	a contractual right that by its terms either: (a) expressly prevents a Service Provider supplying Services to persons who are not parties to the contract; or (b) expressly places a limitation on the Service Provider's ability to supply Services to persons who are not parties to the contract, but does not include a User's contractual right to obtain a certain volume of Services
Extensions/ Expansions Policy	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

Final Approval Request	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)
Fixed Period	has the meaning given in section 8.47 of the Code (that is, the period during which a Fixed Principle may not be changed)
Fixed Principle	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)
Gas Pipelines Access Law	in relation to Queensland, means: (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 (b) Regulations in force under Part 3 of the South Australian Act, as applying as a law of that Scheme Participant
Incentive Mechanism	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 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)
Incremental Capacity	the increase in Capacity attributable to a New Facility
Incremental Revenue	revenue generated by sales of Incremental Capacity
Incremental User	a User that could not have been serviced without the addition of the Incremental Capacity
Information Package	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)
Interruptible Supply	a Service which does not guarantee to supply gas at requested levels
Jurisdictional Area	has the meaning given in the Gas Pipelines Access Law (that is, the area within the limits of a state or territory including all waters in the area – Schedule 1 to the South Australian Act, Part 1, clause 2)
Load Factor	the ratio between average yearly load and peak daily load
Local Appeals Body	in the case of Queensland, the Queensland Gas Appeals Tribunal

Local Minister	the local Minister within the legislation for that scheme participant (in the case of Queensland, the Minister for Mines and Energy)
Local Regulator	in the case of Queensland, the Queensland Competition Authority
Market Carriage	a system of managing third party access whereby: (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; (b) Users are normally not required to enter a contract that specifies a quantity of Service; (c) charges for use of Services are normally based on actual usage of Services; and (d) a User normally does not have a right to trade its right to obtain a Service to another User
Market Variable Element	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
Marketable Parcel	all or part of a User's Contracted Capacity which the User reasonably expects: (a) that the User will not utilise and does not require for technical or safety reasons; (b) to be of a size and type capable of being sold to another User or to a Prospective User; and (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
Marketing Staff	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: (a) strategic decision making, including the executive officer or officers to whom Marketing Staff report either directly or indirectly; (b) technical, administrative, accounting or service functions
National Gas Pipelines Access Agreement	a national agreement endorsed by the Council of Australian Governments and signed by all Australian Heads of Government on 7 November 1997 to introduce a national gas pipelines access regime

Natural Gas	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 – Schedule 1 to the South Australian Act, Part 1, clause 2)
New Facilities Investment	has the meaning given in section 8.16 of the Code (that is, the amount by which the Capital Base may be increased is the amount of the actual capital cost incurred (New Facilities Investment), provided that this does not exceed the amount that would be invested by a prudent Service Provider acting efficiently)
New Facility	means: (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; and (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)
Non Capital Costs	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)
Non Reference Service	a service other than a Reference Service
Optimised Deprival Value	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
Pipeline	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 – Schedule 1 of the South Australian Act, Part 1, clause 2)
Prevailing Tariff	for a Reference Service means the applicable Reference Tariff, and for any other Service, means the Equivalent Tariff
Prospective Incremental User	a person who may become an Incremental User
Prospective Service Provider	a person who seeks or may seek to become a Service Provider
Prospective User	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

Public Register	the public register to be kept by the Code Registrar pursuant to section 7.10 of the Code
Queensland Gas Appeals Tribunal	the relevant local appeals body in Queensland
Queuing Policy	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)
Rate of Return	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)
Rebatable Service	is a Service where: (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 (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
Receipt Point	the point or points within the Covered Pipeline at which the custody of Natural Gas is transferred from a User to a Service Provider
Recoverable Portion	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)
Redundant Capital	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)
Reference Service	a Service which is specified in an Access Arrangement and in respect of which a Reference Tariff has been specified in that Access Arrangement
Reference Tariff	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
Reference Tariff Policy	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)
Related Business	the business of producing, purchasing or selling Natural Gas, but does not include purchasing or selling of Natural Gas to the extent necessary: (a) for the safe and reliable operation of a Covered Pipeline; or (b) to enable a Service Provider to provide balancing services in connection with a Covered Pipeline

Relevant Appeals Body	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 – Schedule 1 of the South Australian Act, Part 1, clause 2. In the case of Queensland, the Queensland Gas Appeals Tribunal)
Relevant Minister	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 – Schedule 1 of the South Australian Act, Part 1, clause 2)
Relevant Regulator	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 – Schedule 1 of the South Australian Act, Part 1, clause 2. In the case of Queensland, the QCA is the Relevant Regulator)
Residual Value	has the meaning given in section 8.4 of the Code (that is, the assumed residual value of the Covered Pipeline at the end of the Access Arrangement Period)
Revisions Commencement Date	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)
Revisions Submission Date	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)
Ring-fencing	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
Scheme Participant	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 – Schedule 1 of the South Australian Act, Part 1, clause 2)
Service	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): (a) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul); (b) the right to interconnect with the Covered Pipeline; and (c) services ancillary to the provisions of such services, but does not include the production, sale or purchasing of Natural Gas
Services Policy	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)

Service Provider	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– Schedule 1 of the South Australian Act, Part 1, clause 2)
Spare Capacity	means: (a) in relation to a Covered Pipeline described in the Access Arrangement as a Contract Carriage Pipeline: (i) the difference between the Capacity and the Contracted Capacity; plus (ii) the difference between the Contracted Capacity and the Contracted Capacity which is being used; and (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
Speculative Investment	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)
Speculative Investment Fund	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)
Structural Element	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
Surcharge	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)
Take or Pay	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

Tariff	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)
Tender Approval Request	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)
Total Revenue	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)
Trading Policy	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)
User	a person who has a current contract for a Service, or an entitlement to a Service as a result of an arbitration

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APPENDIX A

ALTERNATIVE MEASURES OF WACC

Classical tax system

As noted by Officer (1994), under a classical tax system, the appropriate definition of a company's pre tax weighted average cost of capital can be expressed as follows:

Cash Flow	WACC
X_0	$r_o = \frac{r_e}{(1-T)}\frac{E}{(E+D)} + r_d\frac{D}{(E+D)}$ where r_e is the return on equity r_d is the return on debt (the cost of debt) E is the market value of equity D is the market value of debt

The amount of tax collected from the company under a classical tax system by the government can be found as $X_g = T(X_0 - X_d)$. Hence,

$$X_0 = T(X_0 - X_d) + X_e + X_d$$

which converts to:

$$X_0(1-T) = X_e + X_d(1-T)$$

The after tax weighted average cost of capital under a classical tax system can be expressed as either:

Cash Flow	WACC
$X_0(1\text{-}T)$	$r_1^c = r_e\frac{E}{(E+D)} + r_d(1-T)\frac{D}{(E+D)}$
$X_0 - (X_0 - X_d)T_c$	$r_2^c = r_e\frac{E}{(E+D)} + r_d\frac{D}{(E+D)}$

Dividend imputation system

Under the dividend imputation tax system shareholders recover, via imputation tax credits, some proportion of the corporate taxes that have already been paid. This has two effects relevant to the calculation of WACC. First, it decreases the effective corporate tax rate and thereby increases the cash flows to shareholders. Second, the decrease in the effective tax rate will reduce the effective tax shield provided by debt relative to equity. Therefore, under dividend imputation, it is necessary to allow for increased cash flow to shareholders and the increased after tax cost of debt.

In the presence of dividend imputation, the effective tax rate changes from Tc to Tic = Tc(1-γ) where

- Tc is the statutory tax rate (equivalent to the classical tax rate); and
- γ is the value of imputation credits and represents the proportion of tax collected from the company which gives rise to the tax credit associated with a franked dividend.

In the presence of dividend imputation, the appropriate definition of a company's pre tax weighted average cost of capital can be expressed as:

Cash Flow	WACC
X_0	$r_o = \frac{r_e}{\left(1-T_c\left(1-g\right)\right)}\frac{E}{\left(E+D\right)} + r_d\frac{D}{\left(E+D\right)}$

Under dividend imputation, the effective level of company tax is defined as:

$$X_g = T\left(X_0 - X_d\right) - gT\left(X_0 - X_d\right)$$
$$= T\left(X_0 - X_d\right)\left(1-g\right)$$

Hence:

$$X_0 = \left(X_0 - X_d\right)T_c\left(1-g\right) + X_e + X_d$$

which converts to:

$$X_0\left(1-T_c\left(1-g\right)\right) = X_e + X_d\left(1-T_c\left(1-g\right)\right)$$

In the presence of dividend imputation, the appropriate definition of a company's post tax weighted average cost of capital can be expressed as:

Cash Flow	WACC
$X_0(1-T_c)$	$WACC\ 1 = r_e \frac{(1-T_c)}{(1-T_c(1-g))}\frac{E}{(E+D)} + r_d(1-T_c)\frac{D}{(E+D)}$
$X_o(1-T_c(1-g))$	$WACC\ 2 = r_e \frac{E}{(E+D)} + r_d(1-T_c(1-g))\frac{D}{(E+D)}$
$X_0 - (X_0 - X_d)T_c(1-g)$	$WACC\ 3 = r_e \frac{E}{(E+D)} + r_d \frac{D}{(E+D)}$
$X_0(1-T_c) + gT_c(X_0 - X_d)$	$WACC\ 4 = r_e \frac{E}{(E+D)} + r_d(1-T_c)\frac{D}{(E+D)}$

When expressing WACC in post tax nominal terms in the presence of dividend imputation, there are several alternative specifications available which the Authority will refer to as WACC 1 to WACC 4.

Under WACC 1, cash flows are presented as the standard after tax definition of cash flows under a classical system. This results in an over statement of tax and imputation in relation to equity, and the tax shield for debt is ignored. The WACC must fully account for the imputation effects.

Under WACC 2, all operating income is taxed at the company tax rate adjusted for imputation. However, tax is still overstated in the cash flows as the tax shield for debt is ignored. The WACC must correct for the overstated tax shield.

Under WACC 3, the effective after corporate tax income attributable to equity and debt holders is fully and correctly recognised in the cash flows. The net impact of this approach is that it keeps all tax adjustments out of the WACC and recognises them directly in the cash flows.

Under WACC 4, imputation is fully and correctly recognised as a modified cash flow but tax is overstated as the debt shield is ignored. The WACC must correct for the overstated tax effect.

Each of the measures involves different specifications of WACC and an accompanying adjustment to the cash flows being analysed. These methods are discussed in detail by Officer (1994) who demonstrates that when they are applied correctly they all result in the same value for the entity.

APPENDIX B

THE RELATIONSHIP BETWEEN EQUITY, DEBT AND ASSET BETAS

The WACC relationship expresses the entity's cost of capital as the weighted average of the required return on its equity and debt. Because of the equivalence between the assets of the entity to a portfolio of the entity's equity and debt with respective weights of $\frac{E}{E+D}$ for equity and $\frac{D}{E+D}$ for debt, the return on assets can be expressed as follows:

$$R_a = R_e\left(\frac{E}{E+D}\right) + R_d\left(\frac{D}{E+D}\right)$$

Substituting CAPM for each of the returns (R_a, R_e and R_d) gives:

$$R_f + b_a\left(R_m - R_f\right) = \left(R_f + b_e\left(R_m - R_f\right)\right)\left(\frac{E}{D+E}\right) + \left(R_f + b_d\left(R_m - R_f\right)\right)\left(\frac{D}{D+E}\right)$$

which is equivalent to:

$$b_a = b_e\left(\frac{E}{D+E}\right) + b_d\left(\frac{D}{D+E}\right)$$

An asset beta represents the risk arising from the sensitivity, or covariance, of the operating cash flows generated by the assets of an entity compared with the market in general. Asset betas are not directly observable and therefore must be derived directly from equity betas. The difference between an asset beta and an equity beta reflects the extent to which debt is used to finance the entity's assets.

It is obvious from above that the beta of an entity's assets is equal to the betas of the entity's equity and debt weighted by the respective weights for equity and debt. Whilst equity and debt betas can be calculated via CAPM based methods, the asset beta can only be inferred via the above relationship.

Issues in the estimation of the equity beta

An entity's equity beta (β_e) reflects both the market risk associated with its assets and the financial risk born by shareholders due to the entity's use of debt financing. CAPM assumes that a linear relationship exists between an entity's gearing and the premium associated with that gearing. Two factors have been identified as key determinants of an entity's equity beta:

- financial leverage – the ratio of debt to equity, where a higher level of debt implies a higher beta; and
- sensitivity to cash flows – relative to overall economic activity, where more cyclical cash flows are associated with higher betas.

Typically, equity betas are estimated using historical data through the application of the market model which is derived from CAPM (expanded as follows):

$$R_i = R_f + b_i R_m + b_i R_f$$

$$R_i = R_f (1 - b_i) + b_i R_m$$

$$R_i = a_i + b_i R_m$$

where

a_i is equal to $R_f (1 - b_i)$

b_i is the equity beta

The estimation of equity betas is not without controversy. There are numerous issues relevant to its estimation that the Authority will be required to consider, including the following:

- the choice of return measure – for example whether returns should be discrete or continuously compounded, whether raw or excess returns should be used and whether nominal or real returns should be used. Typically the risk free rate and market risk premium are both expressed as discretely compounded returns;

- the choice of proxy for the market portfolio. By definition, the measurement of a beta is relative to a market risk premium, which in turn relates to a single specific market. Accordingly, beta estimates for a company differ depending on which stock market index is used – systematic risk is largely country specific and meaningful beta estimate can only be derived using a national index from a company's own country of operation. Therefore caution is required in comparing betas of companies operating in similar industries but in different countries as betas reflect the risk of a company relative to the market in which it operates. Differences in market composition of national share markets do not facilitate direct comparison of betas. As outlined in Table B1, the Australian stock market has a greater component of resource stocks, which account for 16.5 per cent of total Australian market capitalisation. This suggests that the ASX may have a different risk profile compared with the US stock market (where resources stock account for 6.9 per cent of total US stock market capitalisation, and 7.4 per cent of total UK stock market capitalisation). The increased diversification of the Australian market relative to the US and UK markets would suggest that betas for comparable companies in the US and UK will be higher than in Australia;

Table B1: Composition of market indices

Index (as at 30 Nov 1998)	Resource Sector	Industrial Sector	Market Capitalisation
Australian All Ordinaries Accumulation Index	16.5%	83.5%	A$417.0 billion
US Standard & Poors 500	6.9%	93.1%	US$10.6 trillion
UK FTSE 100	7.4%	92.6%	£1.04 trillion

- the sampling interval for the data and the length of the estimation period. Estimates using short interval data (measured at daily or weekly intervals) are systematically biased, such that highly traded securities are over stated whilst those of infrequently traded securities

are understated. Alternatively, use of long intervals (measured quarterly or annually), lowers the number of data points used in the estimation process and diminishes the accuracy of beta measures. Empirical evidence discussed in Brailsford, Faff and Oliver (1997) shows that beta estimates using monthly data estimated over 4 to 5 year intervals provide the most reasonable trade off between the number of observations and the stability of beta estimates;

- the selection of an appropriate method to estimate beta so as not to violate distributional assumptions and to decide how outliers will be considered. Beta is typically estimated using the market model, using an ordinary least squares approach which has the following limiting assumptions:
  - the errors from the regression have a mean of zero;
  - the errors have a common constant and finite variance (homoscedasticity);
- the errors are not correlated with each other over time or with the market risk premium;
- the dependant and explanatory variables are measured without error. Violation of this assumption results in an errors in variables problem. However, the only effect of the presence of measurement error in the dependent variable will be to increase the error variance. The slope parameter will be unbiased and consistent. If the explanatory variable is measured with error this will result in an errors in variables problem biasing the beta coefficient and making it inconsistent. The degree of bias and inconsistency are related to the variance of the measurement error and will result in an underestimation of the true regression parameter or beta coefficient if ordinary least squares techniques are applied;
- the error term is uncorrelated with that from another regression;
- Using these assumptions the estimated coefficients of $\hat{a}_i$ and $\hat{b}_i$ are the best linear unbiased estimates (BLUE) of the parameters a_i and b_i. The presence of a BLUE estimator suggests that the relationship is linear and that the estimated coefficients are efficient and unbiased estimates of the 'true' coefficients. If the assumptions are violated two results can occur:
  - biased sample estimates of the coefficients; and
  - standard formulas and tests for statistical significance are invalid.

  The estimation of the coefficients using OLS techniques have typically produced unstable estimates of beta due to findings of heteroscedasticity (non-constant or time varying volatility of the regression errors) and autocorrelation in the residuals. Other findings suggest the presence of non-normality in the residuals, outliers, non-linearity in the relationship between the return on the asset and the market return, non-stationarity in beta estimates, or the possibility of omitted variables such as firm size or seasonalities;
- measurement errors in the data and the choice of a variety of methods to avoid thin trading biases. Thin trading bias arises when shares go through extended periods of non-trading despite movements in the market index during the same period. Hence, non-trading will cause a reduction in the correlation and covariance between the share return and the market return. Several methods are available for adjust beta for thin trading bias such as the methods suggested by Scholes & Williams (1977) and Dimson (1979);

- issues of beta stability including whether beta mean reverts, how beta behaves in the presence of structural breaks and the time variation of beta. Brailsford, Faff and Oliver (1997) identified two related notions of beta instability – 'inter period' instability and 'intra period' instability. The former arises due to instability of beta between the estimation period and the 'application' period. The other arises due to instability of beta during the estimation period. The primary reasons for inter period instability are due to:

  – mean reversion in the beta where beta has been found to have a regression tendency over time towards the Grand Mean of 1. Over time, high betas tend to move down and low betas tend to move up. The Australian study by Castagna and Matolcsy (1978) found that it was possible to adjust the estimated OLS beta as follows:

  $$b_i^{CM} = 0.541 + 0.464\hat{b}_i$$

  A study by Brooks and Faff (1997) compared a series of adjustments to betas estimated from a market model during Australian data during the period 1983-1987 and also found that the adjustment based on the following provided a very useful adjustment:

  $$b_i^{BF} = 0.50 + 0.50\hat{b}_i$$

  – structural breaks in the underlying economy involving clear deliniation in the underlying market that affect all participants – examples include the shift from a classical to the imputation taxation system in 1987 and the floating of the Australian dollar in December 1983. Care must be taken in the identification of break points as there may be prior learning about the break event, leaning of the consequences of the event or the break may involve a structural change over several months or years;

- the primary reasons for intra period instability are due to:

  – changes in firm specific factors during the estimation period such as a change in core business or business divestment;

  – changes in market factors such as the level of financial leverage or shifts in the business cycle;

- the Authority regards the stability of beta as an important issue in identifying the appropriate equity beta for gas distribution businesses. Empirical evidence from Australian markets strongly supports the mean reversion of beta. Raw beta values, derived from historical data, can be adjusted based on the assumption that beta factors change over time especially in industries where there is considerable structural reform underway. International studies supporting the use of adjusted betas include Blume (1971, 1975) and Sharpe, Alexander and Bailey (1995). The true beta has a tendency over time to move toward the market average of one and this adjustment may be represented as: Adjusted (future) beta = Raw Beta * (0.67) + 0.33. This is the approach adopted by Bloomberg, which appears to be more generally accepted by practitioners.

  The Authority is conscious that it may be appropriate to use the Bloomberg adjustment factor as follows when estimating betas:

  *Adjusted beta = 0.33 + 0.67*b_i

- the possibility of omitted variables in the estimation of beta due to entity size characteristics, seasonalities, changes in industry structure or the regulatory framework. For example, empirical evidence suggests that there is an inverse correlation between market capitalisation and systematic risk (beta). As noted by Berk (1995) smaller entities tend to have higher betas than larger entities.

Issues in the estimation of debt betas

The debt beta (β_d) reflects the financial risk born by shareholders due to the entity's use of debt financing. The CAPM can be used to identify the debt beta.

$$R_d = R_f + b_d \left[R_m - R_f \right]$$

Transformed

$$b_d = \frac{\left(R_d - R_f \right)}{\left[R_m - R_f \right]}$$

where

R_f = the risk free rate

R_m = the expected return on the market portfolio of risky assets

R_d = the expected return on debt

$b_d = \frac{Cov\left(R_d, R_m \right)}{Var\left(R_m \right)}$ = the debt beta

$\left[R_m - R_f \right]$ = the equity risk premium

The debt beta calculation is very sensitive to the size of the market risk premium. If the market risk premium increases this will have the impact of reducing the size of the debt beta. The ACCC (2000a) and ORG (2000) have used the above CAPM based approach to calculate the debt beta.

It is acknowledged that the cost of debt funding can distort the level of the return to debt holders. However, equity capital also involves administrative and underwriting costs which would distort the return to equity holders by effecting the initial issuance price of the equity. Trading of equity market also involves brokerage fees.

Issues in the estimation of asset betas

The CAPM assumes a linear relationship between the equity beta and the gearing of an entity. Hence, it is possible to calculate asset betas from equity betas. The asset beta refers to the beta applicable to the assets of an entity that has no debt. The gearing of the entity needs to be taken into account in estimating asset betas because default risk is incorporated in equity values and this needs to be removed to arrive at the entity's risk profile independent of its financial structure. The adjustment of estimated equity betas to remove the financial risk associated with a security, leaving the risk of the asset encapsulated in the asset beta (β_a) is known as delevering of the equity beta.

The textbook approach to the process of delevering and relevering generally involves the following procedural steps:

- estimate the equity beta of a comparable company or group of companies;

- convert the comparator's estimated equity beta to its asset (or delevered) beta using a delevering formula and the comparator's current leverage ratio. The purpose of this adjustment is to purge the effects of financial (or leverage) risk and leave the risk that reflects the underlying business risk only; and

- relever the asset beta obtained in the previous step using the entity of concern's current leverage in conjunction with a relevering formula.

The resultant figure should then be an estimate of the equity beta for the entity of concern.

It is worth noting that while it is possible to delever beta factors of particular companies to derive asset betas, and to then relever betas to reflect a more appropriate or comparable financial structure, this technique is subject to considerable estimation error and gives a misleading impression as to the precision of the entire methodology. Caution must be used in the use of relevered betas as the relationship between gearing and the returns typically expected by shareholders is non-linear.

There are several approaches to delevering and relevering betas and there is no consensus about which is the most appropriate method. The QCA identified the following methods extensively used by academics and regulators to delever and relever equity betas. They have been broadly categorised by the QCA as:

- the standard or textbook approaches including both the Brealey Myers and Conine approaches;

- the Davis approach; and

- the Appleyard & Strong / Monkhouse approach.

Each of these approaches is discussed below. As noted by the ORG (2000):

> "The impact on the estimated after-tax WACC of using a different debt beta and levering approaches [is] not significant, however, *provided* that the same approach is used when deriving a proxy asset beta from the comparable entities, as is used when deriving a proxy asset beta back into an equity beta."

The main reason for differing approaches may be attributed to the fact that often the issue of cost of capital is divorced from the underlying cash flow of the regulated business. There are a myriad number of ways to estimating cash flows and each variation has implications for the determination of cost of capital. For example, the basic difference between the Officer approach (and CS First Boston) and the Monkhouse approach (recommended by Professor Davis and adopted by ACCC, ORG and IPART) is that with the Monkhouse approach, the value of the imputation tax credit is taken into account in the CAPM. However, with the Officer approach the value of imputation credits is taken into account in the cash flows or directly in the WACC formula. Correctly applied, both approaches are consistent. Therefore, from a theoretical perspective, either approach is sound and the only issue comes down to which is more empirically valid or practically easier to apply because they require different approaches to estimation.

Standard or textbook approaches

There are the following variations of delevering formulae, which appear in textbooks such as Brealey and Myers (2000) that are regarded as standard. The first two formulae outlined below are the most common but rely on an assumption of active debt management while the other two are often provided by textbooks as alternatives but rely on an assumption of passive debt management.

The debt management practices of the entity have direct implications for the choice of delevering formula. The academic literature identifies two approaches:

- active debt management, where the entity is assumed to maintain a predetermined gearing ratio. Here the level of debt in each period is contingent on the calculated value of the entity at the beginning of the period; and

- passive debt management, where the entity is assumed to maintain a pre-specified debt schedule, specified in advance, regardless of the outcome of future cash flows.

Brealey Myers (2000) approach – active debt management, non-zero debt beta

A common textbook approach (advocated by Officer (1998)) assumes an adjustment of debt in each period to keep it a constant proportion of the market value of the enterprise. This approach is widely used and has been adopted by CS First Boston.(1997). The approach is a direct derivation from the asset beta formula. It is represented by the following equation:

$$b_e = b_a + (b_a - b_d) \times \frac{D}{E} \qquad \text{and} \qquad b_a = \frac{b_e + b_d \times \frac{D}{E}}{1 + \frac{D}{E}}$$

where:

β_e = equity beta

β_a = asset beta

β_d = debt beta

D = value of debt

E = value of equity

This approach can be expressed for zero debt beta which assumes that the only impact which debt has on the value of the firm arises out of the tax deductibility of debt interest expense (hence the debt beta is set to zero). This approach is a common simplification of the above approach and is expressed as follows:

$$b_e = b_a \times \left(1 + \frac{D}{E}\right) \qquad \text{and} \qquad b_a = \frac{b_e}{\left(1 + \frac{D}{E}\right)}$$

Conine (1980) approach – passive debt management, non-zero debt beta

A less common approach assumes that an initial proportion of the overall enterprise value is borrowed and held with predetermined debt and interest payments (which may be referred to as a passive debt management policy).

$$b_e = b_a + (b_a - b_d) \times (1 - T) \times \frac{D}{E} \qquad \text{and} \qquad b_a = \frac{b_e + b_d \times (1 - T)\frac{D}{E}}{1 + (1 - T)\frac{D}{E}}$$

where:

T = corporate tax rate

A simplification of the above approach is to implicitly assume a zero debt beta and hence a cost of borrowing equal to the risk free rate. The resulting delevering formula can be expressed as follows:

$$b_e = b_a \times \left[1 + (1 - T) \times \frac{D}{E}\right] \quad \text{and} \quad b_a = \frac{b_e}{1 + (1 - T)\frac{D}{E}}$$

Davis approach – passive debt management, zero debt beta

After critiquing the standard textbook approach, Davis (1998) advocates an approach, which incorporates an imputation adjustment on the passive debt management approach and results in the following formula:

$$b_e = b_a \times \left\{1 + \left[1 - (1 - g) \times T\right] \times \frac{D}{E}\right\} \quad \text{and} \quad b_a = \frac{b_e}{1 + \left[1 - (1 - g) \times T\right] \times \frac{D}{E}}$$

where:

γ = gamma

The above approach may be expanded to accommodate a non-zero debt beta as outlined in the formula below:

$$b_e = b_a + (b_a - b_d) \times \left[1 - (1 - g) \times T\right] \times \frac{D}{E} \quad \text{and} \quad b_a = \frac{b_e + b_d \times \left[1 - (1 - g) \times T\right] \times \frac{D}{E}}{1 + \left[1 - (1 - g) \times T\right] \times \frac{D}{E}}$$

Davis (1998) argues that the use of the standard textbook approach such as Brealey Myers, ignores the impact of corporate tax on the leverage factor and is correct only in two circumstances:

- if there is no income tax; or
- if the imputation system operates perfectly (with gamma = 1) in the sense that all corporate tax payments are washed out by offsetting reductions in shareholder tax payments.

Appleyard and Strong (1989) – non zero debt beta

Appleyard and Strong propose an alternative relationship between levered and unlevered asset betas as a result of adopting an active debt management policy. The formula is outlined as follows:

$$b_e = b_a + (b_a - b_d) \times \left(1 - \frac{r_d}{1 + r_d} \times T\right) \times \frac{D}{E}$$

$$b_a = \frac{b_e + b_d \times \left(1 - \frac{r_d}{1 + r_d} \times T\right) \times \frac{D}{E}}{1 + \left(1 - \frac{r_d}{1 + r_d} \times T\right) \times \frac{D}{E}}$$

where:

r_d = nominal pre-tax cost of debt

Monkhouse – non zero debt beta

Monkhouse modifies the Appleyard and Strong approach by replacing the corporate tax rate (T) with the effective tax rate (T_e) and recognising imputation tax credits.

$$b_e = b_a + (b_a - b_d) \times \left(1 - \frac{r_d}{1+r_d} \times T_e\right) \times \frac{D}{E}$$

$$b_a = \frac{b_e + b_d \times \left(1 - \frac{r_d}{1+r_d} \times T_e\right) \times \frac{D}{E}}{1 + \left(1 - \frac{r_d}{1+r_d} \times T_e\right) \times \frac{D}{E}}$$

where T_e is the effective tax rate equivalent to $T_c(1-\gamma)$.

The approach to delevering and relevering betas should not only recognise the uncertainty regarding the method to apply but should also consider the uncertainty in estimating the relative gearing ratio in the first instance. This is because there is the issue of whether the beta measured over an observed period reflects the historical gearing level reported in the balance sheet or return the market expectation as to future gearing levels. Also, as noted by Macquarie Risk Advisory Services Ltd (1998) with the widespread use of hedging instruments, there are often practical difficulties in estimating an enterprise's debt costs relative to the risk free rate from publicly available information. Any estimate of debt beta may therefore be compromised.

The ACCC recognised that there are a number of formulae used to convert an asset beta to an equity beta. The ACCC considers the Monkhouse approach to be the most appropriate. During 1999 whilst considering gas access arrangements, IPART switched from the extended non zero debt beta Davis formula to the Monkhouse formula. In the draft decision for the access arrangement for AGL Gas Network Limited, IPART (1999d) used the Monkhouse formula. ORG originally adopted the zero debt beta Davis approach in May 1998 but also applied the Monkhouse formula in the final decision in October 1998. Macquarie Risk Advisory Services Limited found that the Monkhouse approach produced a very similar result to the widely used standard textbook approach and advocated by both Officer and CS First Boston.(1998). As noted by the ORG:

> "The consensus of experts appears to be that CSFB's approach estimates the upper limit of the debt beta (that is, it assumes that all of the default risk is systematic) and Davis' approach provides the lower limit (that is, it assumes that none of the default risk is systematic), and that the real number must be somewhere between."

As discussed above, there is a range of alternative options available for the estimation of beta, along with the other assumptions required for the determination of a return on equity under CAPM.