GasNet Australia Access Arrangement Information

The Australian Competition and Consumer Commission revised this Access Arrangement Information (which was submitted by GasNet on 6 January 2003) so that it was consistent with the revised Access Arrangement drafted and approved by the Commission for GasNet (published on 17 January 2003). This Access Arrangement Information has been further revised so that it is consistent with the Access Arrangement as varied to reflect the order of the Australian Competition Tribunal.

This Access Arrangement Information should be read in conjunction with the Supplementary Access Arrangement Information submitted by GasNet on 6 December 2002.

Date of Order 23 December 2003

Commencement Date: 1 January 2004

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Details

Covered Pipeline	GasNet System ("**GNS**")	
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Commencement Date	1 February 2003	
End Date	31 December 2007	

GasNet Australia Access Arrangement Information

1 Introduction

1.1 Purpose

Editorial Comment

On 27 March 2002, GasNet lodged with the Commission its proposed Access Arrangement and Access Arrangement Information for the Second Access Arrangement Period commencing on 1 January 2003. These were lodged under section 2.28 of the Code.

The Commission, in its Final Decision (13 November 2002), decided not to approve GasNet's proposed revisions.

In response, GasNet submitted, on 6 December 2002, amended revisions together with revised AA Information and Supplementary Access Arrangement Information. On 6 January 2003, GasNet submitted a revised version of its amended revisions and AA Information.

On 15 January 2003, the Commission decided, under section 2.41 of the Code, not to approve GasNet's amended revisions. As required by section 2.42 of the Code, the Commission drafted and approved its own revised Access Arrangement for GasNet. The revised Access Arrangement commences on 1 February 2003.

The Commission has revised the AA Information submitted by GasNet on 6 January 2003 so that it is consistent with the revised Access Arrangement drafted and approved by the Commission. As discussed in chapter 9 of the Final Approval (published by the Commission on 17 January 2003), the Commission has amended:

- Tables 3-1, 3-4, 3-4A, 3-6, 3-7, 3-8, 3-9, 3-10, 3-11 and 3-12; and
- certain prudent discounts in clause 5.11.

The Commission has made certain editorial changes but has not deleted any of GasNet's arguments contained within this AA Information. Where relevant, the Commission's disagreement with these arguments is noted in its Final Decision of 13 November 2002.

This AA Information should be read in conjunction with the Supplementary Access Arrangement Information submitted by GasNet on 6 December 2002.

Purpose

The purpose of this AA Information is to assist Users and Prospective Users to understand the derivation of the elements of GasNet's proposed Access Arrangement. (Editorial comment: On 15 January 2003, the Commission drafted and approved its own revised Access Arrangement for GasNet).

Consistent with the allocation of responsibilities (under section 10.2 of the Code) between GasNet and VENCorp, this AA Information addresses the categories of information in Attachment A of the Code, except information in relation to the total number of customers in each pricing zone, service or category of asset. GasNet understands that VENCorp has incorporated this data into its Access Arrangement Information.

1.2 Description of GNS

The GNS is a high pressure gas transmission network which transports natural gas within Victoria and to New South Wales via the Interconnect Pipeline. As at 1 January 2003, the GNS:

(a) comprises approximately 1,930 km of pipelines;

(b) has four main injection points at:

(i) Longford (adjacent to the Esso/BHP Billiton processing facility and the EGP hub);

(ii) Culcairn (the interconnection with the Moomba-Sydney Pipeline System);

(iii) Port Campbell (the injection point for WUGS and local fields); and

(iv) Dandenong (the site of the LNG facility); and

(c) serves a total consumption base of approximately 1.4 million residential consumers and approximately 43,000 industrial and commercial consumers in Melbourne and regional Victoria.

At the time the original Access Arrangements were submitted for approval to the Commission in 1997, GasNet's transmission assets consisted of two separate networks, the Former PTS and the WTS. However, as a result of construction of the SWP, the WTS is now physically connected to the Former PTS. For the purposes of GasNet's draft Access Arrangement, the whole network is now referred to as the GNS.

A description of the GNS including pipe sizes and distances, maximum operating pressures and a map of the system are contained in Schedule 1.

1.3 Maximum Delivery Capability

The Service Envelope Agreement between GasNet and VENCorp sets out the amount of pipeline capacity that GasNet will provide to VENCorp under certain defined conditions. It is contemplated that the Service Envelope Agreement will be amended prior to the commencement of the Second Access Arrangement Period to include the capacity associated with the WTS.

2 Capital Base

2.1 Initial Capital Base

In order to establish the Capital Base at the start of the First Access Arrangement Period, GasNet (then TPA) commissioned GHD to provide a valuation of the transmission assets. GHD established a value for the assets based on the ODRC methodology for the period ending 30 June 1997.

GHD adopted the ODRC methodology in valuing GasNet's assets. The ODRC approach measures the cost of replacing the existing network with a new optimised network designed for maximum cost effectiveness, using modern materials and construction techniques. The optimised network was depreciated to reflect the unexpired economic life of the existing network. In completing the valuation, GHD reviewed and modified the economic life to take into account such factors as technological change, trends and geographical shifts in demand and current estimates of proven and probable reserves in Australia.

The Commission found that $363.7 million at 30 June 1997 was the reasonable value on which to base the initial Capital Base in the Final Decision. The Commission then adjusted this figure by taking into account two amendments. Firstly, the Commission used actual inflation, rather then forecast inflation, and appropriate depreciation to convert the 1 July 1997 figures provided in the GHD report to 1 January 1998. Secondly, the Commission allocated a proportion of indirect assets to excluded services. The adjusted figure was $358.0 million which formed the Capital Base at the commencement of the First Access Arrangement Period.

2.2 Rolled Forward Capital Base

Consistent with section 8.9 of the Code, GasNet has adjusted the Capital Base to account for:

(a) depreciation in the First Access Arrangement Period ;

(b) New Facilities Investment during the First Access Arrangement Period, which, subject to satisfying the tests in section 8.15 and 8.16 of the Code, is included in the Capital Base at cost;

(c) inflation in the First Access Arrangement Period.

Table 2-1 sets out how the Capital Base was adjusted over the First Access Arrangement Period.

Table 2-1: Roll-forward of the capital base

Year ending 31 December	$ million				
	1998	1999	2000	2001	2002
Opening capital base	358.0	389.7	476.8	493.3	496.4
Inflation	5.7	7.0	27.7	15.4	14.1
Depreciation allowance[a]	-12.5	-13.9	-15.7	-16.7	-17.0
Capital expenditure[a]	38.6	94.1	6.3	4.6	0.6
Disposals/Redundancies	0	0	-1.8	-0.2	0.0
Closing capital base	389.7	476.8	493.3	496.4	494.1

2.3 Accumulated Depreciation

Accumulated depreciation of the Capital Base to 31 December 2002 is shown in Table 2-2 below.

Table 2-2: Accumulated Depreciation ($ million)

Accumulated depreciation identified in GHD valuation as at 30 June 1997	225.0
Plus depreciation for period 30 June 1997 to 31 December 2002	81.7
Accumulated Depreciation as at 31 December 2002	306.7

2.4 Summary of Capital Base

Table 2-3 describes the Capital Base (by category of asset) at the commencement of the Second Access Arrangement Period. These figures are in nominal dollars assuming actual CPI from 1 January 1998 to 30 September 2002 and 2.16% CPI forecast from 30 September 2002 to 31 December 2002.

Table 2-3: Capital Base as at 1 January 2003 (Nominal $ million)

Facility Category	ODRC Value
Pipelines	417.8
Compressors	47.0
Odourisation	0.1
System Control	20.3
Gas Quality	0.1
General Land & Buildings	8.2
Other	0.6
Total	494.1

3 Revenue Requirement

3.1 Total Revenue

GasNet has used the Cost of Service methodology for determining its Total Revenue requirement. Using this methodology, Total Revenue is calculated on the basis of:

(a) a return (Rate of Return) on the Capital Base;

(b) depreciation of the Capital Base; and

(c) the operating, maintenance and other non-capital costs incurred in providing all Services provided by the GNS.

In addition, section 8.20 of the Code provides that Reference Tariffs may be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement Period, provided that such investment is reasonably expected to pass the requirements of section 8.16 of the Code when the investment is forecast to occur.

3.2 Rate of return

The values of the various parameters of the cost of capital are provided in Table 3-1.

Table 3-1: WACC Parameters

WACC Parameter	
Real risk free interest rate	3.33%
Nominal risk free interest rate	5.57%
Expected Inflation	2.16%
Debt Margin	1.71%
Cost of Debt	7.28%
Market Risk Premium	6.0%
Gearing Ratio	60.0%
Corporate Tax Rate	30.0%
Value of Imputation Credits	50.0%
Asset Beta	0.500
Debt Beta	0.184
Equity Beta	0.973
Return to Equity	11.40%
Nominal Vanilla WACC	8.93%
Real Vanilla WACC	6.62%

3.3 Depreciation Allowance

The Depreciation Schedule for the First Access Arrangement Period was based on a real straight line depreciation profile. GasNet has retained this methodology, except for the SWP, where some depreciation will be deferred beyond the Second Access Arrangement Period in comparison with the real straight line profile.

Asset Categories and Technical Life

Table 3-2 shows the defined asset groups and technical lives adopted for each group.

Table 3-2: Assets categories and technical life

Asset Category	Technical Life
Compressor Stations	30 years
Heaters	20 years
Pipelines (including line and branch valves)	60 years
Telemetry equipment	5 years
Buildings	60 years
Land	NA
Office Equipment	5 years

The asset groups and the technical lives remain unchanged from the First Access Arrangement Period except for a further sub-categorisation of pipeline assets.

Economic Life

The estimated remaining economic lives of GasNet's pipeline assets as concluded by the Commission are set out in Table 3-3 below.

Table 3-3: Remaining Economic Life by Pipeline Group

Pipeline	End of life First AA Period (GHD 6/97)	End of life Second AA Period (31/12/2002)
Longford	2030	2023
Lurgi	2016	2016
SWP	NA	2052
WTS	2033	2033
Rest of System	2033	2033

Depreciation Schedule

Table 3-4 shows the calculated depreciation allowance for each class of asset and the total depreciation allowance that has been included in the Total Revenue. These figures are based on the existing CCA framework, with the exception of the SWP where some depreciation has been deferred beyond the Second Access Arrangement Period in comparison with the real straight line profile.

Table 3-4: Annual depreciation allowances, 2003 to 2007

	$ million[a]				
	2003	2004	2005	2006	2007
Pipelines	15.46	16.07	16.73	17.42	18.05
Compressors	3.90	4.11	4.34	4.39	3.92
System control facilities	0.79	0.76	0.95	1.09	1.25
Odourisation	0.01	0.01	0.01	0.01	0.01
Gas quality	0.02	0.11	0.11	0.12	0.12
General land and building	0.17	0.17	0.17	0.18	0.18
Other	0.23	0.23	0.21	0.17	0.14
Total of assets	20.57	21.46	22.52	23.38	23.66

3.4 Inflation

As GasNet has adopted a real rate of return tariff methodology, the Reference Tariffs incorporate an escalation of the Capital Base each year. GasNet has used an annual inflation rate of 2.16%.

3.5 Non-Capital Costs

GasNet's Non-Capital Costs consist of the following categories:

(a) operating costs, comprising:

(i) operating and maintenance costs (O&M), which by an activity allocation procedure is broken down into:

(A) pipeline maintenance costs; and

(B) compressor maintenance costs;

(ii) general and administrative costs (G&A);

(iii) fuel gas costs (for compressor operations and heaters);

(b) return on inventories and linepack;

(c) K-factor carry-over;

(d) asymmetric risk allowance;

(e) capital raising costs; and

(f) an allowance for regulatory review costs incurred in 2001 and 2002.

Each of these cost categories is summarised in Table 3-4A below and discussed in detail in the following paragraphs.

Table 3-4A: Non-capital costs for 2003 - 2007 ($ nominal million)

	2003	2004	2005	2006	2007
Operating costs	18.20	19.85	19.51	21.21	21.51
Asymmetric risks	0.18	0.19	0.19	0.20	0.20
Return on Inventories & Linepack	0.12	0.12	0.12	0.12	0.13
Capital Raising Costs	0.44	0.44	0.44	0.44	0.44
K-Factor Carryover	12.90				
Regulatory Review Costs	1.05				
TOTAL	32.90	20.60	20.26	21.97	22.28

Operating costs

All of GasNet's operating costs except for compressor fuel, odorant and electricity used at compressor station operations are fixed in nature. GasNet's forecast operating costs for the period 2003 - 2007 are shown in Table 3-5 below. These figures have been calculated using an inflation estimate of 2.16%.

Table 3-5: Forecast of GasNet's operating costs, Jan 2003- Dec 2007[1] (nominal $million)

Operating cost	**2003**	**2004**	**2005**	**2006**	**2007**
Pipeline maintenance	5.95	6.85	6.12	7.41	7.33
Compressor maintenance	3.30	3.55	3.68	3.72	3.80
G&A	7.76	8.16	8.29	8.52	8.69
Fuel gas	1.19	1.29	1.42	1.56	1.69
Total	18.20	19.85	19.51	21.21	21.51

The fuel gas forecast in Table 3-5 excludes the fuel gas associated with the operation of the Brooklyn compressor station to transport gas from Longford to refill WUGS. The level of use, and therefore refill, of the WUGS facility is uncertain and so any forecast of fuel use for this operation is subject to risk. GasNet has therefore developed a tariff that recovers only the incremental costs on the GNS of refill operations. Given the uncertainties associated with

[1] The forecast costs set out in Table 3-5 constitute that part of GasNet's operating costs which are relevant to the provision of the regulated service. GasNet also provides a metering service and an LNG service. The costs associated with these services have been separated from the costs associated with the regulated service according to a set of transparent accounting measures. Unregulated activity costs are confidential to GasNet. However, GasNet has provided the allocation model to the ACCC for its review.

the level of use of this service, this tariff is not included in the price control model. Therefore, the incremental costs are not included in the operating and maintenance cost forecast.

GasNet's historical operating costs are set out in Table 3-6A below.

Table 3-6A: Operating costs 1998 - 2002

1998	1999	2000	2001	2002
16.97	14.14	11.86	13.26	18.25[(a)]

[(a)] Estimated actual 2002

The forecast operating costs comprise a range of cost components, allocated as shown in Table 3-6 below.

Table 3-6: Components of Forecast Operating Costs 2003-2007 (nominal $ million)

Cost Category	2003	2004	2005	2006	2007
Labour	7.2	7.5	7.7	8.2	8.4
Materials	0.7	1.0	0.6	1.0	0.9
Fuel Gas	1.2	1.3	1.4	1.6	1.7
Outside Services - Gas Related	1.1	1.2	1.3	1.3	1.4
Outside Services - Other	3.0	4.0	3.4	4.4	3.7
Regulatory/Utility Charges	1.3	1.3	1.3	1.4	1.4
Occupancy	0.4	0.4	0.4	0.4	0.4
Communications	0.2	0.2	0.2	0.2	0.3
Motor Vehicle	0.5	0.5	0.5	0.5	0.6
Information Technology	0.4	0.4	0.4	0.4	0.4
Training	0.2	0.2	0.2	0.2	0.2
Travel	0.1	0.2	0.2	0.2	0.2
Promotions/Public Relations	0.02	0.03	0.03	0.03	0.03
Sundry	2.4	2.4	2.5	2.5	2.6
Labour Recoveries	-0.4	-0.8	-0.7	-1.2	-0.7
Total	**18.2**	**19.9**	**19.5**	**21.2**	**21.5**

There are a number of exceptional costs relating to regulated assets which must be taken into account when assessing GasNet's non-capital costs. These costs include regulatory reset costs, and, in the G&A area, extraordinary increases in insurance costs (the Service Envelope Agreement imposes an obligation on GasNet to insure the transmission system for their full insurable value against damage or destruction and to maintain public liability insurance of $250 million) and listing and governance costs (Board and ASX costs from 2002 onwards). These exceptional costs are set out in Table 3-7 below.

Table 3-7: Exceptional costs ($million)

Cost Category	2003	2004	2005	2006	2007
Reset Costs	1.05				
Increase in Insurance Costs	1.45	1.48	1.52	1.55	1.58
Listing & Governance Costs	1.06	1.09	1.12	1.15	1.19
Total	3.56	2.57	2.64	2.7	2.77

These costs have been calculated on the basis that 88.18% of the costs should be allocated to the regulated assets. The method of calculating this allocation is set out in the confidential model provided to the Commission.

Return on inventories and linepack

GasNet's Working capital allowance consists of the following costs:

(a) investment in passive linepack gas; and

(b) inventories (ie the cost of holding spares and materials to deal with emergencies and standard maintenance activities).

The appropriate return on working capital is the nominal WACC, which represents the actual "interest rate" to be paid each year on the investment in working capital.

Table 3-8 shows the cost associated with each of these items and the forecast return on working capital for the period 2003 to 2007.

Table 3-8: Forecast return on inventories and linepack

	2003	2004	2005	2006	2007
Return on linepack	0.09	0.09	0.09	0.09	0.10
Return on inventories	0.03	0.03	0.03	0.03	0.03
Total	0.12	0.12	0.12	0.12	0.13

K-Factor carry over

GasNet has maintained an account representing the K-factor and submitted this to the Commission each year as part of its annual tariff approval process. The K-factor which is to be rolled forward into 2003 under the Fixed Principles is calculated on the same basis as the annual K-factor. The KTb for 2002, calculated using the same model, will be added to the K-factor calculated for the year 2003 under the proposed new price control model for the Second Access Arrangement Period (see Schedule 3 of the draft Access Arrangement). The K-factor to be carried forward is $12.9 million in 2003 dollars.

GasNet has added the K-factor carry forward to the forecast operating costs as an extraordinary expense applying in 2003 only. However, this cost will be distributed over the recovery period 2003 to 2007 in the same manner that operating costs are levelised over 2003 to 2007 with the selected X factor.

Asymmetric risk allowance

GasNet has included in its cost of service an allowance reflecting the following asymmetric risk downsides that are not adequately reflected elsewhere in the Total Revenue calculation. Table 3-9 below details the allowance for each category of asymmetric risk.

Table 3-9: Categories of Asymmetric risk

Asymmetric Risk	Allowance ($ p.a.)
Extortion and bomb threats	10,000
Insurer credit risk	2,000
Employment Practices	35,000
Key Person	72,000
Uplift Liability	65,000
Total	**184,000**

Capital raising costs

GasNet's non-capital costs include an annual allowance for equity raising costs of 0.224 per cent of regulated equity which is to be recovered as an annual non-capital cash flow.

Regulatory Review Costs

In preparing its submission to the Commission for revision of its Access Arrangement, GasNet has needed to use resources in addition to its ongoing regulatory management. These resources have been required during 2001 and 2002. They consist of contract staff to assist in regulatory accounting and modelling and the commissioning of a number of studies by consultants on different aspects of the process.

Although these costs were incurred in 2001 and 2002, they relate to the 2003 to 2007 regulatory period. Furthermore, there was no allowance for these costs in the forecast non-capital costs for the current regulatory period. GasNet is including an allowance of $1,051,938 (2003 dollars) for these costs in its 2003 non-capital costs. Consistently GasNet has not included any allowance for the costs associated with the 2008 - 2012 regulatory period in its forecast non-capital costs for 2006 or 2007. GasNet expects that an allowance for these costs will be included in its 2008 non-capital cost forecast.

3.6 Forecast Capital Expenditure

The forecast capital expenditure for the Access Arrangement Period is set out in Table 3-10. An explanation of each of the items identified in Table 3-10 is provided below.

Table 3-10: Forecast Capital Expenditure (nominal $m)

Year ending 30 June	2003	2004	2005	2006	2007	Total
Gooding Compressor refurbishment	-	-	6.43	7.99	7.79	22.21
Lurgi pipeline refurbishment	2.04	2.09	1.54	-	-	5.67
City Gate Upgrades[2]	-	3.45	2.50	3.26	-	9.21
Wollert Automation	-	1.15	1.71	-	-	2.86
Gas Quality (Chromatographs)	0.92	-	-	-	-	0.92
Maintenance Capex	1.89	1.74	0.60	0.62	1.13	5.97
Total	4.85	8.43	12.77	11.87	8.91	46.84

Gooding Compressor Station Refurbishment

The Gooding compressor refurbishment is expected to be commissioned over the period 2005-2007 at a cost of $20.4 million (2002 dollars).

The compressor station, which was constructed in 1976, is nearing the end of its 30 year economic life and is showing signs of wear and erosion consistent with being in service for nearly 30 years.

Lurgi Pipeline Rehabilitation

The Lurgi pipeline was built in 1958 and is the oldest gas transmission pipeline in Australia. The Lurgi line was built in accordance with the available technologies and standards of the day. Pipe manufacturing, coating systems, construction techniques and corrosion mitigation science have since advanced significantly.

The Lurgi pipeline rehabilitation is expected to take place over the period 2004 - 2007. The capital works will be staged to ensure only necessary works will be conducted. The results of each stage will determine the nature of the expenditure for the next stage and hence final project costs will be dependent on the results of the initial pigging and subsequent dig up investigations. The cost estimate for Stage 1 (2002-2003 and 2004-2005) is $5.44 million (2002 dollars). The costs for Stage 2 (2005-2006 and 2006-2007) will be dependent on the results of stage 1 works.

Accordingly, only the cost estimate for Stage 1 will be included in the calculation of tariffs for the Second Access Arrangement Period at this time. In the event that GasNet is required to conduct Stage 2 works, it will seek to have the costs associated with those works rolled into the Capital Base under section 8.16 of the Code.

[2] This includes the gas heaters at Wollert, Dandenong and Tyers as discussed below.

City gate upgrades

Upgrades at the Dandenong, Wollert, Tyers and Morwell city gates will be conducted over the period 2004 to 2006. The forecast cost of the upgrades is $5.60 million (2002 dollars).

The majority of the regulators and associated controls which comprise the city gates are over 30 years old and experience frequent hydraulic oil leaks.

There are no liquid separation facilities (except at compressor station inlets) throughout the transmission system to separate liquids injected into the system by producers. The liquids are injected in low levels and can drop out of the stream flow and with the result that quantities build up over time. GasNet currently conducts periodic line valve syphoning to remove excess liquids from the pipeline low points. However, with greater diversity of markets and supply sources and the tendency for plants to operate at peak capabilities, higher levels of liquid carry over can be anticipated in the future. Therefore, GasNet proposes to install liquid removal facilities at each of these stations.

In addition, the Wollert city gate is in need of major re-engineering to rationalise and upgrade the equipment and controls.

Wollert Compressor Station automation

The Wollert compressor station requires an upgrade to the control system to allow reliable remote operation of the system by VENCorp. This follows the automation of the Gooding and Brooklyn compressors in 1999 and 2000. It is anticipated that the automation will be carried out during the summer of 2004/2005. The forecast cost for the automation is $2.7 million (2002 dollars).

Gas heaters at Dandenong, and Wollert and Tyers

GasNet proposes to install gas heaters at Dandenong, Wollert and Tyers in 2004. The forecast cost of the projects is $3.04 million (2002 dollars).

The *Gas Safety (Gas Quality) Regulations 1999* (Vic) and VENCorp "Gas Quality Guidelines" were amended in August 2000 to allow a broader range of gas qualities in the GNS. A consequence of this change is that there is now a higher probability that liquid condensates will form in the discharge from the pressure regulation stations.

To mitigate the risk of condensate drop out and maintain system capabilities, it will be necessary to install the gas heaters at the Dandenong, Wollert and Tyers regulator stations.

Gas chromatographs

VENCorp has pursuant to clause 4.3.3(a) of the MSO Rules directed GasNet to install three new chromatographs ("**GCs**") on its transmission system. These GCs have been identified by VENCorp as being required to calculate heating values for gas flowing at 3 particular stations with a sufficient degree of accuracy to allow the energy content of gas measured at affected offtakes to meet the accuracy required under the MSO Rules. The forecast cost of the

GCs is $0.90 million (2002 dollars). It is expected that this investment will be made in 2003.

Maintenance capex

GasNet has included an allowance in each regulatory year for maintenance capital expenditure. Total forecast maintenance capital expenditure is $5.66 million (2002 dollars). This includes IT upgrades (both hardware and software), upgrading assets which have shorter lives than the main assets (such as cathodic protection units, station instruments, electronic systems, heat exchangers) and the acquisition of field and workshop equipment.

3.7 Summary of components of revenue requirement

Table 3-11 summarises each of the components that make up GasNet's revenue requirement.

Table 3-11: Summary of Components of the revenue requirement

Components of Revenue Requirement	2003	2004	2005	2006	2007
Return on assets	33.4	33.1	32.9	33.0	32.9
Depreciation	20.6	21.5	22.5	23.4	23.7
Non-capital costs	32.9	20.6	20.3	22.0	22.3
Total	86.9	75.2	75.7	78.3	78.9

To create a smooth pricing path, tariffs in each year after the first year of the Access Arrangement Period are escalated by the factor CPI-X. Consequently, forecast revenue calculated on the basis of tariffs multiplied by volumes will differ from the target revenue determined under the Cost of Service Methodology. The initial tariffs and the X value are set so that the NPV of the forecast revenue stream is the same as the NPV of the target revenue. The target revenues and forecast revenues for the five year regulatory period are set out in Table 3-12 below.

Table 3-12: Target and Forecast Revenue ($million)

Year ending 31 December	2003	2004	2005	2006	2007
Revenue requirement ($m)	86.9	75.2	75.7	78.3	78.9
Forecast Revenue ($m)	80.2	78.8	77.8	79.2	80.3

4 Volume Forecasts

4.1 Peak demand 1998 - 2002

The peak demand and total annual delivered volume for the period 1998-2002 is set out in Table 4-1.

Table 4-1: Historical volumes 1998-2000[3]

Demand and volume	1998	1999	2000	2001	2002 (forecast)[4]
Peak Demand TJ/d	1006	911	1153	990	1121
Annual volume (PJ)	192.5	198.6	210.5	210.4	211.2

4.2 Peak demand 2003-2007

The forecast peak demand and total annual delivered volume for the period 2003 to 2008 is set out in Table 4-2.

Table 4-2: Forecast demand 2005-2007[5]

Demand and Volume	2003	2004	2005	2006	2007
Peak Demand (TJ/d)	1132	1174	1209	1235	1257
Annual Volume (PJ)	216.2	225.3	232.7	237.2	241.3

4.3 System load profile

The system load profiles in each pricing zone during 2001 are shown in the Table 4-3.

Table 4-3: Total Deliveries by month 2001 (TJ)

2001 ANNUAL VOLUME													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
La Trobe	1,085	950	880	919	985	972	1,023	1,216	990	953	974	847	11,793
Lurgi	70	56	73	89	115	136	166	179	142	152	123	116	1,416
Metro	8,883	9,075	10,978	12,598	18,245	18,766	20,299	19,826	14,090	13,468	11,653	10,966	168,846
Calder	321	346	485	614	871	981	1,060	1,039	753	756	619	511	8,355
South Hume	24	24	35	51	80	92	100	100	67	60	47	37	717
Echuca	411	567	640	504	496	500	413	502	463	496	425	405	5,822
North Hume	307	324	392	435	642	722	778	735	540	509	423	356	6,163
Carisbrook	24	27	32	48	69	80	87	87	62	59	48	39	659
Murray Valley	27	26	33	39	57	64	64	66	51	61	55	39	583
Barnawartha	461	941	386	160	66	66	40	48	43	6	31	33	2,281
WTS	240	196	222	220	271	325	383	404	371	416	389	359	3,795
TOTAL	11,852	12,533	14,156	15,675	21,896	22,704	24,413	24,202	17,571	16,936	14,785	13,707	210,430

4.4 Annual volume across each pricing zone

The actual and forecast annual volumes across each pricing zone are set out in Table 4-4 below.

[3] The historical volumes are not weather normalised and exclude refill volumes.

[4] This figure is based on the VENCorp forecast.

[5] The forecast volumes have been weather normalised.

Table 4-4: Actual and forecast annual volumes (TJ)

ANNUAL VOLUME BY TUoS ZONE										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
	ACTUAL				FORECAST					
La Trobe	Zone data not available as CTM network not yet operational	10,480	4,003	11,824	12,015	11.881	14,378	17,353	17,869	18,183
Lurgi		1,389	1,497	1,414	1,478	1,517	1,560	1,607	1,656	1,707
Metro Nth West		162,458	168,257	168,982	169,250	91,083	93,424	95,295	96,716	98,395
Metro Sth East						79,400	81,446	82,793	83,905	84,460
Calder		8,298	8,263	8,376	8,561	9,643	10,025	10,311	10,553	10,732
South Hume		787	712	719	810	839	870	894	915	929
Echuca		4,696	5,500	5,832	6,532	6,780	7,065	7,240	7,377	7,427
North Hume		5,739	6,116	6,186	6,703	2,122	2,212	2,266	2,308	2,320
Carisbrook		937	576	661	760					
Murray Valley		162	381	589	829	1,094	1,364	1,608	1,849	2,127
Barnawartha		68	1,384	2,290						
Wodonga						4,707	4,754	4,801	4,849	4,898
Tyers						2,267	3,131	3,253	3,675	4,299
SWP				173	153	583	586	590	694	797
Warrnambool							1413	1,472	1,533	1,596
Koroit							838	871	905	938
WTS	3,339	3,573	3,809	3,794	3,751	3,931	1,856	1,932	2,010	2,089
TOTAL	189,135	198,586	210,496	210,430	210,841	215,844	224,921	232,287	236,816	240,894

4.5 Forecast injection volumes

The non-coincident average of the 10 peak injection volumes at each tariffed injection point are set out in Table 4-5 below.

Table 4-5: Forecast Peak Day Injection

TJ/Day	**2003**	**2004**	**2005**	**2006**	**2007**
Longford	826	841	841	841	841
Culcairn	17	17	17	17	17
Port Campbell	176	170	172	194	208
Yolla	0	60	60	60	60
LNG	10	10	10	9	10

The Port Campbell injection volumes exclude volumes injected to the Western Zone which are not subject to the injection tariff.

5 Reference Tariff Calculation

5.1 Tariff Design Principles

The tariff design for the Second Access Arrangement Period is structured along the following principles, which are unchanged from the existing design except where noted.

(a) The system is divided into withdrawal zones, where a charge is levied on the withdrawing User, and injection points, where the charge is levied on the injector. In respect of the actual charges to be levied on Users, there is no assumed relationship between injections and withdrawals, except in certain zones where matched tariffs are offered. This corresponds to the Market Carriage structure, where Users can inject and withdraw as they please, with any differences taken to be purchases (or sales) on the spot market.

(b) The injection point charge recovers the cost of the injection pipeline. The withdrawal charge recovers the cost of transmission from the injection pipeline to the User.

(c) The cost of transmission through the withdrawal zones is based on a forecast of physical flows. Gas is assumed to have followed the physical path even if it was injected at a different injection point.

(d) Costs are allocated to 1 in 2 winter peak flows and annual flows in the ratio of 60% to peak and 40% to annual. This differs from the current model which allocates 65% of costs to the 1 in 20 winter peak flow.

(e) Withdrawals are charged within 16 withdrawal zones (an increase over the current 12 zones to reflect System expansion and the need for prudent discounts).

(f) Within each withdrawal zone there are up to 3 tariff classes. The existing tariff classes of Tariff-D and Tariff-V are supplemented by a storage refill tariff.

(g) Injections are charged at each of the injection points.

(h) The injection charge is levied on the ten peak injection days over the winter at each injection point (as compared to the current charge levied on five peak days).

(i) The withdrawal charge is levied on the actual flows each month (an "Anytime" charge). A different withdrawal charge applies to each tariff class.

(j) There is no "wash-up" procedure on withdrawal charges. However, to provide a smoother payment schedule for Users, injection charges will be forecast for each injector and levied monthly on a sculpted profile. An injection charge wash-up will be performed after September each year when the actual peak days are known.

5.2 Tariff Derivation Procedure

In broad terms, the tariff is calculated using the following procedure.

(a) The peak and annual flows at each off-take are forecast for the Access Arrangement Period.

(b) Costs are allocated to each off-take using the procedures described in section 5.3 below. The allocation is to each tariff class at each off-take. The tariff classes are defined below in section 5.6.

(c) The costs at each off-take are aggregated into the 16 withdrawal tariff zones and the injection pipelines.

(d) The parameters for charging tariffs on the injection pipelines and within the withdrawal zones are defined in section 5.4 and 5.5 below.

(e) The tariff is the result of dividing the charging parameters into the allocated costs for each injection pipeline and withdrawal zone. These tariffs are levelised over the period 2003-2007 using the nominal vanilla WACC at the selected X-factors. The selected X-Factors are described in section 5.10 below.

5.3 Cost Allocation Procedures

This section describes how costs are allocated to specific off-takes and tariff classes.

Cost are grouped into the following categories, and allocated as shown in Table 5-1.

Table 5-1: Cost Allocation Procedure

Cost Category	Allocation Method
System Assets (return on and of capital) (excluding the SWP, Murray Valley and Interconnect Assets)	Physical path
Direct Operating Costs[6]	Physical path
Costs rolled in under Economic Feasibility Test (SWP, Interconnect & Murray Valley)	Direct to zone
Costs rolled-in under the System-Wide Benefits Test (SWP & Interconnect Assets)	Postage Stamp
Non-System Assets[7] (return on and of capital)	Postage Stamp
General & Administrative Operating Costs	Postage Stamp
Return on Working Capital	Postage Stamp
K-Factor Carry-Over	% Increase
Asymmetric risk	Postage stamp
Capital raising costs	Physical path

Physical Path Cost Allocation

The aim of this cost allocation procedure is to allocate costs to each User in proportion to that User's use of the transmission system assets. Therefore, a User who uses a short section of the system will, in general, pay a lower cost than a User who uses a longer section of the system.

The specific assets that are used by a User are determined by the physical path taken by the gas flow from the relevant injection point to the User's off-take. The relevant injection point for each off-take is determined by a process of allocating the forecast injection volumes from each injection point to the off-takes based on the physical flow dynamics of the system, until the injection volumes have been exhausted. The majority of the system is assumed to be supplied from Longford, since this is where the greatest

[6] Direct Operating Costs are the O&M costs less the General & Administrative (or corporate overhead) costs.

[7] Non-System Assets cover land, buildings and office equipment associated with G&A activities.

volumes are injected. To the extent that the injection volume forecast is changed, the physical paths will also change.

The transmission system has been divided into 27 pipeline segments, determined by the points at which pipeline diameter changes. Certain pipeline segments are associated with compressors and in-line system regulators. The cost that is associated with each asset (except for those rolled in under the economic feasibility test) segment is determined by a procedure that avoids vintage effects, as follows:

(a) the total return on and return of assets is determined for all of the pipeline, regulator and compressor assets;

(b) this cost is allocated amongst the pipeline segments and compressors according to the Optimised Replacement Cost (ORC) of each asset; and

(c) the direct pipeline operating costs are allocated to each pipeline segment according to the pipeline length. Compressor and regulator operating costs are allocated to each unit directly.

Capital raising costs are allocated on the same basis.

This procedure effectively disregards the vintage of each asset. It also means that refurbishments of the system, such as the Gooding and Lurgi pipeline refurbishments, are allocated across the entire system rather than to specific zones (however capacity augmentations are allocated to the associated pipeline segment in line with the incremental pricing principle in section 8.16 of the Code). This procedure, which is employed in the existing tariff design, is intended to reflect the principle that the tariff for a segment of pipeline should be related to its service potential, and not to its age.

In contrast to the existing tariff methodology, GasNet will allocate direct operating costs to the injection pipelines[8], including compressor maintenance and fuel costs where relevant.

Allocations to Peak and Annual Flows

Costs are allocated to Users on the physical path according to the peak and the annual flows through each asset group, where the peak flow is measured as the peak 1 in 2 day flow. The allocation of costs is in the ratio of 60% to the peak flow and 40% to the annual flow. GasNet has allocated costs on the injection pipeline based on the peak flows and allocated costs on the remainder of the system in the ratio of 55% to annual flows and 45% to peak flows (generating an average peak allocation of 60%).

Incremental Pricing of the Murray Valley Pipeline

The Murray Valley pipeline supplies gas to four townships in the Murray Valley region from a connection at Chiltern Valley on the main Wollert to Wodonga pipeline. The tariff for the Murray Valley withdrawal zone consists

[8] Indirect costs are all allocated to withdrawals.

of the sum of the tariff on the pipeline itself, plus the tariff to carry gas to Chiltern Valley from the north or from the south, depending on where the gas is injected. The design of the tariff to Chiltern Valley is based on the principles described above. However, the tariff on the pipeline itself is designed to recover the incremental capital and operating costs associated with the Murray Valley pipeline lateral over the life of the asset, such that the tariff satisfies the Economic Feasibility Test.

Under the arrangements applying from 1998 to 2002, the costs on the Murray Valley pipeline lateral were recovered from the peak day flows. Under the revised arrangements applying from 2003 to 2007, the costs will be recovered from annual flows, with a distinct tariff for Tariff-D and Tariff-V customers. The Tariff-D and Tariff-V rates are determined by allocating 75% of the revenue requirement to the forecast peak flows for each of Tariff-D and Tariff-V, and 25% to the forecast annual flows. The peak/annual allocation ratio of 75:25 is greater than the allocation ratio of 55:45 used on other withdrawal pipelines, but it was determined that a shift from the current peak allocation to the 55:45 ratio would lead to tariff shock for Murray Valley pipeline customers.

Cost Allocation to Off-takes within Pipeline Segments

Within individual pipeline segments, costs are allocated on the basis of the volumes and distances (TJ-km) flowed within the zone for both the outflows at each off-take and for the flows through the zone. This allocation is done for both peak and annual flows in the ratios discussed above.

The costs are then allocated to each tariff class within a zone as follows:

(a) a rate ($/TJ/km) is derived for both peak and annual supply at each off-take based on the TJ-km for both peak and annual flows within the zone to each off-take and through the zone;

(b) a forecast is made of the Tariff-V and Tariff-D loads at each off-take and the separate components of peak and annual flows within each tariff class;

(c) the peak and annual rates are applied to the associated components of the Tariff-D and Tariff-V loads at each off-take, to derive the costs to be allocated to these tariff classes at each off-take; and

(d) the costs within withdrawal zones are aggregated for each tariff class to the zonal level. The total costs within the injection pipelines are aggregated to generate the total injection pipeline cost.

SWP

A separate regime applies to the SWP, being an injection tariff to recover the entire cost of this pipeline, as discussed in section 5.7 below. The relevant costs that must be recovered from the injection tariff are the asset costs (return on and of capital) and the incremental operating costs associated with the SWP project. This is a direct allocation procedure and the allocation procedure discussed above is not applied to the SWP.

Wollert-Wodonga Pipeline

The Wollert-Wodonga Pipeline supplies the South and North Hume zones, a large part of the Calder zone, the Murray Valley Pipeline, the Echuca zone, Wodonga and potential exports to NSW. This pipeline also enables imports of gas from Culcairn to the northern zones.

GasNet is offering source-based tariffs in the North Hume, Interconnect, Wodonga and Murray Valley pipelines. That is, there is a relatively high tariff for supply from the south, and a separate discounted tariff for supply from Culcairn, which reflects the significantly shorter transportation distance from Culcairn compared to transportation from the south.

GasNet has calculated the tariffs in these zones as follows. Firstly, the tariffs for supply from the south have been calculated from the recovery of the revenue requirement for each asset group assuming complete supply to these zones from the south (that is, ignoring the fact that actual northerly flows are reduced by flows from Culcairn). This tariff methodology is consistent with the methodology used on the rest of the system, assuming that gas actually flows to these zones from the south. These tariffs exceed the long-run marginal cost of supply on the Wollert-Wodonga pipeline, as determined from an economic analysis of an incremental capacity augmentation of the pipeline described in the VENCorp APR (section 5.3.3).

Tariffs from Culcairn are evaluated based on the forecast flows and the same pipeline unit transportation costs as determined by the southerly supply scenario. In the case of Wodonga, a small prudent discount is also required to avoid a bypass opportunity. However, because the actual forecast revenues are a combination of Longford supplied revenues and discounted revenues from Culcairn sourced gas deliveries, the total revenue recovery is insufficient. Hence the path-based tariffs on the rest of the system have been marginally increased by approximately $0.01/GJ to recover the shortfall.

Culcairn Withdrawal Tariff

While GasNet is not forecasting exports from Culcairn to NSW, it is necessary to publish a tariff in the event that a flow reversal occurs through the Interconnect pipeline. A properly cost-reflective tariff must recognise the increased flows on the Wollert-Wodonga pipeline that would result if gas were to be exported to NSW. GasNet has calculated a notional tariff based on an increase in northerly flows of 3 PJ per annum, and has applied this to an export volume with an 80% load factor.

Indirect Cost Allocation (Postage Stamp)

The indirect costs are the costs associated with the Non-System Assets (return on and of capital), the return on Working Capital and the General & Administrative operating costs. In line with the existing tariff model, these costs will be allocated to all withdrawals on a per GJ basis.

Where a prudent discount is required, GasNet has only allocated indirect costs to the extent that the tariff is competitive with the bypass option.

Interconnect and Springhurst Compressor

The Interconnect Assets were approved by the Commission in April 2000 to be rolled-in to the GasNet Capital Base under the test in section 8.16(b)(ii) of the Code (often called the system-wide benefits test). The relevant assets are:

(a) the bulk of the Interconnect Pipeline (92%);

(b) the Springhurst Compressor; and

(c) the regulators at Wandong, Barnawartha, Wollert and Ballan.

The remaining 8% of the cost of the Interconnect pipeline is treated as a direct asset recovery for the Culcairn injection tariff.

The Commission's approval permitted GasNet to charge for these assets under a postage-stamp tariff on all withdrawals from the system, with the exception of the WTS.

GasNet proposes to continue with this allocation procedure. However, where a prudent discount is offered, the allocation will be reduced as required.

K-Factor Carry-Over

The K-Factor Carry-Over is a cost which is associated with activities during the First Access Arrangement Period, but which can be carried forward into the Second Access Arrangement Period. The K-Factor to be carried forward into the Second Access Arrangement Period is $12.9 million. This amount will be allocated to all tariffs (other than the SWP) as a uniform percentage increase.

Across System Flows

GasNet has adopted a policy of no backhaul charges for flows against the predominant (forecast) flows on injection pipelines. However, as current tariffs stand, a flow from Longford to Iona would only attract the Longford injection charge plus the local withdrawal charge on the SWP. Similarly, a flow from Iona to Longford would only attract the Iona injection charge plus the local withdrawal charges off the Longford pipeline. GasNet will levy an additional charge for carriage through the Metro zone, for withdrawals off the injection pipeline which are linked to injections at an unrelated injection point. This charge will be the Metro zone tariff discounted for the indirect cost allocations (which are already recovered from the withdrawal zones).

5.4 Charging Parameters – Withdrawal Zones

GasNet will charge a flat "Anytime" rate for all withdrawals, to be levied monthly on actual flows, with a specific rate determined for each tariff class, as discussed below in section 5.6 below.

5.5 Charging Parameters – Injection Pipelines

Longford Injection Charging Parameter

The Longford injection charge will be levied on the ten peak day injections into the pipeline over the winter period (June-September, inclusive).

Withdrawals made in the LaTrobe, Tyers, Lurgi or West Gippsland zones which are matched to Longford injections on the ten peak injection days will receive a lower injection charge based on the shorter transmission distance on the injection pipeline.

Port Campbell Injection Charging Parameter

The Port Campbell injection charge will be levied on the ten peak day flows through the Iona-Lara pipeline over the winter period (June-September, inclusive). These flows will be calculated from the total injections made within the Port Campbell injection zone, less the withdrawals from the WTS or other off-takes at or in the vicinity of Port Campbell.

A lower injection charge will apply for withdrawals from the SWP where the withdrawal can be matched to an injection at Port Campbell.

Culcairn Injection Charging Parameter

The Culcairn injection charge will be levied on the ten peak day injections into the Interconnect Pipeline over the winter period (June-September, inclusive).

A lower injection charge will apply to injections matched to withdrawals in the Wodonga, North Hume, Murray Valley and Interconnect zones.

5.6 Tariff Classes

GasNet will charge a differential withdrawal tariff in relation to Tariff-V and Tariff-D customers to reflect the significantly different load factors for these customer classes. GasNet also proposes to introduce a new tariff class, the Storage Refill Tariff.

In relation to Storage Refill, GasNet will charge the marginal cost of refill, which is principally the cost of additional compressor fuel required to deliver gas to the storage.

5.7 Incremental Pricing of the SWP

Proposal

The SWP will be allocated 50% of the full direct costs of the SWP assets, being return on and of capital and the incremental operating costs. The remaining 50% will be recovered through an increase in withdrawal tariffs throughout the GNS.

The SWP is expected to carry significant volumes from Iona to Melbourne. GasNet will tariff the SWP as an injection pipeline and apply an injection charge in a similar manner to the injection charge applied to the Longford pipeline (based on the ten peak day flows at the injection point).

Currently, the injections into the SWP are made at the WUGS facility at Iona, which has sufficient installed compressor power to inject gas at the maximum allowable operating pressure of the Iona-Lara pipeline of 10 Mpa. However, in future it is anticipated that there will be a number of other connection points established in the vicinity of Iona which will be capable of injections into the SWP. These connection points will access gas from the new fields being developed at Port Campbell (Santos), Minerva (BHPP), and Thylacine - Geographe (Origin/ Woodside).

Therefore GasNet will levy the injection tariff on any injections made in the vicinity of Iona, where the gas is directed along the SWP towards Lara.

Where the gas is directed to the WTS, (that is, where the injections are matched to withdrawals in the Western zone) or off-takes adjacent to Iona, no injection charge will be levied (however, the South West zone withdrawal tariff or the Western zone withdrawal tariffs will apply, depending on where the withdrawals are taken out of the system).

Revenue Requirement

GasNet is conscious of the fact that the SWP is a new pipeline in competition with other gas injection pipelines, and that a reasonable tariff is required in order to encourage growth on the pipeline.

Therefore, in addition to the allocation of 50% of the revenue requirement to withdrawal tariffs, GasNet has taken two initiatives to generate the lowest possible tariff on the pipeline.

(a) The economic life of the SWP is set to end in 2052. This is almost 20 years longer than the economic life of the rest of the GasNet pipelines, which will impose a greater level of risk on GasNet.

(b) The revenue requirement relating to the SWP is levelised over the first 20 years at a flat real rate. This has the effect of deferring revenue recovery to the future, on the assumption that the volumes will grow faster as a result of the lower tariff. Based on this levelisation procedure, the depreciation allowance in the early period of the life of this asset is reduced as GasNet defers capital recovery on the pipeline over time in order to encourage future utilisation.

Port Campbell Injection Tariff

The injection tariff is derived by applying a CPI-X tariff path to the charging parameter for the Port Campbell injection zone. The initial tariff is set so that the NPV of the tariff revenues equates to the NPV of 50% of the levelised revenue requirement for the SWP.

Revenues from the WUGS storage refill are not included, as these are designed to match the marginal supply costs from operation of the Brooklyn compressor station.

An allowance is made for revenues from Colac on the Iona-Lara pipeline, which will receive a matched injection charge owing to its location on the pipeline.

5.8 Incremental Pricing of the Interconnect Pipeline

Revenue requirement

The Interconnect pipeline carries gas from the Culcairn injection point to Barnawartha, where it joins the North Hume and Wodonga zones.

The Interconnect Pipeline has been allocated 8% of the direct cost of the Interconnect Pipeline. The remaining 92% and the operating costs are recovered under a postage stamp tariff as approved by the Commission in 2000.

The revenue requirement for the Interconnect Pipeline is calculated using a real, straight-line depreciation profile, as for all other assets in the GasNet system with the exception of the SWP.

Culcairn Injection Tariff

The allocated costs of the Interconnect pipeline are recovered entirely from the Culcairn Injection Tariff. The injection tariff path is derived by applying a CPI-X tariff to the charging parameter for the Culcairn Injection Point. The initial tariff is set so that the NPV of the tariff revenues equates to the NPV of the Interconnect Revenue Requirement.

Matched Rebates

Off-takes on the Interconnect pipeline are offered a reduced injection charge if the injections are matched to the withdrawals.

5.9 Tariff Zones

Retain existing zones

In the interests of consistency and stability across Access Arrangement periods, GasNet has maintained the current tariff zones. However, GasNet has divided some zones for the purpose of offering a more cost-reflective tariff, where bypass opportunities have been identified. These new zones are described below.

Tyers zone

The current LaTrobe zone includes the large 500 mm lateral from Tyers to Morwell. This asset is effectively charged to all other off-takes within the zone, most of which are directly connected to the Longford injection pipeline. This creates a bias which increases the bypass risk within the LaTrobe zone. Therefore, the Tyers to Morwell pipeline will be separated as a new zone. The main Users on this lateral are the Morwell township and the Jeeralang and Loy Yang power stations.

Wodonga zone

Wodonga is at the extreme northern end of the long North Hume zone and is the largest load in the region. A high pressure distribution pipeline runs from the GasNet off-take through the city and north to the paper mill operated by Norske Skög. The location of this pipeline means that a bypass pipeline could be constructed from Culcairn directly to the plant and into the Wodonga distribution network. Therefore GasNet has separated the short pipeline from Barnawartha to Wodonga as a new zone. A prudent discount will be offered for injections made at Culcairn, as discussed below.

Metro South East zone

There is a prospect of a new injection point at Pakenham, which would take gas transported from a new field development at Yolla, via a gas processing plant at Lang Lang.

When this project is commissioned, the proponents would have the opportunity to bypass the main GasNet pipeline between Pakenham and Dandenong, and connect directly to the large distribution off-takes at Dandenong (thereby avoiding both the GasNet system and the VENCorp spot market). As the gas distribution systems in Melbourne are interconnected, it is possible that gas from Pakenham could be delivered via Dandenong and nearby offtakes to any gas consumer south of the Yarra River.

Thus, GasNet will offer a prudent discount by defining a new Metro South East Zone where the bypass tariff will apply. This discounted withdrawal tariff will only apply to matched injections at Pakenham. The Pakenham injectors will also attract a discount on the Longford injection tariff commensurate with the distance between Pakenham and Dandenong.

West Gippsland zone

Currently there are no off-takes on the main pipeline between the LaTrobe and Metro zones. However, in the event that a connection is made in the future, a published tariff will be defined for this zone.

Warrnambool and Koroit

The WTS will be covered by this Access Arrangement from 2003 and will be designated the “Western zone”. The WTS serves five towns along the length of the pipeline, and carries a volume approaching 4 PJ/year.

An interstate pipeline is expected to be built between Iona (or nearby location) and Adelaide by 2004. This pipeline is likely to be installed within the same easement as the WTS for part of its length, and will pass two towns currently served by the WTS.

There is a bypass opportunity at these towns, and GasNet will offer a prudent discount from 2004 as described below. GasNet will not define a new zone, but the two at-risk towns will receive a special published tariff.

5.10 The X-Factor and the Initial Tariffs for 2003

GasNet’s tariffs are designed to follow a CPI-X price path. This means that the forecast tariff components are escalated annually by the factor

Forecast CPI * (1-X).

The initial tariff components are calculated so that the total revenues derived by applying the forecast tariff components to the relevant forecast volume components, has the same NPV over 2003 to 2007 as the forecast target revenues.

The actual escalation of each tariff component is described in Schedule 4 of the Access Arrangement.

The X-Factor is derived as follows:

(a) an initial estimate of the X-Factor is postulated;

(b) starting values for 2003 injection and withdrawal tariffs are postulated for each zone;

(c) the tariffs are escalated at (1+CPI)*(1-X) for five years, and applied to the forecast volumes to generate the anticipated revenue from each zone;

(d) the starting tariff values are adjusted so that the NPV of the costs allocated to each zone over the five year period is equal to the NPV of the anticipated revenues within each zone;

(e) the X-Factor is consistent across all tariffs, except in some zones where special outcomes are sought; and

(f) if the starting tariffs are considered to have shifted too far from 2002 levels, then a revised X-Factor is chosen, and the process is repeated. Consideration is also given to the longer-term trends in tariffs, with a view to avoiding tariff shocks at the next tariff revision.

GasNet has decided to use a zero X-Factor for the Murray Valley zone in order to encourage connections to natural gas. A zero X-Factor is also applied at Wodonga and the Western Zone towns of Warrnambool and Koroit, where prudent discounts have been applied, for refill tariffs, which are directly related to the incremental cost of the service.

With these exceptions, GasNet has applied an X-Factor of 3 % for all remaining tariffs.

5.11 Prudent Discounts

LaTrobe Zone Discount

The LaTrobe withdrawal zone is a 65 km pipeline from Longford to the end of the duplicated section of the Longford injection pipeline, just short of the Gooding compressor station. The zone contains the towns of Sale, Rosedale, Traralgon, and the large Paper-Linx paper plant at Maryvale. There is also a private pipeline lateral to the Edison Mission peaker plant. The only physical GasNet withdrawal asset within the withdrawal zone is the short lateral to Maryvale.

The customers at these off-takes must pay the Longford injection charge (discounted to reflect the lower transportation distance) plus a withdrawal charge that recovers the cost of the zonal assets and a contribution to overheads.

It is relatively straight-forward to construct a bypass pipeline from Longford to Maryvale, servicing the towns en route. GasNet has designed and costed such a bypass pipeline, and calculated an estimate of the bypass tariff. Since VENCorp is not proposing to discount its tariff, GasNet has derived the prudent discount by deducting an amount equal to the forecast VENCorp fees and charges.

Based on this analysis, the proposed GasNet discounted withdrawal tariff is:

Tariff-D $0. 0456/GJ in 2003

Tariff-V $0. 0611/GJ in 2003

These tariffs escalate at CPI-3% because the bypass risk increases as the load grows over time (reflecting the economies of scale in pipeline construction).

Analysis shows that the calculated bypass tariff exceeds the combination of the injection charge and the withdrawal charge, if overhead allocations are excluded. Therefore GasNet believes the discount is prudent.

The LaTrobe matched injection tariff will be retained, and the LaTrobe withdrawal zone tariff will be adjusted down to give a combined injection and withdrawal tariff equal to the prudent discount.

Wodonga Prudent Discount

Albury/Wodonga is currently supplied from the GasNet system at Wodonga. The city gate is approximately 10 km from the point where the Interconnect pipeline joins the main Wollert-Wodonga pipeline.

The Wodonga gas volume is approximately 5.0 PJ/year and growing. The largest industrial consumer is the ANM paper plant (now owned by Norske-Skög), which is located to the north of the city of Albury/Wodonga. It is supplied by the Origin Energy distribution pipeline which runs from the Wodonga city gate, under the Murray River, and through the city proper, before terminating at the plant.

It is possible to connect directly to the ANM plant and the Origin distribution system by constructing a 41 km bypass pipeline from Culcairn. This poses an immediate bypass threat.

GasNet has evaluated the cost of a bypass pipeline and derived the bypass tariff. VENCorp is not offering a discount on the VENCorp fees, so an amount equal to the VENCorp tariff has been deducted to give the following discount tariffs:

Tariff-D $0. 1002/GJ in 2003

Tariff-V $0. 1298/GJ in 2003

The marginal cost tariff is the sum of the Culcairn injection tariff, and the Wodonga withdrawal tariff, excluding allocated overheads. This tariff is significantly less than the required discount tariff, therefore the discount can be considered as prudent.

The tariff will be implemented by adjusting down the withdrawal tariff for the Wodonga zone (by allocating a lower share of overheads than other zones receive). The matched Culcairn injection tariff will be retained, and the withdrawal tariff will be set so that the combined tariff equals the prudent discount.

Western Zone Discount

The new Western Zone covers five towns in the Port Campbell to Portland area with consumption of approximately (forecast 2003) 4 PJ of gas. The system consists of 216 km of pipelines, and is valued at about $9m. The current tariff is approximately $0.50/GJ.

However there is a bypass threat posed by the proposed Iona to Adelaide pipeline. The Port Campbell to Adelaide pipeline follows the Western System easement past Warrnambool, and diverges towards Adelaide in the vicinity of Koroit. It passes the city gates for Warrnambool and Koroit.

The economies of scale of the South Australian pipeline are such that the owners can offer a significant discount over the current tariffs for the Western zone. However, there will be costs to install connections and regulators operating at 15MPa, which is the anticipated MAOP of the South Australian pipeline.

The volumes at Warrnambool and Koroit constitute 55% of the total volumes on the Western System. Therefore there is a significant bypass threat.

GasNet proposes to offer a prudent discount in the Western Zone . This will minimise the risk that the Western Zone customers will shift to the competing pipeline.

A bypass tariff can be calculated for each town under threat in the Western Zone . Based on these tariffs, one can calculate the maximum revenues that would be earned from the Western Zone at the discounted tariffs. These can be compared to the marginal costs of continued supply to the existing loads. If the discounted revenues exceed the marginal costs then a prudent discount can be offered.

GasNet considers that the towns of Portland, Cobden and Hamilton are not at risk of bypass under current load forecasts. However, the towns of Warrnambool and Koroit could access a better tariff from the Port Campbell to Adelaide pipeline than that offered on the GasNet system (under the standard cost allocation procedures on the GasNet system).

Analysis shows that an adequate discount can be offered by simply reallocating direct and indirect overheads away from the Western Zone . Therefore GasNet considers that the proposed discounts are prudent, and will offer a discount to the towns of Warrnambool and Koroit. In order to minimise the cost burden on other Users, GasNet will offer the discount only from 2004.[9]

[9] The prudent discount is offered on the LaTrobe and Wodonga zones from 2003 because the analysis shows that this is the efficient tariff. However the Western System bypass is not a case

The proposed prudent discount tariffs (in $2003) are:

Warrnambool

Tariff-D $0.0534/GJ

Tariff-V $0.0852/GJ

Koroit

Tariff-D $0.1502/GJ

Tariff-V $0.2032/GJ

These tariffs are escalated at CPI each year.

Dandenong Bypass Tariff

GasNet is aware of a proposal by Origin Energy to develop the Yolla offshore field in Bass Strait and to deliver this gas to Victoria by undersea pipeline. Current indications are that this gas will be processed at Lang Lang and delivered for injection into the main GasNet transmission pipeline at Pakenham.

It is GasNet's understanding that Origin plans to deliver up to 20 PJ/year (68 TJ/day) into the GasNet system from 2004. However Origin has the option to extend their transmission pipeline to Dandenong, located approximately 29 km from Pakenham. Dandenong is the site of a number of large off-takes into the Origin distribution network. Origin has the opportunity to bypass both the GasNet system and the VENCorp gas market.

GasNet has estimated the cost of a bypass pipeline and associated regulators and metering facilities at Dandenong, and calculated a bypass tariff between Pakenham and Dandenong. This tariff exceeds the marginal long-run tariff through the GasNet system, and therefore GasNet contends that this tariff will constitute a prudent discount.

The tariff is contingent on the project actually proceeding.

The tariff will be implemented as an injection tariff at Pakenham and a discounted withdrawal tariff south of the Yarra River in Melbourne (Metro South East withdrawal zone). The injection tariff is determined as a proportion of the Longford injection tariff, pro-rated on the distance between Pakenham and Dandenong. The remainder of the bypass tariff will be levied as a discount on the Metro South East withdrawal tariff.

Port Campbell to Adelaide pipeline

A consortium of companies is currently engaged in developing a transmission pipeline, to be known as the SEAGas pipeline, to export gas from the Port Campbell region to South Australia. This pipeline may be connected to the GNS at or near the WUGS facility at Iona.

of matching the efficient tariff. It is a response to the South Australian pipeline being constructed adjacent to a Western System pipeline.

The SEAGas off-take has not yet been constructed, but GasNet has been asked to consider the appropriate withdrawal tariff if SEAGas connected approximately 400 metres downstream of the TXU injection point in the WUGS facility. If gas were to be injected at WUGS and withdrawn at the SEAGas off-take then the injection charge would be zero, but the Withdrawal would be subject to the South West zone withdrawal tariff of approximately $0.11/GJ.

However, it is not certain that the SEAGas off-take would be located downstream of the TXU injection point. Recent negotiations between Origin and TXU have lead to an arrangement for both parties to share the SEAGas pipeline and it is now possible that the connection could be upstream of the TXU injection point.[10]

In the event that the connection is built on the GasNet system, the marginal costs of supply would very small. The appropriate tariff should be no less than the cost of constructing a bypass. While there are many uncertainties with this project, GasNet is of the view that a notional charge of $0.02/GJ, in addition to the VENCorp charge, would not be unreasonable.

SEAGas tariffs:

Injection	$0.0000 /GJ in 2003
Withdrawal	
Tariff-D	$0.0200 /GJ in 2003

VicHub Discount

Duke Energy is currently developing a hub facility at Longford to connect the GNS to its Eastern Gas Pipeline and the Tasmania Gas Pipeline.[11] The VicHub off-take is planned to be constructed approximately 20 metres downstream of the Longford injection point. It connects the GNS to the Duke EGP. GasNet has forecast that approximately 10 PJ per annum will be injected into the GNS from the EGP (sourced from the Baleen/Patricia fields). Under the standard tariff methodology, injections from VicHub pay the Longford injection charge

However, the facility also has the capability to withdraw gas from the GNS. If gas were to be injected at the Longford injection point and withdrawn from VicHub, the standard method would apply the Longford Injection tariff, discounted for withdrawals from the LaTrobe zone, plus the Latrobe Zone withdrawal tariff. The total tariff at 75% load factor would be approximately $0.066/GJ. To this would be added the VENCorp charges which are approximately $0.04/GJ.

[10] International Power Media Release, "*Major SEA Gas expansion to meet South East Australia's energy needs*" (4 Sept 2002) at www.originenergy.com.au/news/news_detail_php?pageid=83&newsid=205.

[11] Duke Energy International News Release, "*History made as natural gas flows to Tasmania*" (3 Sept 2002) at www.duke-energy.com.au/news/releases.asp.

Nevertheless, GasNet recognises the anomalous nature of this situation and believes it is reasonable to forgo the Latrobe withdrawal tariff. The injections at Longford would still pay the Longford Injection Tariff (discounted for withdrawals in the LaTrobe Zone), which is approximately $0.02/GJ at a 75% load factor. The VENCorp charge would continue to apply.

VicHub tariffs:	
Injection	$0.4597 /GJ in 2003
Withdrawal	
Tariff-D	$0.0000 /GJ in 2003

5.12 Tariff path

The GasNet Tariff employs a ‘price path’ methodology. This means that GasNet will specify:

(a) a set of initial tariff components applicable to the year 2003, and

(b) a procedure to adjust tariffs components, applicable to each subsequent year.

Once these elements have been determined, the initial tariff components and the tariff adjustment procedure are not altered over the term of the Second Access Arrangement Period, except through a revision application approved by the ACCC under section 2 of the Code.

The fixing of the price path constitutes an incentive mechanism. The tariff adjustment procedure is not altered if actual volumes or actual costs differ from the initial forecast, except as provided for in the pass-through procedures set out in the Access Arrangement. This methodology exposes GasNet to both volume and cost risk, and removes these risks from GasNet customers.

The extent to which GasNet is exposed to volume risk is determined by the mechanics of the tariff adjustment procedure. GasNet has chosen a price path based on a form of average revenue price control. This means that the tariff components will be set each year to achieve a prescribed average revenue. Therefore, the GasNet revenues are tied to the actual delivered volumes through the GasNet system, which may vary from the initial forecast values.

The average revenue price path is calculated in advance (in real terms) based on the forecast volumes and target revenues. These target average revenues are published in the tariff schedule for each year subsequent to 2003. The price path is locked-in except for annual adjustments for actual inflation, and to correct for any under- or over-recovery of revenues in the preceding year. This annual adjustment for the under or over-recovery of revenues in the previous year is called the K-factor. If GasNet under/over recovers revenues in a given year in relation to the prescribed average revenue for that year, then GasNet is permitted to increase/(decrease) tariff components in the subsequent year to correct for the under/over recovery.

GasNet has operated under a similar price control mechanism during the First Access Arrangement Period. However, as a result of individual tariff component rebalancing constraints, and given significant under-recoveries of revenue in each year, GasNet has accumulated a large correction factor which has not been recovered during the First Access Arrangement Period. GasNet proposes to relax these constraints in the Second Access Arrangement Period so that GasNet tariffs are able to be increased by up to 2% from the base tariff path.

With respect to the individual tariff components, the standard procedure is to escalate each component annually by the CPI-X factor, where there is a specific X for each tariff component. However, it is possible that this procedure will not lead to the correct average revenue, as described above (that is, the published average revenue, as adjusted for actual inflation and for any over/under recoveries from the previous year). This will require an adjustment to the tariff components. GasNet will, in the first instance, adjust the tariff components for any year by an equal percentage increase-(decrease) above the tariff components derived by applying the standard CPI-X formula to the previous year's tariff components. The adjustment will be made to ensure that the average revenue expected for that year will be equal to the published average revenue, adjusted for actual inflation, and for any over/under recoveries in the previous year. Because all tariff components are adjusted by the same percentage, the tariff relativities between customers will be maintained. Once this adjustment has been made, the results will be compared with the allowed total adjustment based on CPI-X+2%. If the adjusted tariffs are greater than allowed, they will be scaled back equally to the allowed increase. Any under recovery of revenue as a result of such a scaling back will be carried forward and can be recovered in later years.

However, GasNet also believes that it is appropriate to retain some flexibility to rebalance the relative weights of one tariff component against another, where for example GasNet believes that gas volumes are being inhibited by the tariff design. Given the overall average revenue target, GasNet will only benefit from this procedure where it believes that the volume growth (and hence welfare gain) expected from a reduction in one tariff component is greater than the volume decline expected from the increases in other tariff components.

Hence GasNet may, where the scaled adjusted tariffs are less than 2% above CPI-X, adjust any tariff component by up to 2% above the base tariff path of CPI-X. This will require a decrease in other tariff components to maintain the adjusted revenue at the same level.

If there is an under/over recovery in the final year of the Second Access Arrangement Period, then the correction will be carried forward into the Third Access Arrangement Period.

6 Key Performance Indicators

6.1 Key Performance Indicators

GasNet has collected data from seven Australian pipeline companies using information published in Access Arrangements and Access Arrangement Information submitted by those companies and in the Commission's draft and final decisions on those Access Arrangements. The data represents the forecast operating costs in 2003, net of working capital and compressor fuel costs.

Working capital costs have been excluded from the KPI statistics as they are unique to each pipeline company and are relatively small in magnitude.

Compressor fuel costs have also been excluded from the KPI statistics as these costs are not within the control of GasNet (compressor operations are controlled by VENCorp). A comparison of compressor fuel costs is also complicated by the fact that other pipeline companies have a range of inconsistent methods to fund the cost of compressor fuels (for example, some companies require the shipper to provide the fuel used in operations).

Maintenance capital expenditure has not been included within the review of operating expenses. GasNet submits that, although maintenance capital expenditure and operating expenditure are to some extent interchangeable, the level of capital expenditure is very small (and will be until transmission assets are near the end of their operating lives) and that where maintenance capital expenditure is required, the projects can be identified and justified on a case by case basis.

GasNet's forecast costs for 2003 have been adjusted to provide for a fairer inter-company comparison. Firstly, an allowance for gas control has been added to GasNet's costs (a function that other companies perform but which is performed by VENCorp on the GasNet system), and the large increment in insurance cost has also been excluded for the purposes of inter-company comparisons.

Cost comparisons between companies require the use of normalising factors which, to the extent possible, attempt to place the companies on a common footing. The normalising factors consist of various measures of workload and attempt to represent the cost drivers of a particular company.

KPIs are only relevant to the extent that the cost drivers are correctly selected and applied. The value of KPI analysis is limited to the extent that the relevant cost driver is not always available for all companies in the sample.

Different activity costs incurred by GasNet will be subject to different cost drivers. Therefore, in many cases, the costs should be broken down into the main activities and the appropriate driver selected for each activity. Unfortunately, there is limited disaggregation of the data available in public documents. The publicly available data consists of "General and Administrative" (G&A) costs (also known as general overheads) and "Operating and Maintenance Costs" (O&M).

Publicly available data in relation to the Moomba-Adelaide pipeline was limited to total operating costs (ie it was not disaggregated into G&A and O&M). Therefore, GasNet has only included this pipeline in the KPIs relating to total operating costs.

GasNet has employed drivers suggested by the benchmarking consultants and those employed in previous Access Arrangement submissions.

GasNet has collated the following KPIs based on publicly available data:

(a) operating costs per GJ of gas delivered;

(b) operating costs as a percentage of capital investment;

(c) O&M costs per metre of pipeline;

(d) G&A costs per GJ of gas delivered; and

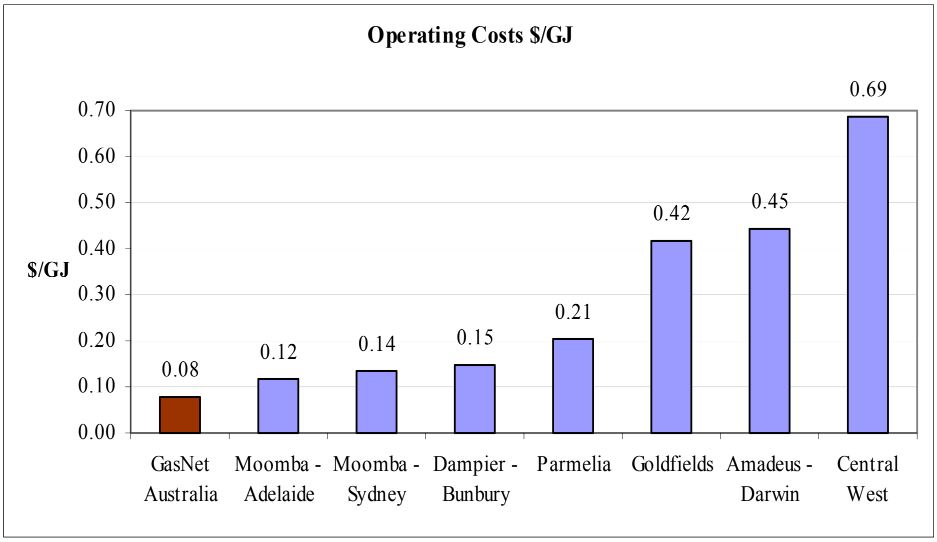
(e) O&M costs as a percentage of capital investment.

There is no disaggregated data in the sample in relation to compressor maintenance costs. However, GasNet has calculated its compressor costs as a percentage of the capital invested in the compressors as discussed below.

Operating costs per GJ of gas delivered

Gas deliveries is the simplest measure of the output of a transmission company. Figure 6-1 below illustrates that on this broad measure of efficiency, GasNet is one of the leading companies.

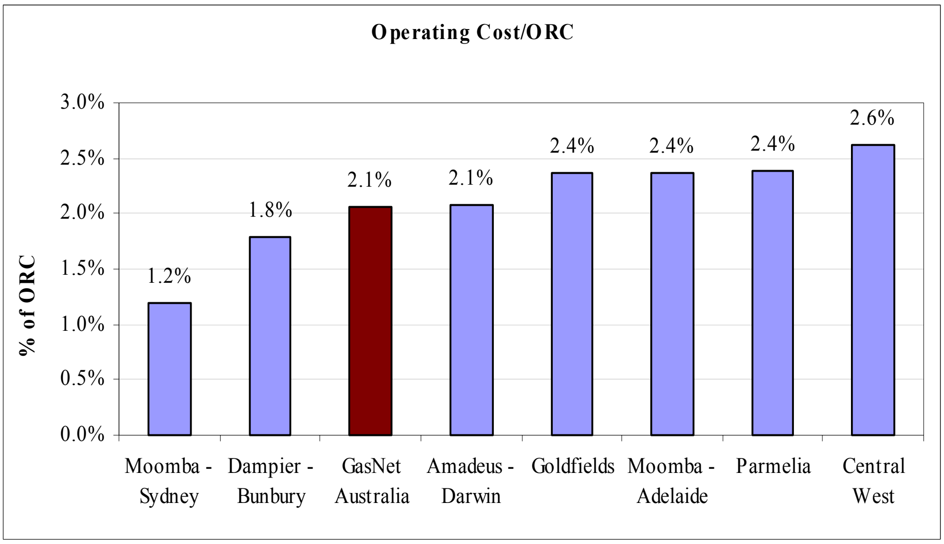
Figure 6-1: Operating costs per GJ delivered



Operating costs as a % of capital investment

Another measure of efficiency is operating costs as a percentage of capital investment. This measure capture both the length of the pipeline system, and the number and size of the compressor stations installed. As indicated in Figure 6-2 below. GasNet performs well in relation to other Australian pipeline companies on this measure.

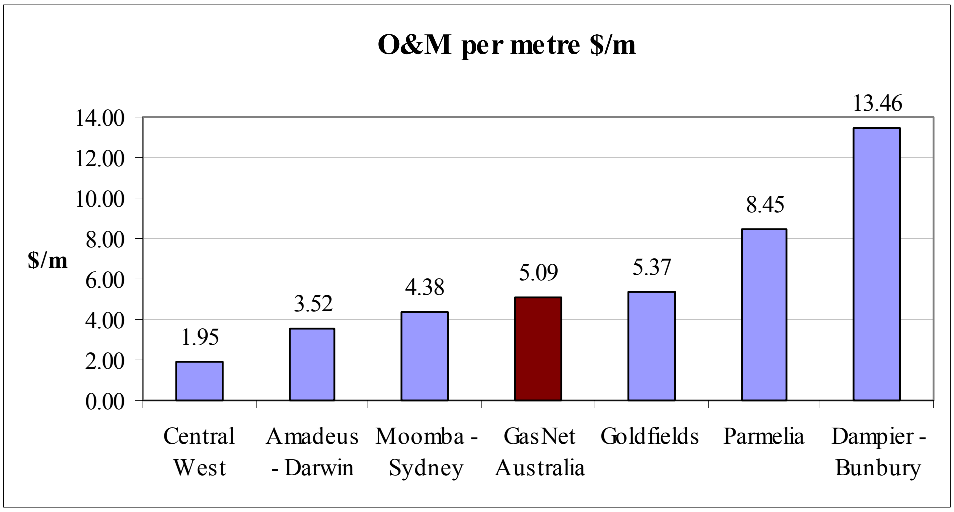
Figure 6-2: Operating Cost/Capital Investment



O&M costs per metre of pipeline

One of the simplest measures of O&M efficiency is cost per metre of pipeline. Figure 6-3 below shows that, on this measure, GasNet sits in the mid range of the scale. One of the reasons that GasNet has higher costs is that it operates a higher number of compressor stations (ie five) each with multiple compressors installed, and therefore incurs higher compressor maintenance costs (which is a major component of O&M costs). In addition, GasNet has a higher percentage of its pipelines located in urban and intensive farming areas where the cost of owning and maintaining pipelines is considerably higher than in less developed areas.

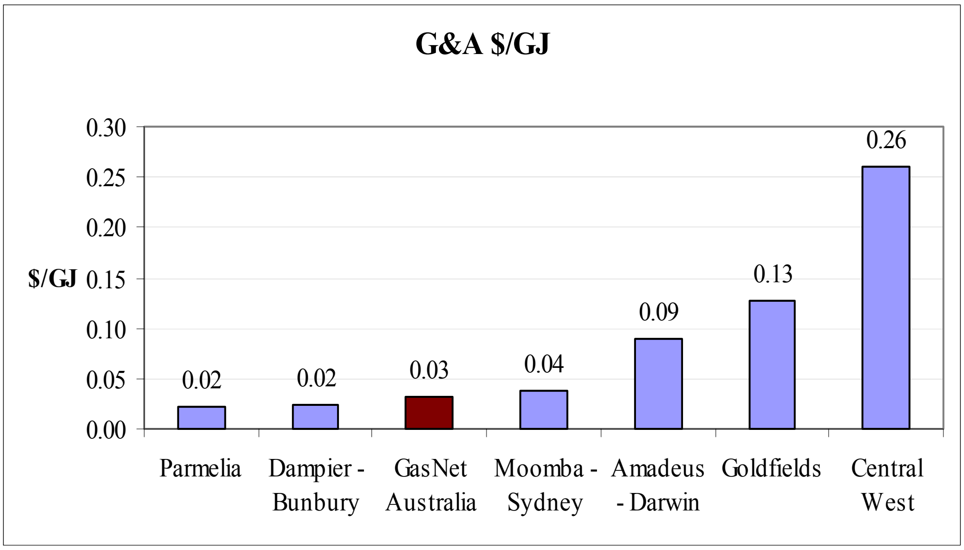
Figure 6-3: O&M costs per metre of pipeline



G&A costs per GJ of gas delivered

G&A expenses are unlikely to be related to the distance the gas travels. A more appropriate measure is gas volumes delivered. Figure 6-4 below illustrates that, on this measure, GasNet performs very well in comparison to other Australian pipeline companies.

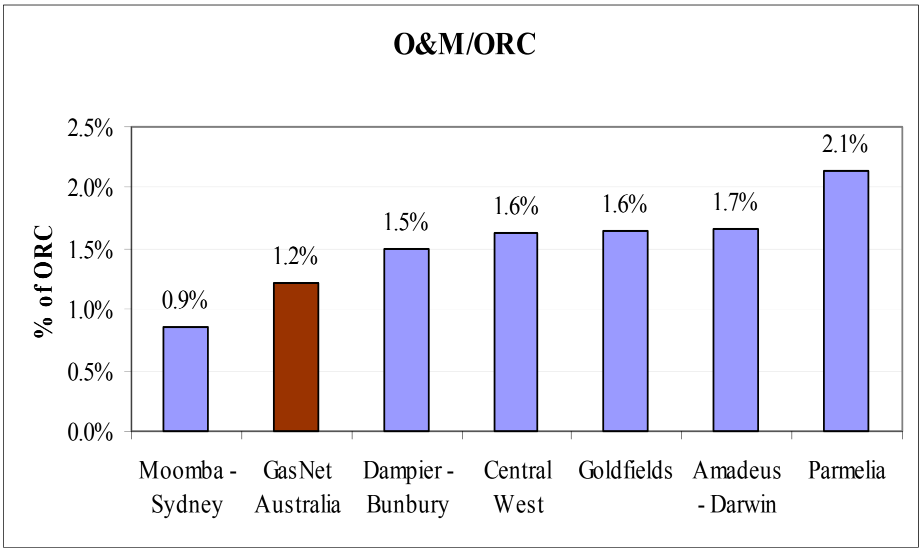
Figure 6-4: G&A costs per GJ delivered



O&M costs as a percentage of capital investment

The overall investment in an asset is often taken as representative of the workload required to operate and maintain the asset. Maintenance costs are related to the length of the pipeline and the number and complexity of compressor stations and hence to the capital invested in the assets.

Figure 6-5: O&M costs as a percentage of capital investment



The Moomba-Sydney pipeline performs somewhat better than GasNet and the other companies represented in the study. This may be related to the lower level of compression on the Moomba-Sydney pipeline in comparison to the GasNet system and the comparatively open, less developed country on the pipeline route. In addition, the pipelines differ significantly in the amount of linepack available, which bears strongly on the required standards of maintenance and response capability. The Moomba-Sydney pipeline has three days of linepack available, whereas GasNet has only four hours of linepack, which imposes an extremely short response time on GasNet in the event of an incident.

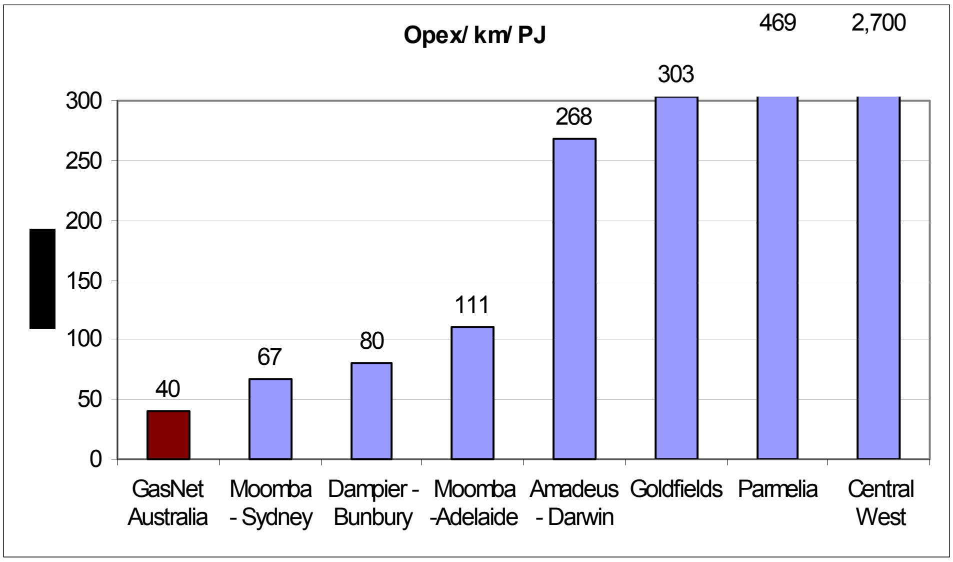
Compressor costs as a percentage of capital investment

The Commission has previously cited AGA studies which suggests that compressor maintenance costs would be typically between 3% and 6% of the capital investment in the compressors.[12] GasNet has calculated its compressor maintenance costs to be between 3.5% and 4.0% of capital investment. This puts GasNet at the lower end of the range indicated in the AGA report.

Operating costs/TJ/km

Another measure which is used to assess performance is operating costs/km/PJ. As indicated in the table below, GasNet performs well in relation to other Australian pipeline companies on this measure.

Figure 6.5A: Operating costs/km/PJ



6.2 Benchmarking report

GasNet commissioned a detailed Benchmarking Report from international consultants Cap Gemini. The study is based on GasNet's actual operating results for the year 2000 and also includes historical 1999 and projected year 2001 results. The sample consists of 24 companies from Australia, Canada, USA and South America. The study compares GasNet's results against four specific "peer group" companies, as well against the results of all 24 participating companies.

[12] See ACCC, *MSP Gas Access Arrangement* (Draft, 2000), p 89.

The following activities have been selected from the Benchmarking Report as most representative of the cost efficiency of GasNet:

(a) G&A expenses per million cubic meters delivered;

(b) pipeline maintenance expenses; and

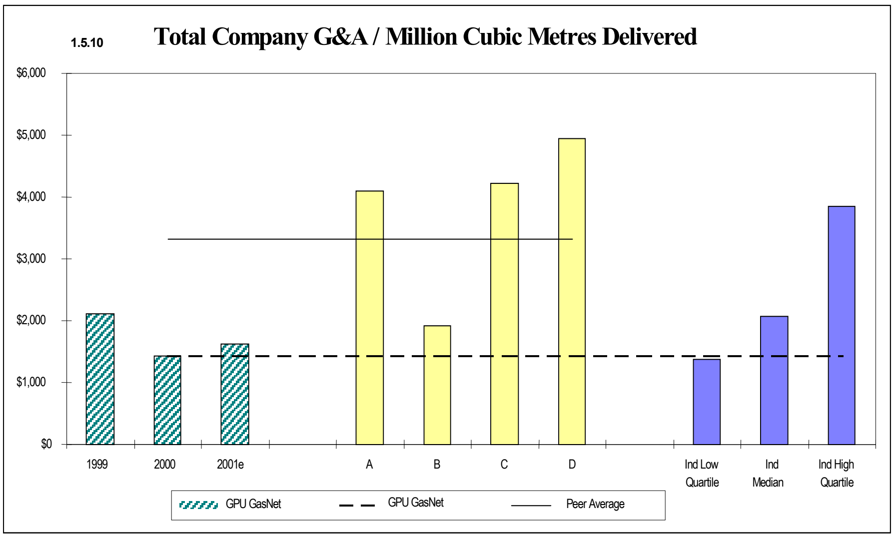
(c) compressor maintenance expenses.

These costs were defined specifically to enable intercompany comparisons and are not defined in the same way as the overall activity costs referred to above.

G&A expenses

The Benchmarking Report concluded that GasNet's overall G&A expenses per million cubic metres delivered were 55% lower than the average of the peer group. GasNet's unit costs fell very close to the lowest or best quartile of all participating companies. Figure 6-6 compares GasNet's total G&A costs per million cubic metres of gas delivered to the other companies in the sample.

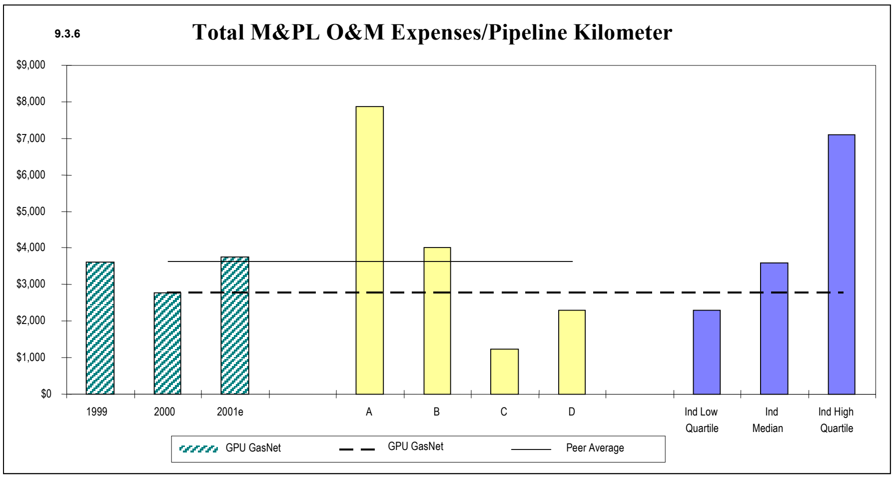
Figure 6-6: General & Administration Expense per Million Cubic Metres Delivered



Pipeline maintenance expenses per pipeline kilometre

The Benchmarking Report analysed pipeline maintenance expenses on the basis of the length of the pipeline system. The Benchmarking Report indicates that this is lower than the peer group average and the all company median. Figure 6-7 compares GasNet's pipeline maintenance expenses per kilometre with those of the other companies in the sample.

Figure 6-7: Measurement and Pipeline Expenses per Kilometre of Pipeline



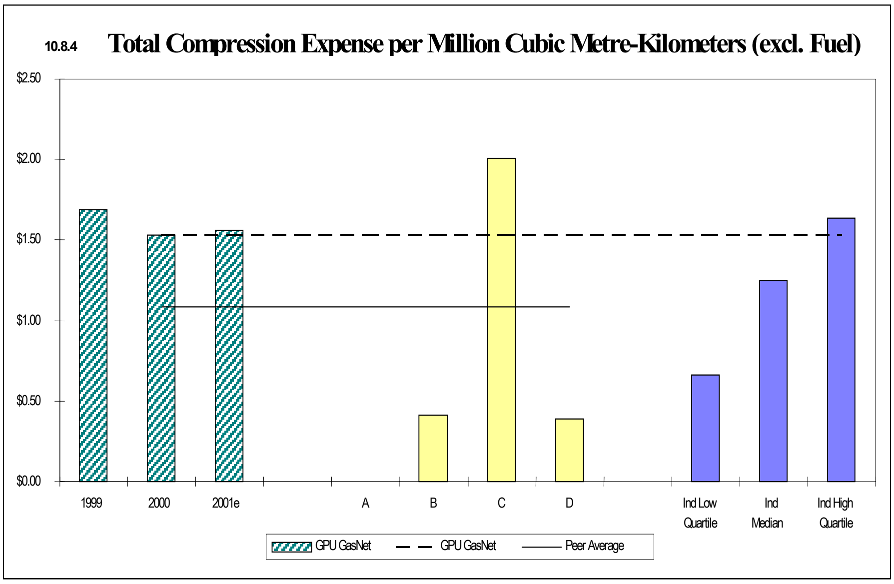
Compressor Maintenance Expenses

The primary normalising factor used in the Benchmarking Report to analyse compressor related costs was volume-distance (million cubic metre-kilometres). Compression expenses were examined without a fuel component.

The Benchmarking Report found GasNet's compression costs to be marginally higher than the median cost for the industry sample.

However, the Benchmarking Report notes that GasNet has a very low compressor utilisation factor, reflecting its seasonal demand patterns. Intermittent stop-start operation leads to higher costs compared to other companies. The Benchmarking Report also notes that some of the companies in the study operate long haul systems with very high unit horsepower and high utilisation rates. This tends to put GasNet at a competitive disadvantage when its costs are compared to the all company group. Figure 6-8 compares GasNet's compressor maintenance expenses per million cubic metre-kilometre with those of the other companies in the sample.

Figure 6-8: Compression Expense per Million Cubic Metres - Kilometres - excluding Fuel



7 Interpretation

7.1 Glossary

Access Arrangement means the draft Access Arrangement lodged by GasNet with the Commission on or about 31 March 2002.

Access Arrangement Period has the meaning given in the Code.

AA Information means the Access Arrangement Information (as defined in the Code) lodged by GasNet with the Commission on or about 31 March 2002.

Capital Base has the meaning given in the Code.

Code means the National Third Party Access Code for Natural Gas Pipeline Systems.

Commission means the Australian Competition and Consumer Commission.

Covered Pipeline has the meaning given in the Code.

Depreciation Schedule has the meaning given in the Code.

EGP means the Eastern Gas Pipeline operated by Duke Energy running from Longford, Victoria to Horsely Park, NSW.

Final Decision means the final decision on the TPA and VENCorp Access Arrangements issued by the Commission on 6 October 1998.

First Access Arrangement Period means in relation to the Former PTS, the period commencing on 15 March 1999 and ending on 31 December 2002 and in relation to the WTS, the period commencing on 1 January 1999 and ending on 31 December 2002.

Fixed Principles has the meaning given in the Code.

Former PTS means the transmission system the subject of the PTS Access Arrangement.

GasNet means, subject to section 1.3.4 of this submission, GasNet Australia (Operations) Pty Ltd ABN 65 083 009 278 (formerly GPU GasNet Pty Ltd).

GHD means the engineering consulting firm, Gutteridge, Haskins & Davey.

GNS means the GasNet System, being the Gas Transmission System, as defined in the Service Envelope Agreement.

Interconnect Assets means the Interconnect Pipeline, the Springhurst Compressor and the Interconnect Valves.

Interconnect Pipeline means the pipeline constructed by GasNet from Barnawartha in Victoria to Culcairn in New South Wales.

Interconnect Valves means the valves associated with the Interconnect Pipeline, comprising three remotely operated Barnawartha, Wandong and Ballan and an automated valve at Wollert.

KPI means key performance indicator.

Market Carriage has the same meaning given in the Code.

New Facilities Investment has the meaning given in the Code.

Non Capital Costs has the meaning given in the Code.

ODRC means optimised depreciated replacement cost.

ORC means optimised replacement cost.

Pipeline has the meaning given in the Code.

Prospective Users has the meaning given in the Code.

PTS Access Arrangement means the Access Arrangement by GasNet entitled "Access Arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System, which was first approved by the Commission for the period 15 March 1999 to 31 December 2002.

Rate of Return has the meaning given in the Code.

Reference Tariff has the meaning given in the Code.

Second Access Arrangement Period means the Access Arrangement Period for GasNet commencing on 1 January 2003.

Service Envelope Agreement means the agreement of that name entered into between VENCorp, GasNet (NSW) and GasNet dated 30 November 1998.

Services has the meaning given in the Code.

Service Provider has the meaning given in the Code.

Springhurst Compressor means the gas compressor located at Springhurst in Victoria, comprising a centrifugal compressor unit and powered by a Solar Turbines Centaur gas turbine.

SWP means the pipelines in Southwest Victoria comprising the South West Link (from Lara near Geelong to Iona near Port Campbell), the Western System Link (from Iona to North Paaratte, both near Port Campbell) and associated facilities.

Total Revenue has the meaning given in the Code.

TPA means Transmission Pipelines Australia Pty Ltd (ACN 079 089 268).

User has the meaning given in the Code.

VENCorp means Victorian Energy Networks Corporation.

VENCorp APR means the Annual Gas Planning Review 2002 to 2006, Victorian Energy Networks Corporation, November 2001.

WACC means weighted average cost of capital.

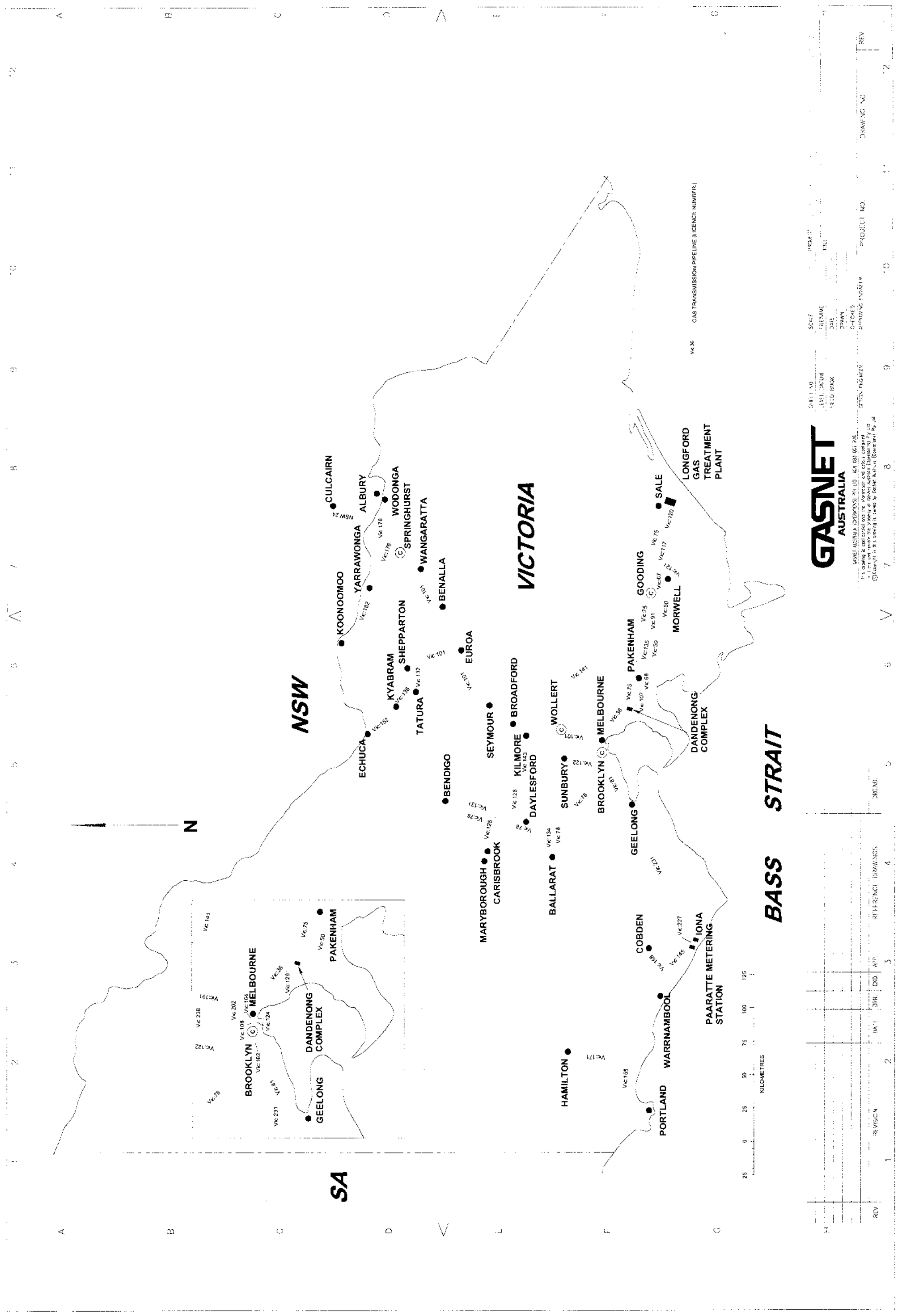
WTS means the Western Transmission System as defined in the WTS Access Arrangement.

WTS Access Arrangement means the Access Arrangement by GasNet for the WTS which was approved by the Commission for the period 1 January 1999 to 31 December 2002.

WUGS means the Western Underground Gas Storage located at Iona.

GasNet Australia Access Arrangement Information

Schedule 1 - Description of GNS



Description of Pipelines

Pipeline Licence	Location/Route	Length (km)	Pipe Diameter (mm)	MAOP (kPa)
	Longford to Dandenong and Wollert System			
Vic:68	Healesville-Koo-Wee-Rup Rd	1.2	80	2760
Vic:91	Anderson St, Warragul	4.8	100	2760
Vic:107	Pound Rd to Tuckers Rd	2.0	100	2760
Vic:50	Supply to Jeeralang	0.4	300	2760
Vic:50	Morwell to Dandenong	126.8	450	2760
Vic:75	Longford to Dandenong	174.2	750	6890
Vic:117	Rosedale to Tyers	34.3	750	7070
Vic:120	Longford to Rosedale	30.5	750	7070
Vic:135	Bunyip to Pakenham	18.7	750	7070
Vic:141	Pakenham to Wollert	93.1	750	6890
Vic:121	Tyers to Morwell	15.7	500	7070
Vic:67	Maryvale	5.4	150	6890
	Wollert to Wodonga/Echuca/ Bendigo System			
Vic:101	Keon Park to Wollert	14.1	600	2760
Vic:202	Keon Park East - Keon Park West	0.6	450	2760
Vic:101	Wollert to Wodonga	269.4	300	7400
Vic:101	Euroa to Shepparton	34.5	200	7400
Vic:132	Shepparton to Tatura	16.2	200	7390
Vic:136	Tatura to Kyabram	21.3	200	7390
Vic:152	Kyabram to Echuca	30.7	150	7390
Vic:143	Wandong to Kyneton	59.5	300	7390
Vic:128	Mt Franklin to Kyneton	24.5	300	7390
Vic:131	Mt Franklin to Bendigo	50.8	300	7390
Vic:78	Ballan to Bendigo	90.8	150	7390
Vic:125	Guildford to Maryborough	31.4	150	7390
Vic:238	Somerton Pipeline	3.4	250	2760
Vic:176	Chiltern Valley to Rutherglen	14.7	200	7400
Vic:182	Rutherglen to Koonoomoo	88.8	200	7400
Vic:178	Barnawartha to Murray River	5.5	450	10200
NSW:24	Murray River to Culcairn	57.0	450	10200
	Brooklyn to Ballarat System			
Vic:78	Brooklyn to Ballan	66.6	200	7390
Vic:78	Ballan to Ballarat	22.7	150	7390
Vic:134	Ballan to Ballarat	22.8	300	7390
Vic:122	Derrimut to Sunbury	24.0	150	7390

Pipeline Licence	Location/Route	Length (km)	Pipe Diameter (mm)	MAOP (kPa)
	Brooklyn to Geelong System			
Vic:81	Brooklyn to Corio	50.7	350	7390
Vic:162	Laverton to BHP	1.6	150	2760
	Dandenong to West Melbourne / Brooklyn System			
Vic:36	Dandenong to West Melbourne	36.2	750	2760
Vic:108	South Melbourne to Brooklyn	12.8	750	2760
Vic:129	Princess Hwy to Henty St	0.2	500	2760
Vic:129	Dandenong to Princess Hwy	5.0	750	2760
Vic:36	Princess Hwy to Regent St	0.8	200	2760
Vic:164	Supply to Bay St To Unichema	0.4	150	2760
Vic:124	Supply to Newport Power Station	1	450	2760
	Western Network			
Vic:145	Paaratte to Allansford	33.3	150	7400
Vic:155	Allansford to Portland	100.4	150	9890
Vic:168	Curdievale to Cobden	27.7	150	9890
Vic:171	Codrington to Hamilton	54.6	150	9890
	South West Pipeline			
Vic:227	Iona to Paaratte	7.8	150	7400
Vic:231	Iona to Lara	143.9	500	10200