Allgas Energy Limited

ABN 009 656 446

Access Arrangement Information for the Queensland Network

12 November 2001

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1 INTRODUCTION

1.1 Purpose of this document

The following Sections in the National Third Party Access Code for Natural Gas Pipeline Systems set out the requirements for this Access Arrangement Information.

1.2 Code Requirements

2.6 Access Arrangement Information must contain such information as in the opinion of the Relevant Regulator would enable Users and Prospective Users to:

(a) understand the derivation of the elements in the proposed Access Arrangement; and

(b) form an opinion as to the compliance of the Access Arrangement with the provisions of the Code.

2.7 The Access Arrangement Information may include any relevant information but must include at least the categories of information described in Attachment A.

2.8 Information included in Access Arrangement Information, including information of a type described in Attachment A, may be categorised or aggregated to the extent necessary to ensure the disclosure of the information is, in the opinion of the Relevant Regulator, not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User. However, nothing in this Section 2.8 limits the Relevant Regulator's power under the Gas Pipelines Access Law to obtain information, including information in an uncategorised or unaggregated form.

1.3 Contact details

The contact for further details on this Access Arrangement Information is:

Chief Executive Officer
Allgas Energy Ltd
150 Charlotte Street
Brisbane Qld 4000
GPO Box 1461
Brisbane 4001 Australia
Tel: (07) 3404 1822
Fax : (07) 3404 1821

1.4 Information Requirements

The following information is required under the Code.

Attachment A: Information Disclosure By A Service Provider To Interested Parties

Pursuant to Section 2.7, the following categories of information must be included in the Access Arrangement Information.

The specific items of information listed under each category are examples of the minimum disclosure requirements applicable to that category but, pursuant to Sections 2.8 and 2.9, the Relevant Regulator may:

- *allow some of the information disclosed to be categorised or aggregated; and*
- *not require some of the specific items of information to be disclosed,*

if in the Relevant Regulator's opinion it is necessary in order to ensure the disclosure of the information is not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User.

Category 1 Information Regarding Access & Pricing Principles

Tariff determination methodology

Cost allocation approach

Incentive structures

Category 2: Information Regarding Capital Costs

Asset values for each pricing zone, service or category of asset

Information as to asset valuation methodologies - historical cost or asset valuation

Assumptions on economic life of asset for depreciation

Depreciation

Accumulated depreciation

Committed capital works and capital investment

Description of nature and justification for planned capital investment

Rates of return - on equity and on debt

Capital structure - debt/equity split assumed

Equity returns assumed - variables used in derivation

Debt costs assumed - variables used in derivation

Category 3: Information Regarding Operations & Maintenance

	Fixed versus variable costs
	Cost allocation between zones, services or categories of asset & between regulated/unregulated
	Wages & Salaries - by pricing zone, service or category of asset
	Cost of services by others including rental equipment
	Gas used in operations - unaccounted for gas to be separated from compressor fuel
	Materials & supply
	Property taxes
Category 4:	*Information Regarding Overheads & Marketing Costs*
	Total service provider costs at corporate level
	Allocation of costs between regulated/unregulated segments
	Allocation of costs between particular zones, services or categories of asset
Category 5:	*Information Regarding System Capacity & Volume Assumptions*
	Description of system capabilities
	Map of piping system - pipe sizes, distances and maximum delivery capability
	Average daily and peak demand at "city gates" defined by volume and pressure
	Total annual volume delivered - existing term and expected future volumes
	Annual volume across each pricing zone, service or category of asset
	System load profile by month in each pricing zone, service or category of asset
	Total number of customers in each pricing zone, service or category of asset
Category 6:	*Information Regarding Key Performance Indicators*
	Industry KPIs used by the Service Provider to justify "reasonably incurred" costs
	Service provider's KPIs for each pricing zone, service or category of asset

2 REVENUE DETERMINATION

2.1 Code Requirements

8.4	*Total revenue should be calculated according to one of the following methodologies.* *A Cost of Service approach – calculated on the basis of a rate of return on the capital base, plus depreciation of the capital base plus the operating, maintenance and other non-capital costs of the network.* *An Internal Rate of Return (IRR) approach – total revenue will provide a forecast IRR consistent with the Code's principles regarding the weighted average cost of capital and considering all of the costs, including capital costs..* *A Net Present Value (NPV) approach – total revenue will provide a forecast NPV of zero considering all of the costs, including capital costs. The discount rate used in the NPV approach should be consistent with the weighted average cost of capital.*

2.2 Overview of the Allgas Approach

The Allgas Energy Ltd (Allgas) revenue determination is essentially a cost of service approach and accords with the above Code requirements. The annual revenue targets have been determined as shown in the following steps. Details of each step are shown in subsequent Sections.

Step 1 : Establish the base year costs and starting capital base.

Allgas has taken 1999/00 as its base year. This provides for maximum integrity of data, given that actual results are known. The base year parameters include:

- Operating, Maintenance and other non-capital costs (O&M);
- Costs of Unaccounted for Gas (UAG);
- Capital Base – based on DORC;
- Depreciation;
- WACC (post-tax nominal).

The capital base for the base year has been established by adding half the amount of depreciation and capital expenditure for the year to the opening asset base. The closing balance for the base year (also the opening balance for the following year) has been determined by rolling forward the starting balance to account for full capital expenditure, depreciation and asset indexation.

Step 2: Establish the base year revenue

The base year revenue is determined according to the following formula:

Base Revenue = WACC * Capital base – CPI change in asset base + Depreciation + O&M + UAG + Tax payable – Franking credits

where: capital base = DORC – 0.5 * Depreciation + 0.5 * Capital expenditure; and

CPI change in asset base = CPI *capital base.

Step 3: Establish future costs

Forecast costs have been established for:

- O&M
- UAG
- Depreciation
- Capital expenditure

Step 4: Establish future year raw revenues

Each future year's revenue is determined according to the following formula noted above.

Step 5: Apply price smoothing

The prices ($/GJ) are smoothed to provide a consistent transition over the access arrangement period.

The following Sections provide further details of the various components of revenue.

3 OPERATIONS & MAINTENANCE

3.1 Approach

Forecasts of operational (ie non-capital) costs have been developed by Allgas for the five years to 2005/06 of the access arrangement. Allgas has included significant operating efficiency savings which it expects to realise over the forecast period. These forecasts are described below.

The categories of cost include:

- Administration Costs – These costs include finance, administration, human resources, information technology and related support cost areas.

- Network Operations and Maintenance Costs – These include costs associated with the direct operation and maintenance of the Network. This includes activities such as maintenance planning and management, leak repairs, equipment maintenance, Metering, and odorisation of gas.

- Public Awareness and Marketing – These costs cover activities such as marketing to developers, promoting the safe use of gas and gas appliances, satisfying environmental concerns and developing additional gas usage and network utilisation through public awareness.

3.2 Total Costs

Forecast operating and maintenance costs for the five years to 31 July 2006 are summarised in Table 3.1 below. These costs include the impact of consumption growth over the period, and hence show real reductions in operating and maintenance costs.

Table 3.1: Network Operating and Maintenance Costs (excluding UAG) ($m Nominal)

Year Ending 30 June	01/02	02/03	03/04	04/05	05/06
Network Operation and Maintenance	6.1	6.4	6.7	7.1	7.3
Network Marketing Costs	0.4	0.4	0.4	0.4	0.4
Administration	1.4	1.4	1.4	1.4	1.4
Total Non-Capital Costs (excluding UAG)	8.0	8.2	8.5	8.9	9.1

Numbers may not add due to rounding.

These amounts do not include allowances for retail contestability costs, gas balancing costs or environmental works that may arise in the future, because these costs are presently beyond the control of Allgas. Retail contestability for example could result in very significant expenditures. However, until the extent and form of competition is understood by Allgas then it is impossible to predict expenditure. The principle of cost pass-through for these costs has been accepted by the Regulator. Allgas will apply to the Regulator at an appropriate time for the appropriate funding for such activities.

The operations of Allgas in regard to the access arrangement are the subject of agreements between Allgas and ENERGEX Limited. ENERGEX Limited is engaged as an independent contractor to operate and manage the Natural Gas Network and provide most support services. As a result, Allgas does not incur Operations and Maintenance expenditure on Wages and Salaries, Rental Equipment, Materials and Supply and Property Taxes. As all Operations and Maintenance costs are incurred by ENERGEX Limited, the total of Operating and Maintenance expenditure shown in the above table, represents costs of services provided by others. Note that all charges to Allgas have been charged at cost.

Marketing services will be performed by ENERGEX Limited under the above agreements. Advertising may include the name of the network service provider (presently Allgas), provided that this name is dissimilar to that of an associated retailer.

An examination of the nature of operations and maintenance costs indicates that costs are basically fixed and do not vary with throughput.

Gas fees are paid to the Queensland Government based on the level of gas sales volume with a rebate reduction for large usage customers. As gas fees are determined on the level of retail sales, it has been assumed that this charge is a retail charge and consequently, gas fees have not been included as part of the regulated Operating and Maintenance expenditure of the Network.

3.3 Regulated and Unregulated Costs

In determining the base revenue, costs were allocated between regulated and unregulated segments. Because various activities are ring-fenced, a large percentage of the operations and maintenance costs were directly attributable to the regulated business. Where costs were required to be apportioned, cost drivers based on the activities concerned were applied.

Unregulated services provided by Allgas are not subject to this Access Arrangement. An example of this is repair of the Network as a result of damage to the Network by a third party.

3.4 Unaccounted for Gas (UAG)

The following Sections describe the Allgas UAG forecasts.

3.4.1 Description and Forecast

Unaccounted for Gas (UAG) occurs due to a combination of leakage in pipes, Metering errors and accounting errors created by timing differences in Meter readings.

The Allgas Network has a significant amount of older cast-iron mains and accordingly leaks do occur. While it is recognised that leakage of gas is not desirable, Allgas cannot immediately justify the large capital expenditures that would be required to remove all cast-iron mains from service throughout the Network. Upgrade works to reduce UAG are driven by two factors. Firstly, any leak that constitutes a safety concern must be repaired in accordance with relevant legislation. Repairs or replacement of the relevant sections is always carried out in these instances. Secondly, for minor leaks that do not result in safety concerns, Allgas adopts the approach of optimising UAG so that End User prices are minimised. If UAG increases substantially and the cost of lost gas will begin to exceed the cost of repairs or replacement, then work is carried out to reduce the leakages.

Similarly, if the cost of ongoing repairs is excessive, then Allgas will carry out insertion or mains replacement to remove the offending mains. However, whether to continue to repair mains or replace sections of mains is an issue that is determined based on commercial/ economic criteria. Allgas has a mains replacement program in place and this is aimed at optimisation of outcomes for End Users, while maintaining the necessary safety standards. This mains replacement program results in the reduction of UAG over the term of the access arrangement as shown below. The implementation of this program is subject to commercial justification of each individual stage.

As compressors are not required at the present time on the Allgas Network there is no allocation of costs for compressor fuel.

The allowed costs of UAG are as shown in Table 3.2 below. It must be recognised that system use gas has to be firm (non-interruptible) and this costing has been derived from current contractual arrangements. These estimates can vary significantly from month to month due to variability of UAG volumes and also price structures in existing contracts that include fixed plus variable amounts.

Table 3.2: Forecast Costs of UAG ($m Nominal)

Year ending 30 June	01/02	02/03	03/04	04/05	05/06
Cost ($m)	1.3	1.4	1.5	1.6	1.7

The allocation of UAG costs to various End User classes is discussed in Section 9 below.

3.5 Ancillary Services

Allgas provides a number of ancillary services including the following.

- Special Meter Reading Service: for Meter readings other than scheduled Meter readings.
- Inlet Disconnection Service: physical disconnection of pipe-work joining a Delivery Point to the Network.
- Inlet Reconnection Service: physical reconnection of a Delivery Point – includes relighting any appliances installed at the place or premises to which gas is delivered through the Delivery Point under the Small Customer service.

Charges for these services are shown in the Access Arrangement's Appendix B: Tariff Schedule.

4 INITIAL CAPITAL BASE

The following Sections describe the determination of the initial capital base used in the Allgas revenue forecast.

4.1 Code Requirements

8.10 When a reference tariff is first proposed for a reference service provided by a covered pipeline which was in existence at the commencement of the Code, the following factors should be considered in establishing the initial capital base (Section 8.10):

(a) The value that would result from taking the actual capital cost of the Covered Pipeline and subtracting the accumulated depreciation for those assets charged to Users (or thought to have been charged to Users) prior to the commencement of the Code;

(b) The value that would result from applying the "depreciated optimised replacement cost" methodology in valuing the Covered Pipeline;

(c) The value that would result from applying other well recognised asset valuation methodologies in valuing the Covered Pipeline;

(d) The advantages and disadvantages of each valuation methodology applied under paragraphs a), (b) and (c);

(e) International best practice of Pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries;

(f) The basis on which Tariffs have been (or appear to have been) set in the past, the economic depreciation of the Covered Pipeline, and the historical returns to the Service Provider from the Covered Pipeline;

(g) The reasonable expectations of persons under the regulatory regime that applied to the Pipeline prior to the commencement of the Code;

(h) The impact on the economically efficient utilisation of gas resources;

(i) The comparability with the cost structure of new Pipelines that may compete with the Pipeline in question (for example, a Pipeline that may by-pass some or all of the Pipeline in question);

(j) The price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase; and

(k) Any other factors that the Relevant Regulator considers relevant.

4.2 DORC Methodology

Allgas submits that the Depreciated Optimised Replacement Cost (DORC) is the appropriate asset valuation methodology to be used in determining the initial capital base. Allgas has carried out significant analysis of alternative valuation methodologies. This analysis is referred to below.

The following are extracts from a report provided by Gutteridge Haskins & Davey Pty Ltd (GHD) who were employed by Allgas to conduct a DORC valuation on the Allgas Network.

A valuation was conducted using the Depreciated Optimised Replacement Valuation approach to ensure that:

- current customers do not bear the burden of tariffs for services loaded by valuation of unnecessary capacity built into systems such as the gas distribution Network. That is, the optimisation process sizes the system for a nominated demand related to current demand plus some forecast growth and eliminates over capacity historically built into many infrastructure systems;
- customers and organisations do not have to bear past inefficiencies involved in the staged development of long-lived infrastructure Networks. Optimisation enables valuers to optimise designs and disregard inappropriate or redundant assets; and
- 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 the age of the existing assets. The valuation is built up as the sum of the values of individual asset groups.

The application of the DORC approach involves the following:

i) Asset identification and selection of Modern Engineering Equivalence;

ii) Calculation of the replacement costs of the asset base;

iii) System optimisation;

iv) Determination of asset lives and calculation of depreciation; and

v) Calculation of the Depreciated Optimised Replacement Costs.

The DORC methodology involves the following steps.

Step 1: Establish Modern engineering Equivalent Network

A modern engineering equivalent ("MEE") is identified for each asset type. This represents what the asset would be replaced with now, given modern technology and accepted industry practices.

Step 2: Establish replacement cost

A standard replacement cost ("SRC") is established for each MEE. This is expressed per unit of length or quantity.

The application of the SRC to the MEE of each existing Distribution System asset provides a RC for that asset. When applied to the optimised system asset, this approach gives the optimised replacement cost ("ORC").

Step 3: Asset optimisation

Existing assets may be scaled down in size or removed altogether where the capacity they provide is not required or is materially in excess of what is required based on existing and forecast gas flows.

The valuation of the distribution system should be based on the optimised system for the purpose of tariff setting. It is necessary that such evaluation should pertain to the pipeline sizes required rather than those that presently exist. Where assets are over-capacity or over-designed, then this needs to be netted out. Where the existing capacity is under sized the limiting capacity should be adopted. The resulting DORC valuation reflects the cost of an efficient set of assets designed to achieve the required function.

For the purpose of the Allgas valuation, an optimised distribution Network built using modern construction methods and materials was considered. The following assumptions were also applied:

- the system complies with industry standards including standards for security of supply and is designed to pressure ratings consistent with industry best practice;
- capacity is adequate for existing customer demand and forecast customer demand (over a 5 year time horizon), where it is currently being oversized;
- the system supplies the same cities, towns and customers as are supplied by the existing system;
- supply boundaries are the same as for the existing system;
- the system meets current customer delivery or contract arrangements;
- the location of existing customers is not varied and number of customers is not increased; and
- the gas supply points to the Network are defined by the present transmission system.

4.2.1 Optimisation Standards

The optimisation standards adopted in the valuation are comparable to those of other gas utilities in Australia. The technical standards that are used for the design and construction of mains and services within Allgas have been grouped as follows:

Design of Allgas Distribution System

AS 1697	SAA Gas Pipeline Code
AS 4130 (1997)	Polyethylene (PE) pipes for pressure applications
AS 2885.1	Pipelines - Gas & Liquid Petroleum: Design & Construction
AS 2885.2	Pipelines - Gas & Liquid Petroleum: Welding
AS 2885.3	Pipelines - Gas & Liquid Petroleum: Operations and Maintenance
AS 3723	Installation & Maintenance of Plastic Pipe System for Gas
AS 4360/95	Risk Management
AG 603/78	Gas Distribution Code
AG 601/95	Gas Installation Code

Acts and Regulations

Gas Act 1965 – 1988

Gas Regulations – 1989

In addition, Allgas has formulated a series of work procedures to comply with the Occupational, Health and Safety requirements as well as with current Environmental Acts.

Optimisation also needs to take into consideration construction practicality. For example, due to low penetration and utilisation in some areas, a 25 mm diameter main may theoretically be necessary but a 40 mm diameter is the minimum practical main size as the industry standard. Also, the cost differentials between different diameter pipes at the lower size range are minimal.

The provision of 5-year planning horizon allows for the normal lead time required in an average engineering planning, procurement and construction environment.

4.2.2 Verification of Optimisation

Allgas Networks generally operate at two different pressures: the high pressure system and the low/medium pressure system.

High Pressure Systems

These are systems that operate at maximum allowable operating pressures (MAOP) of between 1,200 kpa and 7,000 kpa. The mains are mainly coated steel and are also cathodically protected. Nine high pressure systems, each associated with a particular gate station and with direct connection to the APT pipeline, have been identified.

<u>Brisbane Network</u>

- Doboy Gate Station
- Tingalpa Gate Station
- Ellengrove Gate Station
- Runcorn1 Gate Station
- Wishart Gate Station
- Dinmore Gate Station

<u>Oakey Network</u>

- Oakey Gate Station

<u>Toowoomba Network</u>

- Toowoomba Gate Station

<u>South Coast Network</u>

- Runcorn2 Gate Station

The high pressure systems supply gas to the low/medium pressure systems through the sub-gate stations and district regulators and to the major industrial consumers directly.

In optimising the Brisbane Network, the potential to introduce efficiency in the number of interfaces between the Network and the transmission pipeline and hence the number of gates and sub-gate stations was investigated.

As the optimisation is constrained to existing delivery points, the widely scattered customer base in the Brisbane Network does not present any opportunity for further optimisation without sacrificing the security of supply to the existing customers. Without the aid of any advanced computerised optimisation model Allgas carried out the preliminary optimisation process based on pressure drop constraints in the Network using an in-house validated spreadsheet.

In the optimisation process it was evident that, except for the Toowoomba Network which is currently under capacity, some pipeline diameters in other Networks were oversized and the optimised system reduces the pipe sizes accordingly to accommodate the current demand plus the projected demand for the next 5 years.

Low/Medium Pressure System

These are mains which mainly operate up to MAOP of 500 kpa and they are mainly of cast iron pipes, coated steel with no cathodic protection, and some PVC and PE in the newer development areas.

Optimisation has taken into consideration the following issues:

- redundant mains;
- duplicate mains; and
- pipe insertion opportunities.

The redundant mains have been netted out in the validation of the lengths of mains.

Duplicate mains (generally on opposite sides of a street) had been checked against the possibility of using a single main with thrust boring across the street for service connection in terms of cost savings. An analysis has been completed on sample areas for the Brisbane Network which generally has penetration ratios of 90% and 50% respectively for the metro and outer metro regions.

The analysis is summarised in Table 4.1 below.

Table 4.1: Cost Comparison between Duplicate Mains and Thrust Boring

Region	Ave % Duplication	% Cost Savings with Thrust Boring	Weighted Cost Savings %	% of Mains in Region
Metro	9.18	10.08	0.93	25
Outer	3.59	58.56	2.40	75
Brisbane Network Cost Saving				1.81%

The above cost savings have to be weighed against the likelihood of having a single larger main instead of duplicate mains.

Based on the above analysis for the Brisbane Network and considering the type of development for other Networks, Allgas believes that there is no opportunity for material cost savings from the optimisation of duplicate mains in its current brown fields condition.

There are limited opportunities for pipe insertion. For those inserted pipes in the current low and medium pressure area, the maximum operating pressure on inserted pipes can only be 200kpa because of the minimum cover requirements.

Approximately 50% of the existing cast iron and steel mains are currently laid in the middle of roads. It is not economically feasible to adopt pipe insertion as the replacement technique for these mains due to the high penetration of services and the unusually high costs involved in service connection, traffic diversion and road reinstatement etc. Allgas had also completed a field assessment of the feasibility of pipe insertion and the results indicated that 47% of these cast iron and steel mains are capable of being inserted.

The cost involved in pipe insertion for mains located in footpath is approximately 25% lower than the total replacement cost for the new main using open cut construction. The cost saving is only available for 47% of the existing cast iron materials due to the location constraints of these cast iron mains (too shallow). The cost savings are mainly derived from savings in trenching, traffic control and reinstatement. This figure is in line with industry estimates.

With the replacement of cast iron mains and Network modeling there is opportunity to introduce efficiency and reduce the number of sub gate stations.

Extent of Optimisation

A recommended criteria in any optimisation process is that it focuses on aspects likely to have a material impact on valuation.

The extent of the above optimisation process can be summarised as follows.

- Distribution mains: sizes reduced to accommodate efficiency of system development, capacity reduced if current system is over sized to suit current demand plus projected growth for the next five years. No reduction in lengths.
- Services: Existing services are replaced with modern engineering equivalent and current customers served.
- Gate stations: No reduction in numbers.
- Sub gate stations: Numbers reduced from 11 to 2.
- District Regulators: Numbers reduced from 265 to 236.
- Meters: No reduction in number or sizes. Current customers served.
- High Pressure Main to South Coast: capacity reduced to accommodate efficiency of system development, and to suit current demand plus projected growth for next five years.

Step 4: Depreciate the asset

Depreciation is based on a straight-line depreciation profile using a standard economic life (“SEL”) for each asset type, together with an estimate of the remaining life (“RL”) of each asset. Thus if an asset had a SEL of 40 years and a RL of 10 years, it would be depreciated to 25% of its replacement cost.

Depreciation applied to the RC or ORC of each asset gives the depreciated replacement cost ("DRC") and ODRC for each asset. Target revenue is based on the total ODRC of all assets used to provide reference distribution services

4.3 Depreciation

The following Section describes how depreciation has been determined for the capital base.

4.3.1 Code Requirements

8.32 The Depreciation Schedule 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 (the ***Depreciation Schedule****).*

8.33 The Depreciation Schedule should be designed:

(a) so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of the Reference Tariffs has assumed significant market growth and the Pipeline has been sized accordingly);

(b) so that each asset or group of assets that form part of the Covered Pipeline is depreciated over the economic life of that asset or group of assets;

(c) so that, to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the Covered Pipeline is adjusted over the life of that asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and

(d) subject to Section 8.27, so that an asset is depreciated only once (that is, so that the sum of the Depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the Capital Base, subject to such adjustment for inflation (if any) as is appropriate given the approach to inflation adopted pursuant to Section 8.5A).

4.3.2 Asset remaining lives

For the purposes of determining target revenues, individual asset categories were grouped together to calculate depreciation and return on assets. The lives for each of the asset groupings is set out in Table 4.2 below.

Table 4.2: Asset Lives

Asset		Lives (yrs)
Mains and Services		
	Cast Iron	80
	Steel - protected - unprotected	105 45
	PVC PE Copper	30 80 85
Meters		
	M1 (Domestic/Commercial)	25
	M2 to M5 (Commercial/Industrial)	30
Gates/Subgates		50
District regulators		50

4.3.3 Depreciation Calculation

Allgas has utilised a straight-line approach in the determination of depreciation for the capital base. The straight-line approach is appropriate since:

- depreciation is allocated according to the expectation of assets' usage over the economic life of the assets;
- depreciation is stable over the life of the assets and therefore will not result in price shocks;
- it is simple, transparent and readily determined; and
- it is widely used and accepted throughout the gas industry and other regulated industries.

The depreciation using this approach is summarised in Table 4.3 below.

Table 4.3: Depreciation Summary

Asset	Annual Depreciation $ (99/00)
Mains	2,019,055
Services	849,390
Regulator Stations	132,945
Meters	617,673
Non-system	576,443
Depreciation on 99/00 Capex	48,222
Total	4,243,728

4.3.4 Future Depreciation

Future year depreciation is determined by taking the base year depreciation, escalating this for asset indexation as appropriate and then adding depreciation associated with capital expenditure. The resulting annual depreciation projections are as shown in Table 4.4 below:

Table 4.4: Future Depreciation ($m Nominal)

Year ending 30 June	01/02	02/03	03/04	04/05	05/06
Depreciation	4.7	5.1	5.2	5.3	5.6

4.4 Summary of Valuation

4.4.1 Valuation of System Assets

Based on the methodology adopted, the processes followed and the available data, the Depreciated Optimised Replacement Value of the Allgas system assets has been set at $180.5 million as at 30 June 1999.

The optimised replacement cost is just over $4 million lower than the replacement cost of the existing system (i.e. 98% of the latter), reflecting the near optimality of the current Network.

The accumulated depreciation for the optimised system is about $60 million, which is 25% of the optimised replacement value.

4.4.2 Valuation of Non-system Assets

The current book values for vehicles and plant and equipment have been utilised by Allgas while the value of land and buildings was established by an independent market valuation as at 31 December 1999.

The results of the valuation of non-system assets are summarised in Table 4.5 below.

Table 4.5: Non-System Assets ($m)

Non system assets	As at 30 June 00
Land and buildings	2.5
Vehicles	0.7
Sundry plant and equipment	1.2
Total non system assets	4.4

4.4.3 Summary – Initial Capital Base

Table 4.6 below summarises the total initial capital base.

Table 4.6: Summary of Initial Capital Base ($m)

Asset	As at 1 July 01
System	198.2[1]
Non-system	4.4
Total	202.6

4.5 Advantages of DORC

The Depreciated Optimised Replacement Cost valuation method has become the favoured method of valuation under the ACCC's Draft Statement of Principles for the Regulation of Transmission Revenues. DORC has a number of highly attractive features, including the fact that it represents the best proxy for asset costs which a competing alternative infrastructure provider would face. For networks which will need to be replaced in the future, DORC also ensures that regulated revenues will be sufficient to fund the replacement without imposing price shocks on customers.

The DORC valuation has been widely supported in practice in asset valuations in Australia including the following:

- DORC was used as the basis for valuing the Victorian electricity businesses and gas businesses before privatisation;
- the ACCC's approach to telecommunication regulation is based on a cost basis of Total Long Run Incremental Cost which is based on costs using the best-in-use technology and production practices and valuing inputs using current prices; and
- the Queensland Electricity Reform Unit used DORC for the valuation of the electricity businesses in Queensland for the purposes of conformance with the National Electricity Code.

The ACCC has recently adopted the DORC valuation methodology for application to electricity transmission assets:

> *" Given the above considerations the Commission has decided to adopt the DORC valuation methodology as the approach it will use to set the cap on the valuation of the asset base. In adopting the DORC methodology the Commission has been guided by submissions received in response to the Regulation of Transmission Revenues Issue Paper. The Commission has also noted the interest of the accounting profession in exploring market related approaches to valuation as a basis for mainstream reporting purposes and management accounts*"[2]

The QCA has also applied the DORC valuation method in its regulatory decisions with respect to rail and electricity.

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[1] The system assets have been "rolled" forward to 1 July 2001.

[2] Australian Competition and Consumer Commission, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p.41.

5 WEIGHTED AVERAGE COST OF CAPITAL (WACC)

5.1 Code Requirements

8.30 The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).

8.31 By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing Model. 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 Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in Section 8.1.

5.2 Rate of Return Applied

Allgas has applied a post-tax nominal WACC of 9.27% to a Depreciated Optimised Replacement Cost asset base to derive the return on capital component of the Revenue Building Block formula.

Details of the approach and input assumptions are discussed in the Sections below.

5.3 Approach to WACC Determination

In determining the return on capital, Allgas has applied the Weighted Average Cost of Capital model (WACC), using the Capital Asset Pricing Model (CAPM) to determine a return on equity.

5.3.1 WACC Formula and Relevant Cash Flows

The different forms of WACC that are commonly used as regulatory targets are as follows:

	WACC Formula	***Cash Flow***
WACC 1 (Officer WACC)	$\frac{Ke\,(1 - Tc)}{(1 - Tc\,(1 - y))} * \frac{E}{V} + Kd(1-Tc) * \frac{D}{V}$	$X_o * (1-Tc)$
WACC 2	$Ke * \frac{E}{V} + Kd * (1 - Tc\,(1 - y)) * \frac{D}{V}$	$X_o * (1-Tc * (1 - y))$
WACC 3 (Vanilla WACC)	$Ke * \frac{E}{V} + Kd * \frac{D}{V}$	$X_o - (X_o - X_d) * Tc * (1-y)$
WACC 4	$Ke * \frac{E}{V} + Kd * (1 - Tc) * \frac{D}{V}$	$X_o * (1 - Tc) + Tc * y * (X_o - X_d)$

WACC 3 has been applied in the calculation of the cost of capital for this Access Arrangement. This form of WACC is an estimate of the total return that the asset owners demand, and requires all tax effects (including imputation) to be reflected in the cash-flows.

5.4 Derivation of the WACC Input Assumptions

5.4.1 Return on Equity (Ke)

The return on equity is the return that investors require for the level of risk associated with their investment.

Currently, the best approach for measuring the required return to equity holders is the Capital Asset Pricing Model (CAPM). This approach has also been consistently used in other regulatory decisions throughout Australia.

The Capital Asset Pricing Model (CAPM) formula is stated as:

$$Ke = Rf + Be*(Rm - Rf)$$

where:

Ke	=	Cost of equity / return that equity holders require
Rf	=	Risk free rate of return
Rm – Rf	=	Market risk premium
Be	=	Equity Beta

Each of the inputs to the CAPM formula is discussed below.

5.4.2 Risk Free Rate (Rf)

The risk free rate is the rate that an investor would receive from an investment with no, or virtually no, risk. Australian Commonwealth bonds have long been considered by corporate finance practitioners as an appropriate estimate of the risk free rate.

Allgas has adopted the 10 year nominal Commonwealth bond as an appropriate measure of the risk free rate on the basis that:

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

.Allgas has applied a risk free rate of 5.96% based on the 20 trading day average of the 10 year Commonwealth Bond rate commencing 11 June 2001.

5.4.3 Market Risk Premium (MRP)

The market risk premium represents the additional return over the risk-free rate that an investor would require as compensation for the risks of investing in a well-diversified equity portfolio.

Measurement of the market risk premium is a contentious issue with numerous academic studies having been undertaken in the last fifteen years. These studies are summarised in the following table.

Table 5.1: Market Risk Premium Studies

Source	Period	Risk Premium %
AGSM	1964 – 1995	4.1 – 8.1
Officer	1946 – 1991	6.0 – 6.5
Officer (1989)	1900 – 1996	7.1 – 5.4
Hathaway (1996)	1882 – 1991	7.7
Hathaway (1996)	1947 – 1991	6.6

Clearly the Market Risk Premium cannot be measured with precise accuracy. Market practitioners generally apply a MRP in the range of 5.0% to 7.0% in assessing investments.

After having regard for the academic studies and market practice, Allgas has adopted a market risk premium of 6.0% based on the mid-point of the generally accepted range for the risk premium.

5.4.4 Equity Beta (Be)

The equity beta represents the sensitivity of an asset to changes in the value of the market portfolio. The equity beta therefore measures systematic or market risk reflecting variations in earnings or cash flows in line with movements in overall market or macroeconomic factors. These are risks that cannot be eliminated through diversification. The equity beta is derived from the underlying asset beta adjusted for gearing.

5.4.5 Asset Beta (Ba)

The asset beta measures the underlying market risk of the asset. An appropriate range can be determined by reference to the equity beta for listed firms that are considered to have a comparable degree of systemic risk and then adjusting for their capital structure.

Asset betas identified in recent regulatory reviews and those used in regulatory decisions are listed below:

Table 5.2: Asset Betas Used in Recent Regulatory Reviews

Regulator	Decision	Date	Company	Asset Beta Range	Asset Beta Applied
IPART	Final	Sep-00	AGL Gas Networks Ltd	0.4 - 0.5	0.4 – 0.5
OFFGAR	Final	Jun-00	AlintaGas	0.45 – 0.60	0.55
IPART	Final	Dec-99	Albury Gas Company	0.40 – 0.50	0.4 – 0.5
IPART	Final	Sep-99	Great Southern Network	0.50 – 0.50	0.4 – 0.5
ACCC	Draft	Sep-99	AGL Central West Pipeline	0.60	0.60
ACCC	Final	Oct-98	TPA	0.45 – 0.60	0.55
ORG	Final	Oct-98	Victorian Gas Distribution	0.45 – 0.60	0.55
Ofgas/MMC	Final	May-97	Transco	0.45 – 0.60	0.45 – 0.60

Based on the above asset betas for comparable companies, Allgas considers that a reasonable estimate of the asset beta is in the range of 0.40 to 0.60 for an Australian gas distribution business.

Allgas has applied an asset beta of 0.55. The basis for this selection is that Allgas is subject to a higher level of underlying risk than its Southern counterparts, as:

- Allgas' market penetration is far less than the Victorian gas distributors, and the annual average gas consumption for residential gas customers is far less than that of gas distributors in the Southern States;
- the average price of gas for domestic and industrial customers in Queensland is higher than for gas distributors in NSW and Victoria. This can lead customers to substituting a cheaper energy source such as electricity; and
- on current price relativities, Allgas is far more reliant upon the revenue from industrial customers than the Victorian gas distributors. As these customers are more likely to respond to market-wide movements, this should increase the level of systematic risk.

5.4.6 Equity Beta Adopted

Allgas has adopted an equity beta of 0.99 based on an asset beta of 0.55.

Equity betas adopted in recent decisions are as follows.

Table 5.3: Equity Betas from Recent Regulatory Reviews

Company	AGL Gas Networks Ltd	AlintaGas	Albury Gas Company	TPA
Regulator	IPART Final Decision Sep-00	OFFGAR Final Decision Jun-00	IPART Final Decision Dec-99	ACCC Final Decision Oct-98
Be	0.90 – 1.10	1.08	0.90 – 1.10	1.20
Be using Officer conversion formula	0.91 –1.16	1.08	0.91 –1.16	1.20

5.4.7 Cost of Equity (Ke) Applied

In determining the Real Pre-Tax WACC to be applied to the Regulatory Asset Base, Allgas has applied a Nominal Post Tax Cost of Equity of 11.9% based on:

- the CAPM formula Ke = Rf + Be*(Rm - Rf);
- a risk free rate of 5.96%;
- an Equity Beta of 0.99; and
- a Market Risk Premium of 6.0%.

For comparative purposes, equity returns implicit in recent regulatory decisions are as follows.

Table 5.4: Equity Returns in Recent Regulatory Reviews

Company	AGL Gas Networks Ltd	AlintaGas	Albury Gas Company	TPA
Regulator	IPART Final Decision Sep-00	OFFGAR Final Decision Jun-00	IPART Final Decision Dec-99	ACCC Final Decision Oct-98
Ke (Nominal Post-Tax)	10.9 – 13.0	12.75	11.2 – 13.3	13.20

5.4.8 Cost of Debt (Kd)

The cost of debt is derived using the risk free rate plus a premium for borrowing costs:

Kd = Rf + Dp

Where:

Kd = Cost of Debt

Rf = Risk Free Rate

Dp = Debt Premium

The debt premium reflects the duration of the funding, the credit rating of the borrower and the degree of gearing of the business.

Allgas Energy Limited is currently funded through an inter-company facility provided by its parent company ENERGEX Limited. The funding arrangements currently in place reflect internal arrangements that are not relevant for determining an appropriate debt premium or gearing structure for regulatory purposes.

In determining an appropriate debt premium, Allgas maintains the premise that the WACC should be a benchmark return and any input into the WACC should also be based on benchmarks.

A stand-alone regulated gas network would likely be rated at BBB to A- given the level of gearing proposed and the relative risk inherent in the cash flows. Based on these ratings debt would be in the range of 135-200 bp. Allgas has selected a point within this range at 155 bp as an appropriate benchmark rate.

Allgas has therefore applied a cost of debt of 7.51% based on adding a debt risk premium of 1.55% to the risk free rate, determined earlier as 5.96%.

For comparative purposes the Cost of Debt and Debt Premiums applied in recent regulatory decisions are shown in the following table:

Table 5.5: Cost of Debt in Recent Regulatory Reviews

Company	AGL Gas Networks Ltd	AlintaGas	Albury Gas Company	TPA
Regulator	IPART Final Decision Sep-00	OFFGAR Final Decision Jun-00	IPART Final Decision Dec-99	ACCC Final Decision Oct-98
Dp (%)	0.90 – 1.10	1.20	0.90 – 1.10	1.20
Kd (%) (Nominal Pre-Tax)	7.34 - 7.54	7.47	7.55 - 7.75	7.20

5.4.9 Tax Rate (Tc)

Allgas has adopted a tax rate of 30% consistent with the long-term expectation of tax rates. This rate has been used in determining forecasts for the cost of tax for each year of the regulatory period, which have been included in the cash flows.

5.4.10 Imputation Rate (y)

The value that the average investor attributes to each dollar of franking credits received is referred to as ‘gamma’ or the imputation rate.

Under Australia’s imputation system, domestic equity investors receive a franking credit that is attached to any dividends paid out of after-tax company profits. This franking credit may be used to offset the personal tax of the investor, and therefore represents additional cash flow to the investor.

The potential average value that may be attributed to imputation credits depends on:

- the ability of the average shareholder to utilise the credits; and
- the rate at which the average company distributes imputation credits.

Allgas has assumed an Australian private ownership assumption when considering the value of imputation credits on the basis that:

- the assumption is consistent with the approach taken by other State and National Regulators;
- it avoids inter-regional price variations; and
- it avoids inter-generational price variations caused by potential privatisations or asset sales.

On this basis, Allgas believes that the best current estimate of imputation credits to be in the range of 40% - 60% and has applied the mid-point of this range at 50% in determining the cash flows for the business over the regulatory period.

Table 5.6: Imputation Rates applied in Recent Regulatory Reviews

Company	AGL Gas Networks Ltd	AlintaGas	Albury Gas Company	TPA
Regulator	IPART Final Decision Sep-00	OFFGAR Final Decision Jun-00	IPART Final Decision Dec-99	ACCC Final Decision Oct-98
Imputation (%)	30% - 50%	50%	30% - 50%	50%

5.4.11 Inflation (CPI)

An estimate of inflation is required for the transformation of nominal rates of return to real rates of return. A long-term estimate of inflation has been determined using the following two methods:

(a) Nominal Bonds vs Inflation Indexed Bonds

An inflation estimate can be determined by reference to the difference in the nominal bond rate and inflation indexed bond rate for the same term. As the risk free rate has been measured as the 20 day moving average it is necessary to apply the same averaging to the indexed bond rate.

The inflation rate can be then be derived using the Fisher equation:

$$\text{Inflation rate} = (1 + X_{nominal}) / (1 + X_{real}) - 1$$

where:

$X_{nominal}$ = Risk Free Rate of 5.96%

X_{real} = 20 day average Indexed Bond Rate of 3.30%

Based on the above formula the implied interest rate is 2.58%.

(b) CPI forecasts from Economic forecast agencies

Forecasts of CPI expectations have been obtained from a number of economic agencies. A summary of their forecasts is listed below:

Table 5.7: CPI Forecasts

Agency	Forecast Period	Average
Access Economics	01/02 to 08/09	2.50%
Econotech	01/02 to 08/09	2.30%
NIEIR	01/02 to 04/05	3.0%
Queensland Treasury Corp.	01/02 to 05/06	2.50%
Reserve Bank of Australia	Long Term	2.50%

Based on the implied inflation rate calculated from the nominal and indexed bonds, and forecasts from economic agencies, Allgas has selected an inflation rate of 2.50%. This rate is comparable with inflation rates applied in recent regulatory decisions.

Table 5.8: Inflation Rates Used in Recent Regulatory Reviews

Company	AGL Gas Networks Ltd	AlintaGas	Albury Gas Company	TPA
Regulator	IPART Final Decision Sep-00	OFFGAR Final Decision Jun-00	IPART Final Decision Dec-99	ACCC Final Decision Oct-98
Inflation (%)	2.83	2.78	3.00	2.50

5.4.12 Gearing (D)

The level of gearing is required to:

- identify a beta factor to estimate the cost of equity; and
- establish the appropriate weighted average cost of debt and cost of equity in WACC.

Allgas has assumed a capital structure of 60% debt and 40% equity, which is consistent with recent decisions for regulated gas and electricity businesses.

Gearing applied in recent regulatory decisions is shown in the following table.

Table 5.9: Gearing Ratios Used in Recent Regulatory Reviews

Company	AGL Gas Networks Ltd	AlintaGas	Albury Gas Company	TPA
Regulator	IPART Final Decision Sep-00	OFFGAR Final Decision Jun-00	IPART Final Decision Dec-99	ACCC Final Decision Oct-98
Gearing (%)	60%	60%	60%	60%

5.5 WACC Calculation

Applying the above inputs results in the following returns:

Table 5.10: Summary of WACC parameters

Parameter	Result
Risk Free Rate	5.96%
Market Risk Premium	6.00%
Debt Margin	1.55%
Equity Beta	0.99
Gamma	0.5
Tax Rate	30%
Debt/Equity	60%
Inflation	2.50%
Cost of Equity	11.9%
Cost of Debt	7.51%
WACC (post-tax nominal)	9.27%

6 CAPITAL EXPENDITURE

The following Section provides details of the Allgas capital expenditure program.

6.1 Code Requirements

8.15 The Capital Base for a Covered Pipeline may be increased from the commencement of a new Access Arrangement Period to recognise additional capital costs incurred in constructing New Facilities for the purpose of providing Services.

*8.16 The amount by which the Capital Base may be increased is the amount of the actual capital cost incurred (**New Facilities Investment**) provided that:*

(a) that amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services; and

(b) one of the following conditions is satisfied:

(i) the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or

(ii) the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or

(iii) the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

8.17 For the purposes of administering Section 8.16(a), the Relevant Regulator must consider:

(a) whether the New Facility exhibits economies of scale or scope and the increments in which Capacity can be added; and

(b) whether the lowest sustainable cost of delivering Services over a reasonable time frame may require the installation of a New Facility with Capacity sufficient to meet forecast sales of Services over that time frame.

*8.18 A Reference Tariff Policy may, at the discretion of the Service Provider, state that the Service Provider will undertake New Facilities Investment that does not satisfy the requirements of Section 8.16. If the Service Provider incurs such New Facilities Investment, the Capital Base may be increased by that part of the New Facilities Investment which does satisfy Section 8.16 (the **Recoverable Portion**).*

*8.19 The Reference Tariff Policy may also provide that an amount in respect of the balance of the New Facilities Investment may subsequently be added to the Capital Base if at any time the type and volume of services provided using the increase in Capacity attributable to the New Facility change such that any part of the Speculative Investment Fund (as defined below) would then satisfy the requirements of Section 8.16. The amount of the **Speculative Investment Fund** at any time is equal to:*

(a) the difference between the New Facilities Investment and the Recoverable Portion, less any amount the Service Provider notifies the Relevant Regulator (at the time the expenditure is incurred) that it has elected to recover through a Surcharge under

*Section 8.25 (**Speculative Investment**); plus*

(b) an annual increase in that amount calculated on a compounded basis at a rate of return approved by the Relevant Regulator which rate of return may, but need not, be different from the rate of return implied in the Reference Tariff; less

(c) any part of the Speculative Investment Fund previously added to the Capital Base under this Section 8.19.

8.20 Consistent with the methodologies described in Section 8.4, Reference Tariffs may be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement Period provided that the New Facilities Investment is reasonably expected to pass the requirements in Section 8.16 when the New Facilities Investment is forecast to occur.

8.21 If the Relevant Regulator agrees to Reference Tariffs being determined on the basis of forecast New Facilities Investment, this need not (at the discretion of the Relevant Regulator) imply that such New Facilities Investment will meet the requirements of Section 8.16 when the Relevant Regulator considers revisions to an Access Arrangement submitted by a Service Provider. However, the Relevant Regulator may, at its discretion, agree (on written application by the Service Provider) at the time at which the New Facilities Investment takes place that it meets the requirements of Section 8.16, the effect of which is to bind the Relevant Regulator's decision when the Relevant Regulator considers revisions to an Access Arrangement submitted by the Service Provider. For the purposes of public consultation, any such application must be treated as if it were a proposed revision to the Access Arrangement submitted under Section 2.28.

8.22 For the purposes of calculating the Capital Base at the commencement of the subsequent Access Arrangement Period, either the Reference Tariff Policy should describe or the Relevant Regulator shall determine when the Relevant Regulator considers revisions to an Access Arrangement submitted by a Service Provider, how the New Facilities Investment is to be determined for the purposes of Section 8.9. This includes whether (and how) the Capital Base at the commencement of the next Access Arrangement Period should be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives in Section 8.1).

6.2 Drivers of Capital Expenditure

The following key drivers of capital expenditure have been identified by Allgas:

- Customer Driven Works – these are works associated with new or upgraded connections for customers. These works include mains laying, service and Metering installations and miscellaneous other works.

- Network Augmentation works – these are works required to augment the existing system to ensure that safety, environmental and other service standards are maintained. This work includes mains replacement, new mains, regulator and gate station upgrades, telemetry works and miscellaneous other works.

- Mains Renewal Programs – these are major renewals programs to replace or insert existing mains where the existing mains need to be replaced generally due to ageing and / or unacceptable UAG levels.

- Non-system asset expenditure – these are additional assets required to carry out the management of the gas Network. These assets include land, vehicles, plant and various equipment (eg. PCs and IT systems).

Allgas has not undertaken a full-scale mains renewals program to date to replace sections of ageing cast-iron and steel mains. Some parts of the Network have been renewed but many parts have not. A mains renewal program has been factored into the capital expenditure program.

6.2.1 Summary of Capital Expenditure

Table 6.1 below is a summary of capital expenditure for Allgas.

Table 6.1: Capital Expenditure Summary ($m Nominal)

Year ending 30 June	01/02	02/03	03/04	04/05	05/06
Customer Requested	5.5	5.0	5.2	5.3	5.5
Augmentation	2.9	2.8	0.6	0.6	0.6
Network Renewal	5.1	4.5	4.6	4.7	4.8
System Total	13.5	12.2	10.4	10.6	10.9
Non-System	0.3	0.3	0.3	0.3	0.3
Total Capital Expenditure	13.8	12.5	10.7	11.0	11.2

Numbers may not add due to rounding.

7 REVENUE FORECAST

7.1 Asset Roll Forward

The asset value is calculated as follows:

Opening asset value$_n$ – Depreciation$_n$ – Disposals$_n$ + Inflation revaluation + Capex$_n$ = Closing asset value

The asset values for revenue determination in each year are as detailed in Table 7.1 below.

Table 7.1: Closing Asset Base Summary ($m Nominal)

Year ending 30 June	00/01	01/02	02/03	03/04	04/05	05/06
Asset base	202.6	216.9	229.9	241.1	252.9	264.9

In determining the asset value to be used in calculating total revenue for any given year, the following calculation has been applied:

Total Revenue = Return on Assets$_n$ – Change in asset base$_n$ + Depreciation$_n$ + Opex$_n$ + Unaccounted for gas$_n$ + Tax$_n$ – Franking Credits$_n$

where:

Return on Assets = WACC * (Closing asset base$_{n-1}$ – 0.5 * Depreciation$_n$ + 0.5 * Capex$_n$)

Change in asset base = CPI$_n$ * (Closing asset base $_{n-1}$ – 0.5 * Depreciation$_n$ + 0.5 * Capex$_n$)

7.2 Target revenue summary

Raw target revenues for the five year period are summarised in Table 7.2 below.

Table 7.2: Revenue Summary ($m Nominal)

Year ending 30 June	01/02	02/03	03/04	04/05	05/06
Return on assets	14.3	15.2	16.0	16.8	17.6
Depreciation	4.7	5.1	5.2	5.3	5.6
Opex	8.0	8.2	8.5	8.9	9.1
Unaccounted for gas	1.3	1.4	1.5	1.6	1.7
Tax (after accounting for franking credits)	0.9	1.0	1.2	1.4	1.6
Target Revenue	29.2	31.0	32.6	34.0	35.7

7.3 Smoothing

The raw target revenues imply lumpy price changes from year to year. This is because the cost levels fluctuate from year to year and there is not a smooth progression of costs. It is desirable to smooth the prices over the access arrangement period to ensure that prices can be similarly transitioned over the period. Allgas has smoothed using a Net Present Value (NPV) approach to arrive at the following revenue forecasts.

The revenues derived from the smooth price path and energy forecasts are detailed in Table 7.3 below.

Table 7.3: NPV Smoothed Revenue ($m Nominal)

Year ending 30 June	01/02	02/03	03/04	04/05	05/06
Target Revenue	29.2	30.7	32.4	34.2	36.1

8 DEMAND FORECASTS

This Section describes the process by which the Allgas demand forecasts have been developed and then details the actual forecasts for the five year access arrangement.

8.1 Assumptions

The five year forecasts of gas demand in the Allgas region are based on the following assumptions on the Queensland economy and developments in the Australian and Queensland gas markets.

8.1.1 Queensland Economy

Real Gross State Product (GSP) in Queensland grew by 4.7% in 1998/99 and is expected to be around 4.2% for 1999/00. It has averaged over 4.5% in the last 10 years and consistently been around 1% above Australian Gross Domestic Product. GSP is expected to slow in 2001 then gradually pick up as an upturn in the construction and manufacturing sectors will drive the Queensland economy from 2002/03. GSP is expected to average over 4% towards the end of the decade and will continue to remain above Australian GDP growth.

Queensland population growth was only 1.7% in 1998/99 and 1999/00 as interstate migration declined to 22,000 and it is expected to remain at these relatively low levels for the next couple of years. However, it should be noted that population growth in South-East Queensland has been 2.2% during this period.

From 2002/03, it is expected that the economic slowdown in southern states and the improvement in the Queensland economy should increase interstate migration to Queensland and therefore increase population growth. The flow-on effects are an increase in the demand for dwellings and gas connections.

Table 8.1: Economic Indicators

	98/99	99/00	00/01	00-05	05-10
GSP (%)	4.7	4.2	3.0	3.7	4.2
Qld Pop. Growth(%)	1.70	1.75	1.80	1.90	2.00
Qld Population (M)	3.52	3.58	3.64	3.93	4.34

8.1.2 Australian and Queensland Gas Market

In 1973/74, natural gas held a 6.6 per cent share of the national energy market but by 1996/97, this share had risen to 17.5 per cent. This large increase has primarily been due to:

- expansion of gas pipelines and resultant gas distribution;
- an increase in natural gas supply;
- capital investment in industry and electricity generation using gas; and
- the environmental advantages of natural gas and subsequent government encouragement of its use.

At present, the Queensland gas market consumes about 6 per cent of Australia's natural gas and a comparison of Australia and Queensland's split-up of natural gas consumption between sectors is shown in Table 8.2.

Table 8.2: Gas Consumption 1996/97

	Australia (%)	Queensland (%)
Industrial	61	88
Residential	15	3
Electricity generation	18	5
Commercial	6	3

As shown above, gas consumption in Australia is dominated by the industrial sector. This is especially true in Queensland where it consumes almost 90 per cent of final gas demand while the residential sector only has a 3 per cent share. Two large industrial customers constitute almost 70% of the gas demand in the Queensland industrial sector but their gas is purchased directly from producers not through the gas utilities. In reality, only 25% of gas sales in Queensland are delivered through the utilities.

According to NIEIR[3] (1999), the demand for gas in Queensland is projected to rise by around 18 per cent per annum until 2005 followed by average growth of 6.7%. It is estimated to be almost 250 PJ by 2010. ABARE[4] energy forecasts (1999) predict an even larger increase in gas demand up to 2004/05 (19.3%) but with volume growth easing to 3.4% in the years following.

Table 8.3: Queensland Gas Forecasts to 2015

	1996/97 PJ	2004/05 PJ	Growth per year (1997-2005) (%)	2014-15 PJ	Growth per year (2005-2015) (%)
NIEIR[8] (1999)					
Residential	1.1	2.4	12.4	3.0	2.3
Commercial	1.3	2.1	6.2	3.5	5.2
Industrial	41.4	73.7	7.5	138.0	6.5
Electricity Generation	2.3	90.7	58.3	178.1	7.0
NGV	0.2	1.7	30.6	4.4	10.0
Other	0.8	2.4	14.7	4.1	5.5
Total	47.1	173.0	17.6	331.1	6.7
ABARE(1999)					
Total	47.1	193.8	19.3	270.1	3.4

3 NIEIR (National Institute of Economic and Industry Research (1999), Medium Term Energy Sector Forecasts, Unpublished Papers

4 ABARE (Australian Bureau of Agricultural and Resource Economics) (1999), Australian Energy, Market Developments and Projections to 2014-15.

8.1.3 New Gas Sources

There are several possible alternative supplies of gas for Queensland that may come on-stream during the next five years. These include the mooted pipelines from Papua New Guinea and the Timor Sea, as well as increased production of coal seam methane in central Queensland.

Any of these options has the potential to significantly increase the supply of gas to Queensland. This will encourage the development of energy intensive industries and gas-powered electricity generation in the region. Furthermore, the lower expected cost of this gas could substantially increase the relative price advantage of gas over other energy substitutes.

Although much of any increased gas supply is likely to be absorbed by large industries and generators, ACIL (2000) believe that additional supplies of gas and subsequent lower prices could increase gas usage in South East Queensland by up to 30 PJ. Most of these sales will be independent of Brisbane gas utilities.

For these demand projections, it is assumed that a new source of gas will be available by 2003/04 and the lower gas prices will increase fuel switching to natural gas in major plants and for some commercial sites. This will increases Allgas' gas deliveries to the commercial and industrial sectors.

8.1.4 Industrial Sector

Growth in industrial gas demand in Australia is strongly tied to the level of economic activity as the elasticity of industrial gas demand to economic activity (ie. how much gas demand will deviate with a 1 per cent change in economic activity) is estimated to be slightly below unity in all Australian states (NIEIR[5] 1998).

Furthermore, it is assumed that firms will adjust production levels, within their plant capacity and cost restraints, so supply will meet the change in demand.

Growth will continue as open access arrangements and the removal of cross subsidies result in downward pressure on industrial natural gas prices. Industrial demand in Queensland is expected to follow a similar profile to the macro-economic projections for the state.

8.1.5 Commercial Sector

The commercial sector utilises natural gas for cooking, hot water, steam raising and heating. Growth in natural gas demand in the commercial sector in Australia has been steady despite the focus on energy efficiency. The use of additional equipment and the continual deregulation of business hours, especially in the retail trade area have been major drivers along with population growth and economic activity.

In the commercial sector, competition between gas and electricity is a major determinant of market share. It is likely to intensify in the future as a result of microeconomic reforms being implemented (deregulation of the respective markets) and major new infrastructure developments.

At the present, there are limited possibilities for substitution of natural gas for electricity in many commercial applications. Areas where natural gas has a demonstrated price advantage are in

[5] NIEIR (National Institute of Economic and Industry Research (1998), Medium Term Energy Sector Forecasts, Unpublished Papers

small-scale co-generation in hospitals, new or improved gas technology in space heating and cooling, and the traditional markets of water heating and cooking. However, new technologies for the use of natural gas in air conditioning represent the greatest market opportunities for natural gas. The demand for natural gas by the commercial sector in Queensland is forecast to grow steadily and increase its market share.

8.1.6 Residential Sector

Natural gas consumption in Australia has increased by 3.5 per cent per annum in the residential sector over this decade. In South-East Queensland, the increase has been approximately 2.6 per cent per annum.

Residential gas consumption in Australia is concentrated in the southern states which have high gas availability through the gas pipeline Network and where it is largely driven by the high penetration of gas heating appliances and cooler climates. In particular, Victorian households account for more than two thirds of total Australian residential gas consumption.

Table 8.4 shows the northern states of Queensland and the Northern Territory have a large percentage of households with no heating and the households with heating rely on electricity when it is present.

Table 8.4: Principal Forms of Heating in Households by State (%) – 1994

Form of heating	NSW	Victoria	QLD	WA	SA	NT	ACT	Australia
Gas	19.7	71.0	3.0	32.1	33.3	5.4	46.2	31.9
Electric	46.3	12.5	26.6	17.1	36.0	8.8	37.8	29.7
Wood	17.1	14.0	10.1	31.6	19.0	1.2	10.2	17.6
Oil	3.5	1.3	3.7	3.9	4.2	1.5	4.5	3.1
Other	1.8	0.6	2.0	2.1	1.5	1.3	0.9	1.5
None	11.7	0.6	54.6	13.2	5.9	81.8	0.4	16.2

Source: AGA (1996).

In Australia, residential demand for natural gas is growing as pipeline coverage increases and population increases occur. Growth in the sector is forecast to be slow in line with slower growth in the number of households and household income, the use of more energy efficient appliances and the increased use of insulation.

Although household gas usage is low in South-East Queensland, the higher population growth and relative newness of many of the gas pipelines are expected to keep residential gas consumption growth equal with the Australian average.

8.2 Allgas Gas Demand

Allgas is one of the major distributors of natural gas to South East Queensland, distributing almost 70% of Queensland's 14 PJ in gas deliveries by utilities.

The Allgas distribution pipelines are established in Brisbane, the South Coast and the Toowoomba and Oakey regions. These regions are considered separately for demand projections due to their distinct demographics, population growth and regionally based industries.

8.2.1 Brisbane

Brisbane has a total population of over 1.3 million people and average population growth of over 2 per cent.

The Allgas natural gas distribution pipelines are in South Brisbane and are well established. With the aged pipelines already in place, Allgas relies on new industry as well as increased urban population and increased market penetration for volume growth.

There are approximately 75 large accounts with gas consumption over 10,000 GJ per annum. The gas load of these large industrial accounts is expected to grow in line with the Queensland economy. However, the price impact of the new gas sources is expected to provide a boost to both industrial and commercial gas deliveries.

There are almost 1,500 small industrial and commercial customers in Brisbane and they account for approximately 11 per cent of the total gas volume. As with the other large industrial accounts, gas volume for this sector is dependent on the Queensland economy and population. The future gas volumes of these customers are expected to have higher growth from 2004-10 as the Queensland economy picks up and interstate migration to Queensland reaches higher levels.

There are over 44,000 domestic customers connected to the Brisbane Network with annual usage of 12 GJ/pa per site but their market share is less than 8 per cent. Increased market penetration of hot water heating is expected to raise household consumption to some degree but demand growth is projected to be less than 2 per cent per annum. The increase in Queensland's population towards the end of the period should boost residential load growth.

8.2.2 The Toowoomba region

The Darling Downs area has a population of approximately 200,000 and in 1997/98 recorded population growth of only 0.3 per cent. It is an area of low population growth and moderate economic growth and the Toowoomba gas distribution Network is well established.

The volume of gas distributed in the region is 15 per cent the size of the gas load in Brisbane. Large industrials are still the primary customers with 60 per cent of consumption but residential customers have a greater share than in the Brisbane region, in part due to the higher household usage of 20 GJ per annum.

8.2.3 South Coast

The South Coast is an area of 1400 km^2 and has approximately 600,000 inhabitants. Its population growth of over 3% in 1997/98 was well above the state growth rate of 1.7%.

The Allgas distribution system at the Gold Coast was only established in 1991. As a relatively new extension to the Network, most initial connections were for industrial and commercial purposes with these sectors currently accounting for 95 per cent of gas deliveries.

The larger industrial customers have already connected to the distribution system so future connections are expected to be primarily for residential and commercial purposes. High percentage growth is projected for residential and commercial demand – albeit, from small starting loads.

8.2.4 Total Allgas Region

In total, growth of gas deliveries by Allgas is projected to slow in the next two years as business investment, construction and the Queensland economy slows.

New gas sources are expected to come on-stream and the extra gas availability combined with an improving economy is expected to bolster Queensland gas demand sharply. It will have a positive but small impact on Allgas loads. Growth in Allgas gas deliveries is expected to average around 3 per cent for the rest of the decade.

Table 8.5: Demand Forecasts (TJ)

Year ending 30 June	00/01	01/02	02/03	03/04	04/05	05/06
Small Customer Sales	2255	2324	2431	2546	2665	2793
Large Customer Sales	7255	7147	7562	8074	8611	9010
Total Sales	9510	9471	9992	10621	11276	11803

Allgas will report to the regulator by no later than 30 September of each year on performance against forecasts for the previous financial year of gas demand on an aggregate (whole of covered Network) basis and for each customer class.

9 COST ALLOCATION METHODOLOGY

9.1 Code Requirements

8.1 The service provider's reference tariff and reference tariff policy should be designed with a view to achieving the following objectives:

(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 any of these objectives conflict in their application with a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can be reconciled or whether a particular objective should prevail.

8.2 Factors about which the regulator must be satisfied in determining to approve a reference tariff and reference tariff policy are that:

(a) the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement Period (the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in Section 8;

(b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in this Section 8;

(c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service (referred to in paragraph b) is recovered from the Users of that Reference Service consistently with the principles contained in this Section 8;

(d) incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this Section 9; and

(e) any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.

Section 8.1 of the Code specifies the requirements of the Service Providers Reference Tariff and Reference Tariff Policy. This Section 9 seeks to convey the principles underpinning the Allgas cost allocation methodology and the inherent satisfaction of the Code requirements resulting from that process.

9.2 Reference Tariff Cost Allocation Principles

The Reference Tariffs are designed to meet the Code's objectives as explained below. The key objectives of the policy include recovering the efficient costs of providing Reference Services, with emphasis on the safety and integrity of the Network, providing price certainty to Network Users, and signalling appropriate investment in the development of the market.

The tariffs have been determined using a cost of service approach where the total revenue is calculated on the basis of a rate of return on the capital base plus depreciation of the capital base plus the efficient operating, maintenance and other non-capital costs of the Network.

- Cost Reflectivity – The tariffs reflect a recovery of efficient costs associated with delivering the services of the Network. When benchmarking these costs against other providers, Allgas' costs are relatively low. Built into the forecasts are incentive mechanisms for efficiency gains and these will pass directly to Users within this regulatory review period.

  Forecast operating and maintenance costs deliver efficiency gains each year over the five year term of the Access Arrangement. These efficiency gains are to be achieved from a current cost base that is already relatively low when compared to similar Networks.

- Efficient Pricing Signals – The revenues associated with the Reference Tariffs reflect economically efficient pricing principles. That is, the revenues for each of the Reference Tariffs have been set so that they are between incremental and stand-alone prices. If revenue falls below the incremental cost of supply for an End User the incentive for Allgas to connect similar Prospective End users is removed. If revenue per End User exceeds the stand-alone costs of replicating the Reference Service there is a risk of bypass resulting in inefficient use of resources. Thus the Reference Tariffs have been structured so that resources are allocated efficiently.

  Within each of these Reference Tariffs some re-balancing will be required over a transitional period to ensure that the pricing for individual End Users also complies with efficiency criteria.

- Price Stability – The reference tariffs have been designed to provide certainty and stability of pricing for all Users. Reference Tariffs have been smoothed over the term of the access arrangement to avoid shocks in any year and provide stability and certainty for End Users.

- Competitive market – The tariffs are designed so that the prices reflect the most efficient use of the distribution system resources. Assets are allocated to each Tariff class according to the relative use by that customer class. Operating and other non-capital costs are allocated to the appropriate assets and then to the Tariff classes. Costs are benchmarked and prices are forecast to deliver real gains in productivity to Network Users.

- Safe and reliable operation – Capital expenditure and operating and maintenance cost forecasts are designed to deliver distribution Network safety and integrity both in terms of design and operation. Network Users are entitled to the safe use of the distribution system and forecasts are designed to deliver benefits both in terms of reduced unaccounted for gas and reduced operational and maintenance expenditure.

- Environmental Sustainability – The Reference Tariffs have been designed to provide for increased gas consumption by End Users. Natural Gas is an environmentally friendly energy source and its increased usage is beneficial to the environment and encouraged by Government as evidenced in the recently published Queensland Energy Policy – A Cleaner Energy Strategy. Increased gas usage will in turn increase the utilisation of existing assets and drive lower unit costs for the usage of such assets.

- Appropriate Investment Decisions – The Reference Tariffs are modelled so as to provide efficient investment signals for the development and growth of the Network. The Reference Tariff for the Large Customer Service has been designed to avoid uneconomic duplication of the Network and encourage an efficient use of resources. The fixed and variable components of pricing have been designed to signal the most efficient use of assets and maximise utilisation of the Network. This also results in a tariff which represents an efficient Network design to supply that End User.

The pricing approach for the Large Customer Group incorporates the prudent discount approach identified in Section 8.43 of the Code. The regulator has approved the application of prudent discounts for particular Large Customers.

9.3 Overview of Cost Allocation Process

Allgas assigned the Target Revenue to the Customer Service groups using a cost allocation process. This process involves the following main steps:

- determine target revenue for year – refer Section 2 above for derivation;

- capital, operating and maintenance costs relating to the Network assets are divided into cost pools based on defined asset groups;

- customer Service groups (and thus the tariff categories) are defined based on consumption levels, allocated connection infrastructure and location;

- the costs for the End Users from the Large Customer Service group are deducted based on stand-alone pricing principles; and

- the remaining costs are allocated based on asset usage.

Reference Tariffs are designed to recover the target revenue allocated to that Customer Service group based on the forecast utilisation and customer growth.

This target revenue apportionment and cost allocation approach ensures that the revenue derived from the application of the Reference Tariffs (modelled using the forecast demand and customer growth) delivers the target revenue.

9.4 Customer Groups

The Haulage Reference Services derived for application under the Access Arrangement are as follows:

- Small Customer Service; and

- Large Customer Service.

These Reference Services or Customer Service groupings were chosen to represent reasonably homogeneous groupings of End Users taking into account the consumption patterns and quantities, the connection and Metering types and End User locality while also considering pricing constraints.

Table 9.1 below sets out the Customer Service grouping adopted and the definition of the Reference Service, as defined in the Access Arrangement.

Note that the information in Table 9.1 shows the Customer Service grouping (customer numbers as at 30 June 2000) for calculation of the cost of supply only.

Table 9.1: Customer Groups

Customer Group	Description/Reference Service	Number of Customers
Small	The Small Customer Service is available where the End User is reasonably expected to withdraw a quantity of Natural Gas less than 10TJ per year. This Service provides for the transportation of gas delivered into the Network by or on behalf of the End User. Deliveries of gas may only be curtailed or interrupted in specified circumstances (eg. emergencies, events of force majeure, Network maintenance as described in Section 12 of the Terms and Conditions document).	58 870
Large	The Large Customer Service is available where the End User is reasonably expected to withdraw a quantity of Natural Gas of at least 10TJ per year. This Service provides for the transportation of gas delivered into the Network by or on behalf of the End User. Deliveries of gas may only be curtailed or interrupted in specified circumstances (eg. emergencies, events of force majeure, Network maintenance as described in Section 12 of the Terms and Conditions document).	109

9.5 Locational Zones

In the initial evaluation of cost allocation and pricing for the Large Customer Service, Allgas investigated the option of average pricing as used by most other gas utilities in Australia. However, Allgas has a unique situation in that the transmission pipeline is relatively close to many of its largest End Users and hence physical bypass is a real consideration. Calculations show that average prices for the Large Customer Service will result in some End Users receiving prices above stand-alone cost of supply, whereas others will receive prices well below the stand-alone costs. These inefficient pricing outcomes are not desirable for either Allgas or the Network Users. Allgas is at risk of physical bypass and the Users are paying for unacceptably high costs in consideration of the actual costs for their supply. Allgas therefore investigated and implemented the option of establishing pricing zones for those End Users taking a Large Customer Service. The zones established are:

- Brisbane – 3 Zones based on distance from the transmission pipeline;
- Toowoomba – 2 Zones based on distance from the transmission pipeline;
- Oakey – 2 Zones, and
- South Coast – 3 Zones based on distance from the transmission pipeline.

The primary considerations adopted by Allgas in the establishment of these zones include:

- cost reflectivity – maximising the linkage between Network prices and the cost of supplying individual End Users that qualify for the Large Customer Service;
- simplicity – providing a price that can be readily understood by all Users;
- deterring uneconomic bypass in response to incorrect pricing signals that can occur through extensive averaging of prices; and
- minimisation of boundary conditions.

The locational pricing zone Reference Tariffs for the Large Customer Service were delivered by utilising a number of stand-alone Networks. These stand alone Networks were used to calculate the portion of the allocated costs attributable to the Large Customer Service group in a particular supply area. This process involved:

- identifying the location of each End User within the Large Customer Service group with respect to the transmission pipeline;
- identifying the costs of an efficient stand-alone Network to supply the End User from the transmission pipeline. In some instances this involved the grouping of several End Users to provide efficient infra-structure to that group of End Users; and
- computing the required revenue for each End User resulting from this efficient stand-alone Network.

9.6 Revenue Allocation

The revenue allocation for the Allgas Network was carried out as follows:

Step 1

To deliver an efficient pricing level for every End User in the Large Customer Service group, a model was used to calculate a Network cost reflective of the optimum assets required to provide the service, and including utilisation of shared infrastructure where there are multiple End Users in a cluster. The revenue requirement for the Large Customer Service is derived in this way.

Step 2

The costs derived under step 1 are then used to derive the allocation of asset related costs to the Large Customer Service.

Step 3

The final step in the process is to allocate remaining asset related costs to the Small Customer Service.

9.7 Allocation of Unaccounted For Gas

As discussed in Section 3.4, Unaccounted for Gas (UAG) occurs due to a combination of leakage in pipes, Metering errors and accounting errors created by timing differences in Meter readings.

Allgas has allocated UAG based on an allowance of 0.1% of throughput for the Large Customer class and 12% of throughput for the Small Customer class. This equates to an overall allowance of 3 per cent of total throughput. This allocation is consistent with experience which indicates that the vast majority of leakage within the Allgas network comes from the low pressure mains.

9.8 Total Revenue Outcome

The Reference Tariffs arising from the cost allocation and tariff structure process were modelled against the forecast consumption and demand parameters and the total forecast annual revenue derived. The total revenue outcome is reflective of the total revenue for 2000/01 as allocated through the methodology described in previous Sections. This modelling ensures compliance of the Allgas Reference Tariff with Section 8 of the Code, in that the Reference Tariffs recover from users of that Reference Service an appropriate portion of Total Revenue.

10 REFERENCE TARIFF DESIGN

10.1 Introduction

This Section sets out the process by which the allocated costs are converted to reference tariffs.

The reference tariff design incorporates the following key features:

- nominated MHQ charges for the Small and Large End Customer Service;
- monthly fixed charges based on the nominal Metering and service facilities; and
- monthly volume ($/GJ) charges based on the actual gas consumption or average MDQ.

The remainder of this Section focuses on the description of the process as it is applied to each of the Reference Tariffs.

10.2 General Principles

The principles adopted in the development of the Reference Tariff structures for the two Customer Service groups include:

- fixed charges cover a proportion of the Service and Metering costs as well as a percentage of the administration costs;
- nominated MHQ or demand charges reflect the average costs of shared Network provision or contracted capacity;
- $/GJ or MDQ charges are used for the recovery of other costs; and
- the volume or MDQ charges are stepped to provide incentives to improve Network utilisation.

The tariffs ensure that there are no major pricing discontinuities at the boundary between Reference Tariffs. Such discontinuities can provide perverse incentives for End Users to change tariff categories.

10.3 Transitional Principles

The Reference Tariffs take account of the following factors:

- the need to avoid price shocks when the prices are initially introduced;
- the need to transition towards full cost reflectivity; and
- the recovery of reasonable revenues to enable Allgas to continue the operation of the Network in a viable manner.

In recognition of these factors, the Reference Tariffs have been set initially to recover target revenues while not causing significant price changes to End Users. Over the period of the Access Arrangement, the Reference Tariffs will be adjusted in accordance with the mechanisms described in Section 3.3 of the Access Arrangement document. This will enable a progression towards full cost reflectivity.

This results in the following revenue targets for each customer class, consistent with the price paths outlined in the Access Arrangement.

Table 10.1: Revenue by Customer Class ($m Nominal)

Year ending 30 June	00/01	01/02	02/03	03/04	04/05	05/06
Large customer class	10.0	10.1	10.3	10.4	10.6	10.8
Small customer class	17.8	19.1	20.5	21.9	23.6	25.3
Target Revenue	27.7	29.2	30.7	32.4	34.2	36.1

This results in the following revenue targets for each customer class, consistent with the price paths outlined in the Access Arrangement.

Table 10.2: Customer Class Revenue by region ($m Nominal)

	Small Customer Class		Large Customer Class	
Year ending 30 June	**00/01**	**01/02**	**00/01**	**01/02**
Brisbane	10.9	11.6	6.7	6.7
Toowoomba and Oakey	3.9	4.2	1.1	1.1
South Coast	3.0	3.4	2.2	2.3
Target Revenue	17.8	19.1	10.0	10.1

The revenue targets for each class are not shown by region after 2001/02 because accurate regional demand forecasts do not exist for this period.

For the Small Customer Class, revenue by region will grow in direct proportion to demand growth because there is only one reference tariff for all small customers in the Allgas network.

The revenue by region for the Large Customer Class will not change in direct proportion to demand growth because of the different zonal tariffs. The annual variation in revenue by region will be clarified with the QCA when network prices are submitted each year.

11 DESCRIPTION OF THE NETWORK

The following is a brief description of the Allgas distribution system. The system is separated into four (4) Natural Gas operating regions. These are the “Brisbane Region” (south of the Brisbane River); “Western Region” (encompassing the townships of Toowoomba and Oakey in Queensland); “South Coast Region” including Surfers Paradise and Coolangatta and “Tweed Heads” in north east New South Wales.

Maps of the Network are included as appendices to this Access Arrangement Information document.

The following table 11.1 provides information about the system load profile as required by the Code.

Table 11.1: Gate Station Volumes

Gate Station Volumes as a ratio of monthly volume against lowest month in last 12 months

		Oakey Ratio	Toowoomba Ratio	Ellengrove Ratio	Runcorn 1 Ratio	Runcorn 2 Ratio	Mt Gravatt Ratio	Tingalpa Ratio	Doboy Ratio	Dinmore Ratio
June	1999	1.59	1.71	1.24	1.20	1.29	1.02	1.15	1.25	1.13
July		2.31	1.66	1.31	1.26	1.30	1.10	1.20	1.32	1.04
August		1.78	1.72	1.32	1.26	1.29	1.13	1.14	1.30	1.05
September		1.43	1.43	1.28	1.20	1.31	1.08	1.13	1.31	1.10
October		1.28	1.33	1.23	1.23	1.19	1.06	1.13	1.20	1.11
November		1.37	1.24	1.22	1.30	1.25	1.06	1.07	1.23	1.00
December		1.00	1.07	1.02	1.05	1.06	1.00	1.04	1.05	1.12
January	2000	1.18	1.00	1.02	1.00	1.00	1.01	1.00	1.01	1.10
February		1.30	1.13	1.12	1.16	1.05	1.00	1.00	1.14	1.11
March		1.38	1.20	1.15	1.14	1.13	1.06	1.06	1.18	1.19
April		1.07	1.17	1.00	1.04	1.06	1.01	1.04	1.00	1.10
May		1.49	1.54	1.21	1.26	1.29	1.10	1.15	1.22	1.18

11.1 Allgas Distribution Network – Brisbane Region

The 2000 square kilometre Allgas gas distribution Network is located on the southside of the Brisbane River starting from Dinmore and Springfield in the west to Cleveland in the east, Marsden and Loganlea in the south and Wynnum in the north. The Network comprises approximately 1300 km of high pressure, medium pressure and low pressure pipelines. The Network is constructed of steel, polyethylene and cast iron mains.

Natural gas is supplied into the distribution Network from the APT transmission supply pipeline. The APT 300DN steel, Class 600, metropolitan line from Goodna to Gibson Island operates at a nominal operating pressure of 4200 kPa across the city. Seven (7) gate regulator stations are situated at Dinmore, Ellengrove, Runcorn, Wishart, Tingalpa and Doboy.

The natural gas from the APT pipeline is Metered at the gate stations by turbine Meters with flow computers used to correct for pressure and temperature variations. Odorisation of the gas is also provided at the gate stations.

The older areas of the Network comprising cast iron and steel mains are supplied through subgate or district regulator stations at Ekibin, West End, Wishart, Morningside, Salisbury, Sherwood and

Wynnum. The district regulator stations serve as a pressure letdown facility from the high pressure into the medium pressure and low pressure systems. The volume of gas entering the medium and low pressure areas is Metered and used in unaccounted for gas (UAG) calculations. These district regulator stations are also used for humidifying and oil fogging of the gas flowing through areas where older pipelines are installed. The purpose of this process is to preserve the integrity of the old cast iron and steel Networks.

The Brisbane distribution Network is divided into high pressure (steel and PE), medium pressure and low pressure systems.

11.1.1 High Pressure Steel System

The 200 km high pressure Network is comprised of Class 150 and Class 300 steel pipelines as shown in Table 11.2. The operating pressures of the high pressure system are set at the gate stations. Table 11.2 details the operating pressures of the various high pressure systems. The high pressure steel system is connected to high pressure polyethylene (PE), medium pressure and low pressure systems by approximately 200 district regulating stations.

Table 11.2: High Pressure System (Steel)

Gate Station	Location	Class	MAOP (kPa)	Nominal Operating Pressure (kPa)
Dinmore	Riverview Road, Ipswich	300	4200	650
Ellengrove	Woogaroo Street	150 300	1200 4200	1000 2200
Runcorn	Gowan Road	150 300	1200 4200	1000 2350
Mt Gravatt	Greenwood Street	150	1200	800
Tingalpa	Stanton Road	150	1200	850
Doboy	Lytton Road, Murarrie	150	1200	900

11.1.2 High Pressure Polyethylene System

A high pressure PE system operates in parallel with a high pressure steel system in various parts of Brisbane. The system consists of approximately 250 km of PE mains ranging from 40 mm to 160 mm in size. The 500 kPa MAOP (Maximum Allowable Operating Pressure) system generally operates between 100 to 200 kPa pressures. Geographically, this system operates through Woodridge, Kingston, Carole Park, Forest Lake, Springfield, Loganlea, Eagleby, Algester, Jindalee, Inala, Sunnybank, Mansfield, Manly, Tingalpa, West End, Woolloongabba and other parts of Brisbane.

11.1.3 Medium and Low Pressure Systems

The medium pressure distribution Network comprises a total of approximately 400 km of pipeline with sizes ranging from 50 mm to 450 mm. Approximately 200 km of the mains are cast iron or steel.

The low pressure Network comprises approximately 375 km of steel and cast iron mains in the older districts of Brisbane and Wynnum. Approximately 160 km of these mains are currently located under roadways due to road widening operations over the last several decades. In addition, the low pressure Network contains approximately 70 km of PE or PVC gas mains.

The sizes of PE, PVC, steel and cast iron main ranges from 40 mm to 350 mm.

There are three (3) major medium and low pressure systems in Brisbane.

11.1.4 Sherwood System

This system is fed by the Sherwood district regulator station. The system is a medium pressure Network. The MAOP of this medium pressure Network is 35 kPa and the average operating pressure is 15 kPa. The system is comprised of steel, cast iron and PE mains.

11.1.5 Older Districts

This system covers the inner city areas of West End, Woolloongabba, Balmoral, Camp Hill, Coorparoo, Holland Park, Moorooka and Yeronga at its boundaries. The system is a complex Network of low and medium pressure mains comprised of steel, cast iron and PE. The average operating pressure is 22 kPa for the medium pressure Network and 1.25 kPa for the low pressure Network.

11.1.6 Wynnum System

This low pressure system covers the suburbs of Wynnum, Manly and Lota. The majority of the mains are steel and cast iron. The system operates between 1.3 and 1.6 kPa pressures.

11.2 Allgas Distribution Network – Western Region

The 116 square kilometres of the Allgas Western Region Network consists of 96 square kilometres within the Toowoomba area, bordered by the escarpment in the east to Watson Court in the West, Hermitage Road in the North to Nelson Street in the South.

The remaining 20 square kilometres are located within the Jondaryan Shire Council boundaries at Oakey, with the Network extending from Kearneys Road in the West to; Hamlyn Road in the East, Oakey Aviation Base on Orrs Road to the North and Shannan Street to the South.

A 17.8 kilometre spur main from the Oakey Gate Station extends southward to Purrawanda to supply a single load industrial End User.

Both Toowoomba and Oakey Gate Stations are supplied with transmission pressure (5500 to 7000 kPa) gas from the Ballera to Roma and Roma to Brisbane pipelines. The Roma to Brisbane pipeline is owned by APT and operated by Agility. The gate station at Oakey is owned and operated by Allgas, whereas the Toowoomba Gate Station is operated by Agility. At Toowoomba Gate Station, the odorisation facilities and final stage stand-by regulator are owned by Allgas.

Natural gas is Metered at the gate stations by turbine Meters with flow computers used to correct for pressure and temperature variations.

The Oakey Network is a relatively new system with only three (3) sub-systems and operating pressures, i.e:

(a) high pressure, Class 150, steel operating at a nominal pressure of 1000 kPa (MAOP 1200 kPa);

(b) high pressure PE Network operating at a nominal pressure of 140 kPa (MAOP 500 kPa); and

(c) high Pressure PE Network operating at a nominal pressure of 680 kPa (MAOP) 700 kPa).

The township of Toowoomba is comprised of (a) and (b) above, plus the old converted town gas low pressure Network operating at a nominal pressure of 1.25 kPa. The low pressure mains construction dates from 1880 to the present, and consist of cast iron, UPVC, steel, galvanised malleable steel, copper and PE.

Within Toowoomba there are a number of sub-Networks with varying operating pressures as described in Table 11.3.

Table 11.3: Toowoomba System

High Pressure Steel	High Pressure PE	Low Pressure Wet Gas
Class 150 OP=1150kPa,MAOP=1200 kPa Class 300 OP=1150kPa, MAOP=4200 kPa	Class 500 OP = 200 kPa MAOP = 500 kPa	OP = 1.25 kPa MAOP = 2.0 kPa
Medium Pressure	**Medium Pressure Dry Gas**	**Low Pressure Dry Gas**
OP = 17 kPa MAOP = 35 kPa	OP = 7.0 kPa MAOP = 35 kPa	OP = 1.25 kPa MAOP = 2.0 kPa

11.2.1 High Pressure Steel System

The 46 kilometres of high pressure Network is comprised of Class 150 and Class 300 steel pipelines as shown on Table 11.4. The maximum operating pressures of the high pressure system are set at the gate stations. The high pressure steel systems supply gas to the high pressure PE, medium and low pressure systems via district regulating stations.

Table 11.4: High Pressure Steel System

Gate Station	Location	Class	MAOP (kPa)	OP (kPa)
Oakey	Cnr Kearneys Rd & Warrego Hwy	150	1200	1000
Toowoomba	Hermitage Road	150 300	1200 4200	1150 1150

11.2.2 High Pressure Polyethylene System

Approximately 230 kilometres of the Network is high pressure PE. Pipe sizing ranges from 20 mm to 160 mm with the Toowoomba low and medium pressure system gradually being renewed with high pressure PE. Oakey township operating pressure is currently 140 kPa with Toowoomba township operating at 170 kPa. The spur line from the Oakey Gate Station to Purrawanda is 100mm and 160mm Class 700 PE operating at 680 kPa.

11.2.3 Medium Pressure System

Three (3) medium pressure systems operate within the Toowoomba Network and supply PVC and steel mains ranging in size from 32 mm to 150 mm.

The supply points for these systems are:

(a) Herries Street District Regulator Station;

(b) Margaret/Curzon Street District Regulator Station (in pit); and

(c) Ruthven/Lawrence Street District Regulator Station (in pit).

11.2.4 Low Pressure System

The low pressure wet gas systems are supplied from two (2) interconnected district regulator stations:

(a) Neil Street District Regulator and Metering Station; and

(b) Herries Street District Regulator and Metering Station.

At both stations, the gas is “conditioned” by water and oil fogging to control pipe joint leakage.

Gas Metering is also carried out at these stations.

Low pressure dry gas systems are supplied via the high pressure PE Network at various district regulator stations located in pits. Generally they are areas formerly attached to the wet gas Network that do not have pipe materials requiring conditioned gas. These newer systems have been disconnected from the wet gas system and are supplied by the dry gas PE systems.

Low pressure wet gas mains are generally cast iron and vary in size from 32 mm to 400 mm.

Low pressure dry gas mains are generally steel or PVC and range in size from 32 mm to 150 mm.

11.3 Allgas Distribution Network – South Coast Region

The south coast distribution Network extends from the Albert River in the North to Benora Point (Tweed Heads) in New South Wales in the South. The Network consists of a supply pipeline from the Albert River to Reedy Creek with distribution in the Yatala industrial areas and in the main residential/commercial areas from Runaway Bay to Coolangatta and Tweed Heads. The Network consists of approximately 111 kilometres of high pressure steel mains and 138 kilometres of high pressure PE mains.

The natural gas supply for the South Coast Region is from the Gowan Road Gate Station at Runcorn (Brisbane). A Metering and pressure reduction facility is installed at Ashmore Rd, Ernest.

11.3.1 High Pressure Steel System

The 111 kilometres high pressure Network consists of Class 150, 300 and 600 steel pipelines as listed on Table 11.5. The maximum operating pressure is set at the Gowan Road Gate Station. Class 600 and Class 300 mains operate at the same pressure, while Class 150 mains are regulated by district regulators at the connection points to the Class 300 and Class 600 mains. Operating pressures of the various systems are listed below:

Table 11.5: High Pressure Steel System

Class	MAOP (kPa)	Operating Pressure (kPa)	Comments
600	7800	2350	Operating pressures may be increased as demand requires
300	4200	2350	
150	1200	750	

The Class 600 and 300 system is basically a supply main running from the Gowan Road Gate Station south and parallel to the Pacific Highway through to the Ashmore Rd (sub-gate) Station and terminating at Reedy Creek.

11.3.2 High Pressure Polyethylene System

The high pressure PE system is basically a distribution Network located mainly in the tourist strip from Runaway Bay in the north to Benora Point in the south. The Network comprises a total of 138 km of polyethylene in sizes of 40, 63, 90 and 110 mm diameter. This system operates at pressures between 200 to 250 kPa with an MAOP of 500 kPa.

11.4 Gate Stations, District Regulators and SCADA

11.4.1 Gate Stations and District Regulators

Gate stations and district regulators are located throughout the system. The regulator stations generally consist of two regulators in series which employ an active monitor regulator configuration to ensure that security of supply and safe operating pressures are maintained in the system at all times. In the low pressure areas, a series of single regulators feed the low pressure area. In this instance, the supply pressure to the district regulator is usually not greater than 35 kPa. Failure of a low pressure regulator (these regulators normally fail closed) will generally not cause a problem because it is only one of several regulators feeding the same area.

Gate stations are located above ground. District regulator stations are generally located in underground pits.

Gate stations are generally located on company-owned land or on dedicated pipeline easements whereas district regulators are generally located within road reserves, ie. on nature strips.

Both the gate stations and district regulators are 100% pneumatically-controlled, ie. all systems are operated exclusively on pressurised natural gas from the supply pipeline. Filtration systems are provided to protect the regulators as well as the associated pneumatic control systems from any foreign matter that may potentially enter the system. Isolation valving is provided for routine maintenance activities and for emergency purposes.

11.4.2 SCADA Remote Monitoring

The gate stations which supply the Network are fitted with an automatic “dial-up by exception” system which monitors critical station operating parameters such as inlet and outlet pressures, gas temperature, station flow, unauthorised entry, etc. Excursions beyond preset limits initiate the automatic dial-up system to signal an alarm condition. Allgas staff monitoring the system are then able to dispatch field personnel to the site to assess and rectify any potential abnormal operating condition. In addition, Allgas provides roving pipeline patrols which perform regular spot checks and inspections regarding activities along the pipeline easement and critical Network facilities.

11.5 Gas Quality Characteristics

As a Network operator, Allgas is very conscious about the quality of natural gas taken from the transmission pipeline. An average sample of natural gas taken by Allgas contains 86% methane, 7.79% ethane, 2.63% nitrogen, 1.77% propane and 1.08% heavy hydrocarbons. The average heating value of the gas is approximately 40.2 MJ/Sm^3 (Megajoules per standard cubic metre). The gas density is 0.787kg/ Sm^3.

The natural gas taken from the transmission pipeline is sampled once every six minutes by a gas chromatograph for composition. The samples are then averaged for the day and subsequently for the month.

11.5.1 Natural Gas Specification

Allgas has set the following specification for natural gas entering the Network. This specification is similar to that used by Agility.

Heating Value

The heating value of the gas provided at the delivery point in any one day shall not be less than 37.45 MJ/Sm^3.

The gas shall contain not more than 3% by volume of carbon dioxide.

Water Dew Point

The water dew point of the gas shall be no greater than 0^oC @ 6895 kPa.

Oxygen

The gas shall contain not more than 0.1% by volume of oxygen.

Mercaptans

The gas shall contain not more than 4.6 milligrams per standard cubic metre of mercaptan.

Hydrogen Sulphide

The gas shall contain not more than 5.7 milligrams per standard cubic metre of hydrogen sulphide.

Total Sulphur

The gas shall contain not more than 23 milligrams per standard cubic metre of total sulphur.

Hydrocarbon Dew Point

The hydrocarbon dew point of the gas shall not be greater that 10^oC @ 3500 kPa.

Other Liquids and Solids

The gas shall be commercially free from dust, gums, gum forming constituents or other liquids or solid matter which might cause injury to or interfere with the proper operation of the gas transmission and distribution system.

Wobbe Index

The Wobbe Index of the gas shall not be less than 47.4 nor more than 51.1.

11.5.2 Odorisation

The purchased natural gas is odorised at the gate stations at Oakey, Toowoomba, Doboy, Tingalpa, Mt Gravatt, Runcorn, Ellengrove and Dinmore. Allgas uses Tetrahydrothiophene (THT) as an odorant, which is a flammable clear liquid with a specific gravity of 1.

Gas odorisation is carried out in a precisely controlled manner such that a small proportion of the total gas stream leaving the station is shunted through the odorising equipment where it becomes heavily odorised before being remixed with the main stream at the rate of 0.005 to 0.012 g/Sm^3.