APT Petroleum Pipelines Limited
ACN 009 737 393

ACCESS ARRANGEMENT INFORMATION FOR ROMA BRISBANE PIPELINE

Lodged with the ACCC

Under the National Third Party Access Code for Natural Gas Pipeline Systems

31 January 2006

Australian Pipeline Trust

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1 Introduction

1.1 Purpose of Access Arrangement Information

This Access Arrangement Information (AAI) is lodged by APT Petroleum Pipelines Limited ACN 009 737 393 (APTPPL). APTPPL is a wholly owned subsidiary of the Australian Pipeline Trust ARSN 091 678 778.

APTPPL is the owner of the Roma to Brisbane Pipeline (RBP).

This AAI has been prepared and lodged pursuant to Section 2 of the National Gas Code in support of the proposed Access Arrangement submitted by APTPPL on 31 January 2006. Attachment 1 shows the information categories required by Attachment A of the Code and indicates where this information is contained within this document.

A map of the RBP is set out in Attachment 6 of the Access Arrangement.

Projections in this AAI have been prepared to meet the requirements of the Code and are based on a number of assumptions. APTPPL does not make any representation or warranty as to the accuracy of the assumptions.

The following points apply throughout the AAI:

- Terms defined in the Access Arrangement and the National Gas Code have the same meaning in this AAI;

- Totals shown in tables in this AAI may not equal the sum of the elements of the tables due to rounding;

- Years shown in tables refer to financial years;

- Financial values shown in tables are real values in July 2006 $ (based on forecast CPI) unless otherwise indicated; and

- References to the ACCC should be read as referring to the relevant regulator. APTPPL understands that the roles and functions of the ACCC will be transferred to the Australian Energy Regulator during 2006 but legislation to effect the transfer of functions has not been enacted.

1.2 Background to the Roma Brisbane Pipeline (RBP)

The RBP was developed in the mid 1960s and commissioned in 1969 to transport gas from Wallumbilla (near Roma) to industrial gas users in Brisbane. Since that time, the capacity of the RBP has been expanded through compression and looping to the current nominal licensed capacity of 180 TJ/day. In addition a Lateral pipeline connecting the RBP to gas sources in the Peat / Scotia region was commissioned in 2001. The expansions of RBP capacity and the construction of the Lateral pipeline occurred in response to market growth, and were underpinned by contracts negotiated with third parties such as producers, power stations, gas utilities and major industrial customers.

The RBP currently receives gas from numerous receipt points and delivers gas to numerous delivery points. Additional receipt and delivery points have been added from time to time.

An Access Arrangement was established for the RBP in 2002, but due to the derogations applying under the Queensland legislation, the provisions of the Code dealing with establishment of Reference Tariffs, including the establishment of an initial Capital Base, did not apply to that Access Arrangement. Accordingly for the purpose of establishing financial parameters used in deriving Reference Tariffs this Access Arrangement is regarded as the initial Access Arrangement.

1.3 Key Dates

The RBP has had numerous changes of ownership and changes of ownership structure. Key dates in the history of the ownership, ownership structure and expansion of the RBP are shown below in Table 1.

Table 1: RBP Key Dates

Date (Calendar year)	**Event**
1965	Incorporated as Associated Pipelines Limited.
1969	Pipeline construction completed. Associated Pipelines Limited sells bundled gas and pipeline services. Associated Pipelines Limited has related ownership with upstream gas fields.
1982	Dalby Compressor installed. Kogan Compressor installed.
1983	Oakey Compressor installed.
1984	Condamine Compressor installed.
1985	Yuleba Compressor installed.
1986	Gatton Compressor installed.
1987	Joint Venture established. 85% interest held by Associated Pipelines Limited. 15% interest sold to I.O.L. Petroleum Limited.
1988	Associated Pipelines Limited name changed to CSR Petroleum Pipelines Limited. Acquisition of CSR Petroleum Pipelines Limited by The Australian Gas Light Company, as part of a larger acquisition of CSR's oil and gas production and transportation operations. This included the acquisition of gas production interests in Qld. CSR Petroleum Pipelines Limited name changed to AGL Petroleum Pipelines Limited.
1988	Looping 1 completed.
1989	Looping 2 completed.
1993	Upstream gas production interests sold by AGL.

1997	IOL Petroleum Limited change of name to Interstate Pipelines Pty Limited.
1998	Looping 3 completed.
2000	AGL divestment of its pipelines group includes AGL Petroleum Pipelines Limited through float of Australian Pipeline Trust. AGL Petroleum Pipelines Limited change of name to APT Petroleum Pipelines Limited (APTPPL).
2000	Looping 4 completed.
2001	Peat Lateral completed.
2001	Acquisition of Interstate Pipeline’s 15% interest by APTPPL.
2001	Looping 5 completed.
2002	Looping 6 completed.
2003	Scotia extension to Peat Lateral completed.

2 Access & Pricing Principles

2.1 System Definition

The RBP consists of:

(a) the mainline pipeline from Wallumbilla (near Roma) to Brisbane and associated facilities **(Mainline);**

(b) the lateral pipeline from Peat / Scotia to Arubial, on the RBP mainline, and associated facilities **(Lateral).**

The Mainline was included in Schedule A to the Code and is therefore a Covered Pipeline. APTPPL voluntarily Covered the Lateral from 1 January 2006.

The Access Arrangement applies to the Mainline and Lateral as configured at 31 January 2006. The Reference Tariff has been derived on the basis of the capacity existing at that date (**Existing Capacity**).

2.2 Determination of Total Revenue

The Total Revenue is determined through the NPV methodology as permitted under Section 8.4 of the Code.

In determining the Total Revenue APTPPL has adopted a real approach as permitted under Section 8.5A of the Code. The Total Revenue is based on:

(a) a real rate of return being applied to the real Capital Base; and

(b) depreciation, capital costs and non-capital costs are expressed as real values.

While APTPPL is currently investigating expansion of RBP, and anticipates undertaking expansion of the RBP during the Access Arrangement Period, the timing, cost and nature of any expansion is currently uncertain. Therefore no amount in respect of capacity expansion is included in the derivation of Total Revenue.

The model used to derive Total Revenue is an annual model.

2.3 Reference Service and Cost Allocation

There is one Reference Service offered on the RBP - a firm, forward haul service for receipt, transport and delivery of gas in the direction from Wallumbilla to Brisbane. Consistent with existing contracts and customer enquiries, APTPPL considers this to be the Service likely to be sought by a significant portion of the market[1].

All of the Total Revenue is allocated to the Reference Service over the Access Arrangement Period.

[1] As required by Code 3.3 (a)

No allowance has been made for revenue that may accrue from the sale of Negotiated Services that may be entered into following any capacity expansion of the RBP, as no capital in respect of such expansion has been included in the calculation of the Total Revenue.

In deriving capacity and throughput charges no allowance has been made for revenue that may accrue from any other charge as these are not considered material. Other charges include, but are not limited to, overrun charges, balancing charges, daily variance charges and charges payable in respect of receipt points and delivery points.

The Reference Service has a two-part tariff, being a Capacity Charge (expressed as dollars per GJ of MDQ per Day) and the Throughput Charge (expressed as dollars per GJ).

The allocation of revenue between Capacity Charge and Throughput Charge is 95% to Capacity Charge and 5% to Throughput Charge. This reflects the fact that almost all of the costs of providing Services are fixed and do not vary with the quantity of gas transported.

The Reference Tariff is a single tariff for receipt, transport and delivery of gas anywhere within the RBP system. This broadly reflects the tariff structure for existing contracts.

2.4 Price Path and Incentive Mechanism

As permitted by the Code in 8.3 (b), APTPPL has adopted a Price Path Approach, under which Reference Tariffs are determined for the whole Access Arrangement Period to follow a path forecast to deliver the Total Revenue.

As Reference Tariffs were determined on the basis of assumed movements in CPI over the Access Arrangement Period, the Access Arrangement provides for Reference Tariffs to be adjusted to reflect actual movements in the CPI[2].

The prospect of retaining improved returns for the Access Arrangement Period provides an incentive for APTPPL to minimise the cost of providing Services consistent with Sections 8.44 to 8.46 of the Code. This includes non-capital costs and stay in business capital.

[2] APTPPL has adopted a real approach to the derivation of Total Revenue as allowed by 8.5A of the Code.

3 Revenue Requirement

This section sets out the parameters used in determining Total Revenue for the Access Arrangement Period.

3.1 Initial Capital Base

APTPPL has established the value of the initial Capital Base consistent with the decision of the Australian Competition Tribunal in the MSP case[3], through the application of the "NPV DORC" methodology.

The Optimised Replacement Cost (ORC) has been calculated as at October 2005. The ORC value is $456.1 million. For the calculation of NPV DORC the ORC value is adjusted by:

- including equity raising costs at a level of 3.83%[4] of equity value, as noted by the Allen Consulting Group
- reducing linepack costs[5].

The NPV DORC has been calculated at October 2005, and gives a value of $342.6 million. This amount is adopted as the initial Capital Base[6].

The ORC and initial Capital Base values are shown in Table 2.

The assets that form the initial Capital Base have then been allocated into the asset classes shown in Table 2. This allocation is based on the relativity of each asset class in the optimised replacement pipeline.

Table 2: RBP initial Capital Base ($m October 2005)

Asset class	ORC Value	% of ORC	NPV DORC	Initial Capital Base
Transmission Pipelines (incl line pack)	368.2	80.7 %		276.5
Compressor Stations	54.0	11.8 %		40.6
Receipt and Delivery Stations	13.7	3.0 %		10.3
Land	13.3	2.9 %		10.0
Buildings	2.1	0.5 %		1.6
Communications	4.8	1.1 %		3.6
Total	**456.1**	**100%**	**342.6**	**342.6**
Add Equity Raising Costs	6.6			
Subtract Line Pack	0.5			
Adjusted Total	**462.2**			

3 Application by East Australian Pipeline Limited [2004] ACompT 8 (8 July 2004) and [2005] ACompT 1 (18 March 2005)

4 The Allen Consulting Group (2004) "Debt and Equity Raising Transaction Costs: Report to the Australian Competition and Consumer Commission" p61

5 The ORC pipeline included $681,000 in linepack. This has been reduced to $180,000 to reflect the assumption that users would provide some of the linepack consistent with current practice.

6 The Initial Capital Base is at October 2005. This figure has been inflated by forecast CPI and adjusted for depreciation to obtain a July 2006 value for the Capital Base.

3.2 Factors considered in Initial Capital Base

3.2.1 Range of values under Code Section 8.10

Section 8.10 of the Code outlines factors that should be considered in establishing the initial Capital Base.

Section 8.11 of the Code provides that the ICB normally should not fall outside the range of DAC and DORC values. The initial Capital Base proposed by APTPPL is consistent with Section 8.11 of the Code as it reflects the DORC value calculated under 8.10 (b).

3.2.2 Depreciated Actual Cost

Section 8.10 (a) of the Code provides consideration should be given to:

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

This value is commonly known as Depreciated Actual Cost (DAC).

The section requires that

- from the actual *capital* cost of the pipeline
- the amount of *depreciation* charged (or thought to be charged) to users
- is *subtracted.*

Firstly, the actual *capital* cost is to be identified. This is not simply the *construction* cost, but the *capital* cost of the assets. It is therefore necessary to reflect in the calculation all of the capital costs of the assets including engineering, development, legal, capital raising costs, easement acquisition etc.

Secondly, it is necessary to identify the depreciation charged or thought to be charged to users. The reference to depreciation *charged* indicates that economic depreciation, not accounting depreciation, is required to calculate the DAC.

Lastly, the section refers to *subtraction* – not *recognition* or *adjustment.* Where there has been recovery of depreciation, that amount is to be subtracted from the capital cost. Where there has been no recovery, or an under-recovery of depreciation, there is no adjustment to the actual capital cost and the DAC will be the actual capital cost.

3.2.2.1 The Actual Cost of the RBP

Due to the age of the RBP and its various changes of ownership and ownership structure, accurate information on the actual capital cost of the Covered Pipeline is not available.

In estimating the actual capital cost, APTPPL has used the values recorded in the APTPPL asset register. These values do not in themselves represent the actual capital cost of the RBP, but they provide a reasonable, albeit probably understated, starting point[7].

There are no assets recorded in the asset register for dates prior to 1971 (with the exception of land at $2,643), notwithstanding the pipeline was commissioned in 1969. However, the fixed pipe and plant at cost on the balance sheet at 30 June 1969 was $8.9 million. This value has been incorporated into the calculation of the actual capital cost.

The asset register also includes several asset revaluations totalling $34.9 million. As it is not clear whether these values are relevant to the actual capital cost of the Covered Pipeline, APTPPL has not incorporated these amounts into the calculation of the actual cost.

In order to calculate the actual costs in real terms, each item in the asset register has been indexed from the date of construction or acquisition to 30 June 2005. This amount is shown in Table 3.

Table 3: Actual Cost of the RBP

Cost Measure	**Value in Asset Register (nominal $)**	**CPI Indexed value at June 30 2005**
Actual Cost from Asset Register incl Revaluations	$181,875,459	$227,713,936
Minus Revaluation	$34,878,801	$52,352,295
Plus cost of Original Pipeline	$8,852,166	$77,966,209
Actual Cost of Pipeline	$155,848,824	$253,327,850

The indexed value for 1 July 2006 is $260.6 million based on forecast CPI of 2.88%.

3.2.2.2 Depreciation Charged to Users

Economic depreciation is calculated as the residual (positive or negative) derived from subtracting both operating costs and a return on capital from revenue. Accordingly, the calculation of economic depreciation for the RBP requires knowledge of the following, over the whole of the life of the RBP:

- amounts charged to Users for use of the Covered Pipeline (separate from revenues from other assets and activities)
- capital and non-capital costs of the Covered Pipeline (separate from the costs of other assets)
- the basis on which capital was invested, particularly the returns required in respect of various capital investments.

[7] The asset register shows asset costs, some capital costs such as working capital costs and development costs may not be reflected in the asset register.

It is not possible to make any meaningful calculation of the amount of economic depreciation recovered from Users over the life of the RBP. In particular there is insufficient financial information available to accurately identify these matters.

3.2.2.3 Subtraction of depreciation

With any pipeline, the minimum value for DAC will be zero (where depreciation recovered from users is equal to or greater than the actual capital cost). The maximum value will be the actual capital cost (where there has been no depreciation recovered from users).

In the case of the RBP, the value for DAC is therefore within the range of zero to $253.3 million (or an equivalent escalated value).

3.2.3 Depreciated Optimised Replacement Cost (DORC)

Section 8.10 (b) of the Code provides consideration should be given to

> *the value that would result from applying the depreciated optimised replacement cost methodology.*

The calculation of a DORC requires the calculation of an ORC. The ORC process involves determining a cost for an optimised replacement of the RBP - this optimisation has regard to current capacity and contractual obligations, future growth forecasts, developments in construction techniques and technology, and changes in factors influencing the pipeline route.

APTPPL instructed Venton & Associates Pty Ltd to prepare an estimate of the ORC for the RBP, having regard to forecast load growth for the next 20 years[8]. Venton & Associates report that the ORC of the RBP at October 2005 is $456,145,000. This value was adjusted for linepack differences and equity raising costs[9]. The adjusted ORC was then used to calculate the NPV DORC value and the initial Capital Base value at October 2005 of $342.6 million.

The concept of DORC (depreciated optimised replacement cost) used is based on the net present value of cost differences (i.e. NPV DORC)[10]. NPV DORC is described in the following terms by the Commission[11]:

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[8] APTPPL is aware that an alternative view of ORC is the optimised replacement cost of the existing assets, with no allowance for forecast growth.

[9] Adjustment as per The Allen Consulting Group (2004) "Debt and Equity Raising Transaction Costs: Report to the Australian Competition and Consumer Commission" p61

[10] In some previous regulatory decisions a methodology known as straight line DORC has been applied. Given the degree to which understanding and analysis of DORC has developed since the introduction of the Code, and the decision of the Tribunal in the MSP Case, APTPPL does not place any weight on the straight line DORC methodology or value. APTPPL has however calculated a value using this methodology. This value is approximately $315 million.

[11] At paragraph A.1.3 of the ACCC's Amended Submission to the Tribunal filed on 20 December 2004 in *Re Application of East Australian Pipeline Limited* (No 8 of 2003) (*Application of EAPL*).

NPV cost-based DORC represents the difference between:

(i) the present value of the costs of providing a stream of services using the efficient optimised replacement infrastructure and subsequent replacements (with replacements made at the end of the optimised replacement asset's life), and

(ii) the present value of the costs of providing a stream of services into perpetuity using the existing infrastructure and subsequent replacements (with replacements made at the end of the existing infrastructure's life).

NPV DORC is calculated from the viewpoint of a hypothetical new entrant (HNE). According to this approach, DORC is the amount the HNE would pay an incumbent to acquire the existing asset given that an HNE has the option to build a new asset of comparable service capability (and earn the same revenues) (HNE DORC).

Regulatory precedent and literature supports calculation of NPV DORC from the hypothetical new entrant viewpoint. APTPPL takes the view that the HNE DORC approach is appropriate.

As outlined above the optimised replacement pipeline has been optimised for future growth forecasts. For consistency in calculating the present value of the costs of the existing infrastructure APTPPL has taken account of capital expansion costs in the calculation to ensure the existing pipeline is able to satisfy the future growth forecasts assumed in designing the optimised replacement pipeline.

The discount rate used in the NPV calculations in the NPV DORC approach is the WACC in section 3.5 of this AAI.

The NPV DORC value calculated is $342.6 million.

3.2.4 Other Well Recognised Valuation Methodologies

Section 8.10 (c) of the Code requires consideration should be given to "other well recognised valuation methodologies". APTPPL is not aware of any other well-recognised valuation methodologies that that would be appropriate and are currently given substantial weight by Regulators under the Code.

3.2.5 Expectations Under the Previous Regulatory Regime

Section 8.10(g) of the Code requires consideration should be given to:

> *the reasonable expectations of persons under the regulatory regime that applied to the Pipeline prior to the commencement of the Code.*

The prior regulatory regime was established in 1995 under Part 8 of the Petroleum Act 1923 (Qld). This regime provided for regulatory oversight of the terms of third party access to the RBP, including the submission of Access Principles for approval by the Queensland Government. Where the approved Access Principles did not specify a tariff, the contract with Users had to be approved by the Minister.

The matters to be considered by the Minister when approving Access Principles or contracts included:

- The objectives of the Act, namely to facilitate competitive markets in the petroleum industry for the benefit of the public and the industry, to promote efficiency in the petroleum industry and to provide for access to facilities on fair commercial terms
- The legitimate business interests of the facility owner
- The legitimate business interests of existing facility users and possible future facility users
- Fair and efficient market conduct with respect to tariff arrangements and access conditions for the facility
- Operational and technical requirements for the facility's safe and reliable operation
- Amounts invested in constructing and operating the facility
- The reliability of the service offered
- The cost to the facility owner of providing access but not the costs associated with losses from increased competition in upstream and downstream markets
- Contractual obligations of the facility owners and facility users
- Efficiency and economy in the facility's construction, operation and use
- Any additional investment in the facility by someone other than the facility owner

Under that regime, it was reasonable for APTPPL to expect to be able to continue to charge tariffs established under the Access Principles or contracts.

3.2.6 Past basis for tariffs and Economic Depreciation

Section 8.10(f) of the Code provides consideration should be given to:

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

Prior to the introduction of the regulatory regime established in 1995 under Part 8 of the Petroleum Act 1923, tariffs were set through commercial negotiation. Following the amendments to Part 8 of the Petroleum Act, tariffs were set in accordance with the Access Principles or by negotiation, subject to the requirement for Ministerial approval. There is insufficient information available to determine the basis on which tariffs were negotiated over the life of the pipeline.

As discussed in section 3.2.2 above, accurate identification of economic returns to the service provider over the life of the Covered Pipeline is problematic.

3.2.7 Tariff Structure of Potential Competing Pipelines

Section 8.10(i) of the Code provides consideration should be given to:

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

APTPPL is not aware of any proposal for a pipeline that may by-pass the Covered Pipeline.

The ORC reflects the cost of a pipeline to bypass the RBP. As the NPV DORC methodology recognises the shorter remaining life of the existing pipeline, the proposed ICB will result in tariffs which are no higher than tariffs which the developer of a by-pass pipeline would have to charge to recover the costs of the new pipeline over its life.

Because the ORC reflects the most efficient route and design of a replacement (or by-pass) pipeline, an initial Capital Base and tariffs reflecting that ORC do not lead to a result which encourages inefficient bypass.

3.2.8 Price Paid for Assets Recently Purchased by the Service Provider

Section 8.10(j) of the Code requires consideration to be given to the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase. The meaning of this section has been considered several times by regulators, and the consensus seems to be that unless a transaction is part of a fully arm's length competitive process, little if any weight will be given to such transactions[12].

While APTPPL acquired 15% of the RBP in 2001, the transaction occurred in the following context:

- the vendor was exiting Australia and this was one of their few remaining assets
- APTPPL had pre-emptive rights relating to the purchase
- There was no public or competitive process undertaken by the vendor.

Additionally, the transaction occurred approximately five years ago, and since this purchase the pipeline's nominal capacity has been expanded from 101 TJ / day to 180 TJ / day and the Peat Lateral has been commissioned. In light of

- the apparent regulatory consensus regarding treatment of asset purchase prices
- the circumstances of the purchase
- the substantial change in the character of the pipeline

this purchase price has not been given any weight.

3.3 Estimated Capital Expenditure

The Total Revenue includes minor capital expenditure and stay in business capital. It does not include any capital expenditure to fund any expansion of the Pipeline as Reference Tariffs are being established for the Existing Capacity.

[12] For example: ACCC, *Final Decision on Moomba Sydney Pipeline Access Arrangement*, October 2003, pp.48-50; Australian Competition Tribunal in *MSP Case (*2004) at paragraph 34; Economic Regulation Authority, *Final Decision on Goldfields Gas Transmission Pipeline Access Arrangement*, May 2005, paragraphs 167-170

Minor capital expenditure and stay in business capital covers replacement of miscellaneous capital equipment and enhancements of peripheral and utility systems and equipment. Capital expenditure forecast during the Access Arrangement Period includes instrumentation (metering, telemetry remote terminal units etc), pipeline hardware (valves, regulators and fittings), minor site capital improvements and specialised major spares.

Forecast capital expenditure costs on the RBP are made up of the following items:

- Pigging program in 2007 and 2010. Regulations require regular pipeline inspections, for example AS 2885.3 requires periodic inspections with the frequency dependent on the condition of the pipeline and the Queensland Petroleum and Gas (Production and Safety) Act requires pigging of established pipelines to be carried out at least every 10 years.
- Pipeline excavation and inspection program from 2007 to 2011 is required as part of the pigging program.
- Coating defect assessment in 2009. Prudent periodic inspection is required to verify pipeline integrity for AS 2885.3 compliance.
- Compressor overhauls from 2007 to 2011. These are undertaken by APTPPL to ensure the safe and reliable operation of the pipeline and are related to the manufacturers standard. These overhauls are capitalised.
- Minor capital and stay in business capital - this includes such items as hazardous area rectification, fire suppression systems, noise suppression systems, pipeline slabbing, cathodic protection upgrade, SCADA upgrade, compressor exhaust system upgrade, purchase of additional specialised tools and equipment and replacement of vehicles and specialised tools and equipment. This capital spending is required to continue the safe, reliable and efficient operation of the pipeline.
- Access Arrangement costs - these costs are capitalised over the length of the Access Arrangement and.
- RBP proportion of a new APT IT system.

To recognise the need for additional minor capital work to be undertaken as the pipeline ages the above costs, with the exception of Access Arrangement costs and IT upgrade costs, escalate by 1% on a year to year basis.

Table 4 below shows the amounts for these items.

Table 4: RBP Capital Expenditure (July 2006 $M)

Capital Expenditure	2006-7	2007-8	2008-9	2009-10	2010-11
Pigging	1.00	-	-	0.66	-
Coating defect assessment	-	-	0.17	-	-
Pipeline excavation and inspection	0.19	0.19	0.19	0.19	0.20
Compressor overhauls	0.31	0.32	0.32	0.32	0.32
Minor and stay in business capital	2.04	1.59	0.94	0.81	0.71
Access Arrangement costs	0.50	-	-	-	-
IT system upgrade	0.10	-	-	-	-
Total	**4.14**	**2.09**	**1.62**	**1.98**	**1.23**

3.4 Depreciation of Capital

APTPPL has adopted the NPV methodology to determine the Total Revenue.

Reference Tariffs are set to result in a Reference Tariff in 2011 which approximates the forecast average tariff at that time under current contracts. Based on forecast volumes and costs, a price path escalating a 100% of CPI from July 2006 was developed to reach the 2011 tariff outcome. The Residual Value of the Capital Base at the end of the Access Arrangement Period is determined by adjusting the Capital Base at 1 July 2006 to reflect forecast revenues, costs, capital expenditure and economic depreciation over the Access Arrangement Period.

The asset lives and remaining lives as at 1 July 2006 are shown in Table 5. The economic life and the remaining economic life of the transmission pipeline are based on weighted averages of the original pipe and the looping.

Table 5 Asset Economic Lives

Asset Class	Economic Life (years)	Remaining Economic Life At 1 July 2006
Transmission Pipeline	74	57
Compressor Stations:	35	12
Receipt and Delivery Stations	74	57
Land	Not applicable	Not applicable
Buildings	74	57
Communications	15	9

The opening value for the assets comprising the initial Capital Base (July 2006) and their value at the end of the Access Arrangement Period are shown in Table 6[13].

The initial Capital Base value at 1 October 2005 has been adjusted for inflation and asset age.

Table 6 RBP Capital Base Roll-Forward (July 2006 $M)

Asset Class	Opening Value as at 1 July 2006	Residual Value as at 30 June 2011
Transmission Pipelines Receipt and Delivery Stations Buildings	289.6	302.7
Compressor Stations:	40.7	42.6
Land	10.0	10.5
Communications	3.6	3.8
Total	343.9	359.5

Changes in the value of the Capital Base over the Access Arrangement Period are shown in Table 7.

[13] The value for transmission pipelines includes $180,000 of line pack.

Table 7 Opening and Residual Values (July 2006 $M)

	2006-7	2007-8	2008-9	2009-10	2010-11
Opening Asset Value	343.9	349.1	352.1	354.6	357.6
Capital Expenditure	4.1	2.1	1.6	2.0	1.2
Depreciation	-1.0	-0.9	-0.9	-1.0	-0.7
Closing Value	349.1	352.1	354.6	357.6	359.5

3.5 Cost of Capital

Sections 8.30 and 8.31 of the Code require the cost of capital used in determining the Reference Tariff to:

> *provide a return commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service.*

The methodology used by APTPPL is a weighted average cost of capital (WACC) approach based on the capital asset pricing model (CAPM).

The cost of capital used is a pre-tax real weighted average of the returns applicable to debt and equity.

The return on equity has been determined using the CAPM. The return on debt has been determined as the sum of the risk free rate of return, an estimate of the corporate debt margin, and an estimate of the costs of raising debt.

3.5.1 Ranges approach

In identifying the cost of capital APTPPL has applied the "ranges approach".

This approach was described as follows by the Economic Regulation Authority (ERA) in the Goldfields Gas Transmission (GGT) Final Decision[14];

> *The Authority accepts that its task is to consider whether the Rate of Return used for the derivation of Reference Tariffs in the revised Access Arrangement falls within the range of rates commensurate with the prevailing market conditions and the relevant risk. This Rate of Return will comply with the Code if the value used is within the range of values that different minds acting reasonably might attribute to the Rate of Return, applying the methodology of the CAPM that was chosen by GGT. In undertaking this task, the Authority has given consideration to the range of values within which the Rate of Return might be supported by reasonable minds as being commensurate with prevailing conditions in capital markets.*

In applying the ranges approach to the cost of capital APTPPL has undertaken the following steps.

[14] Economic Regulation Authority 2005 Final Decision on the Proposed Access Arrangement for the Goldfields Gas Pipeline p63 paragraph 282

- Used cost of equity and cost of debt approaches as outlined above
- Used recent market parameters for inputs where these parameters are readily observable
- Set ranges for inputs where these inputs are either not readily observable or are subject to interpretation.
- Calculated cost of equity and cost of debt using recent observable market parameters and the ranges for those parameters that are not observable to give a range of outcomes.

3.5.2 Parameters

The cost of capital parameters are outlined below.

3.5.2.1 Variables - Readily Observable Parameters - No Ranges Used

Nominal risk free rate of return - 5.43%- This is the 20 working day average of Australian Government 10-year bonds[15] from 3 Nov to 30 Nov (ie 20 working days).

Real risk free rate of return - 2.48% - This is the 20 working day average of Australian Government indexed bonds[16] from 3 Nov to 30 Nov (ie 20 working days).

Expected inflation - 2.88% - Expected inflation is derived by applying the Fisher equation to the bond rates shown above. Note that this is the inflation used in all of the Access Arrangement modelling

Debt to equity ratio - This ratio is set at 40% equity and 60% debt. This is generally consistent with recent regulatory decisions.

Statutory corporate tax rate -This rate is 30%.

3.5.2.2 Variables - Subject to Interpretation - Ranges Used

Debt margin - 1.02% - 1.09% - The debt margin is the margin for a BBB corporate bond (ie RBP business only) over the nominal risk free rate. The use of a BBB credit rating was ordered by the Australian Competition Tribunal in the EAPL Decision[17].

Recent margins for BBB bonds are 1.02% to 1.09%. These are based on Bloomberg figures for synthetic BBB 10-year corporate debt for November 2005. Allen Consulting Group[18] notes that Bloomberg are significantly more accurate predictors of actual bond margins.

Debt Raising Costs - 0.125% - 0.25% - The GasNet Australian Competition Tribunal Decision 2003 allowed for 25 basis points per annum for debt raising costs above the debt margin. Other recent decisions[19] relating to gas infrastructure allow 12.5 basis points per annum for debt raising costs above debt margin.

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[15] 6.25% 15 April 2015 bond
[16] 4.00% 20 August 2015 indexed bond
[17] *Application by East Australian Pipeline Limited* [2004] ACompT 8 (19 May 2005)
[18] Allen Consulting Group, 2005, Cost of Capital For Queensland Gas Distribution p34
[19] For example see table 5.5 p 32 of Allen Consulting Group, 2005, Cost of Capital For Queensland Gas Distribution

Market risk premium - 5% - 6% - The range used for the market risk premium is 5% to 6%. This range is generally consistent with recent regulatory decisions, although APTPPL believes the upper limit of the range could be higher.

Betas - 0.8 - 1.2 - The beta measure used is the equity beta.

The equity beta range is 0.8 to 1.2, although APTPPL believes the upper limit of the range could be higher for some pipelines. This range is consistent with recent regulatory decisions for gas pipelines, in particular the ERA Decision on the Dampier Bunbury Pipeline[20].

APTPPL recognises that this range is broader than the equity beta range of 0.9 to 1.1 used by the Allen Consulting Group for Queensland gas distribution companies. In relation to this APTPPL notes that:

- Gas pipeline transmission, especially in Queensland, directly supplies power station and industrial loads. The size of these loads adds a degree of upside and downside risk to pipelines that may not be present for distribution companies.
- The ERA in the GGT decision calculates a range and then truncated the range to derive a reasonable range, whereas the Allen Consulting Group has explicitly not adopted this truncation approach[21]. It may be argued that the Allen Consulting Group has effectively truncated the range by truncating key variables.

Valuation of imputation credits (also known as gamma) -30% - 60%. The range used for gamma is 30% to 60%. This range is generally consistent with recent regulatory decisions.

3.5.2.3 Range for Parameters

The values are shown below.

Table 8 WACC parameters

CAPM Parameter	**High**	**Low**
Nominal Risk Free Rate	5.43%	5.43%
Real Risk Free Rate	2.48%	2.48%
Inflation Rate	2.88%	2.88%
Cost of Debt Margin over Risk Free Rate	1.09%	1.02%
Cost of raising debt	0.25%	0.13%
Nominal pre-tax cost of debt	6.77%	6.58%
Real pre-tax cost of debt	3.78%	3.59%
Market Risk Premium	6.00%	5.00%
Corporate Tax Rate	30.00%	30.00%
% of Franking Credits given value by shareholders	30.00%	60.00%

[20] Economic Regulation Authority, 2005, Draft Decision on the Proposed Access arrangement for the Dampier to Bunbury Natural Gas Pipeline p49 Table at paragraph 197.
[21] Allen Consulting Group 2005 Cost of Capital For Queensland Gas Distribution p16

LT Proportion of Equity Funding	40.00%	40.00%
LT Proportion of Debt Funding	60.00%	60.00%
Equity Beta	1.2	0.8

3.5.2.4 Range for WACC

The cost of capital calculated values are shown below. Table 9 below shows the shows the range of Rate of Return values derived from the parameters.

Table 9 WACC Ranges

Cost of Capital Measure	High	Low
Nominal Cost of Equity	12.63%	9.43%
Real Cost of Equity	9.48%	6.37%
Pre-Tax Nominal WACC	10.46%	8.23%
Pre-Tax Real WACC	7.37%	5.20%

The ERA also stated[22]:

> *… the range of values that different minds acting reasonably could attribute to the cost of equity and WACC is narrower than the ranges that the extremes of ranges in CAPM parameters would suggest.*

and[23]

> *… the Authority is of the view that the range of values that would comply with the Code should not include the values that lie within the lower 10 percent or upper 10 percent of the range that may be derived by the application of the extremes of values for each of the parameters of the CAPM.*

APTPPL has adopted this approach. The pre tax real WACC range of 7.37% - 5.20% is truncated, as per the ERA process outlined above. The range is 2.17% in all - taking 0.22% off the top and bottom of the range gives a revised range of 7.15% to 5.42%.

Within this range a pre tax real WACC of 6.90% has been used as the cost of capital parameter in determining Reference Tariffs.

APTPPL believes the cost of capital range and cost of capital parameter selected are consistent with the Reference Tariff principles, and that the Cost of Capital parameter selected falls within the range of rates commensurate with the prevailing market conditions and the relevant risk.

APTPPL notes that the cost of capital parameter selected would also lie within the reasonable range, as adjusted for observable variables, identified by Allen Consulting Group in relation to Queensland distribution assets[24].

[22] Economic Regulation Authority 2005 Final Decision on the Proposed Access Arrangement for the Goldfields Gas Pipeline p65 paragraph 288
[23] Ibid p66 paragraph 293

3.6 Non-Capital Costs

The Total Revenue includes non-capital costs incurred in the delivery of the Reference Service. All non-capital costs have been allocated to the Reference Service.

Forecasts of non-capital costs are provided in Table 10.

These forecasts have been based on direct costs to APTPPL of operating the RBP including services being provided by Agility Management Pty Limited (Agility) on a contract basis, and an allocation of APT Corporate overheads.

The efficiency of non-capital costs for the RBP is discussed in Section 6 of this AAI.

3.6.1 APT Corporate Costs

APT corporate costs include items such as salaries, directors fees, rent, office costs, IT costs, communications costs, costs associated with stock exchange listing (eg share registry fees, annual report preparation) and other costs incurred in the operation of the APT Group.

Corporate costs have been allocated as follows:

- **Labour costs** - allocations are determined for each staff member as follows:
  - Staff who perform a significant amount of work directly related to the RBP (eg staff in Queensland) are allocated at a percentage reflecting the proportion of their work involving the RBP.
  - Staff whose work covers the whole company and whose costs are otherwise not allocated are allocated at approximately 14% to the RBP.
  - Staff whose work does not relate to the RBP (eg staff in Western Australia) are allocated at 0%.

These costs are escalated at 6% to reflect forecast salary and personnel increase.

- **Non-labour costs** - there is an allocation process between direct and non-direct costs related to the RBP.
  - Direct costs are 100% attributed.
  - Queensland office costs are 75% attributable to the RBP. The APT Queensland office is responsible for the Roma Brisbane Pipeline and the Carpentaria Gas Pipeline. The work undertaken is predominantly driven by contract management and legal and commercial issues. This allocation is broadly consistent with the number of contracts on the RBP and the differing amounts of work undertaken in relation to the various pipelines.
  - The remaining costs are allocated at approximately 14% to the RBP.

These costs are escalated at CPI.

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[24] Allen Consulting Group 2005 Cost of Capital for Queensland Gas Distribution p68 identify a range of 5.53% to 6.95%. APTPPL believe that by adjusting this range for more recent observable bond rates the range is 5.6% to 7%.

3.6.2 Operations and Maintenance Cost

Agility provides operations and maintenance services for the RBP.

The forecast cost of services provided by Agility, and of spare parts, is $5.8 million in 2006. This escalates generally in line with CPI. The services include all asset management, operations and maintenance work required for the safe, efficient and compliant operation of the RBP, as configured at 31 January 2006. The amount paid to Agility Management includes the costs of direct operations, operations support, engineering support, pipeline maintenance and easement management. Key categories of this work are:

- Planned and corrective maintenance on pipework and compressors
- Planned and corrective easement patrol and easement management
- Planned and corrective cathodic protection
- Pipeline monitoring and control (ie control centre functions including telemetry)
- Asset maintenance planning and scheduling
- Asset performance testing and validation
- Accounting for day-to-day operations
- Regulatory compliance obligations relating to technical regulatory compliance and maintenance of asset records. This includes compliance with licences, AS 2885, environmental regulations etc.

3.6.3 Other Costs (Insurance, Licence Fees, Govt Charges etc)

Insurance, licence fees, rates and other government charges are $0.40 million.

Insurance is based on a quote for the stand-alone cost to insure the RBP. The other costs are based on actual costs.

These costs are escalated at CPI.

3.6.4 Additional Non-Capital Costs

3.6.4.1 Security

APTPPL has included an amount for additional operating expenditure as a result of increased security measures in response to the threat of terrorism. APTPPL is undertaking reviews of the security of key infrastructure with a view to improving the security of key installations. Additional expenditure is due to additional patrols, remote monitoring, programs to assess security risk and development of contingency capabilities.

The amount included in the forecast costs is $100,000 per annum. These costs are escalated at CPI. This amount is approximately 1% of non-capital costs.

The recent ESC decision on Victorian Electricity network prices made allowances for additional costs for infrastructure security[25].

[25] Essential Services Commission 2005 Electricity Distribution Price Review 2006-2010.Final Decision Volume 1: Statement and Purpose of Reasons p 309. Note that in this decision some distributors sought security opex

3.6.4.2 Self Insured Risk

APTPPL has included an allowance for the cost of self-insurance of low likelihood, high impact asymmetric risks. This allowance will enable it to cover the costs incurred as a result of a rare event that is not insured.

Instances of situations resulting in self-insured risk include computer crime, computer breakdown, crisis management, legal actions, extortion and death or disability of key personnel.

The forecast costs of self-insurance are $80,000 per annum. These costs are escalated at CPI.

The 2003 GasNet Australian Competition Tribunal Decision allowed for asymmetric risks of $172,000 per annum. The amount of $80,000 forecast by APTPPL is consistent with the GasNet figure as a percentage of non-capital expenditure.

Gas used in operations as either compressor fuel or unaccounted for gas is included in non-capital costs[26].

Forecast non-capital costs are shown in Table 10 below.

Table 10 Total Non Capital Costs (July 2006 $M)

Non-Capital Expenditure	**2006-7**	**2007-8**	**2008-9**	**2009-10**	**2010-11**
Wages and salaries	0.83	0.86	0.88	0.91	0.94
APT Other Corporate Costs	2.08	2.08	2.07	2.06	2.06
Operations, Maintenance, Insurance, Licence Fees, Security and Self Insured Risk	6.40	6.35	6.29	6.24	6.19
Total	9.31	9.28	9.24	9.21	9.18

and others sought security capex. On average across all distributors the amount sought for capex and opex was approximately0.6% of total capex and opex but individual networks recovered security opex and capex up to approximately 1.5% of total opex and capex.

[26] Note that Users supply compressor fuel and unaccounted for gas is negligible.

3.7 Total Revenues

The Total Revenue for the Access Arrangement Period is set out in Table 11.

Table 11 Total Forecast revenue (July 2006 $M)

	2006-7	2007-8	2008-9	2009-10	2010-11
Return on Capital	23.7	24.1	24.3	24.5	24.7
Non-Capital Costs	9.3	9.3	9.2	9.2	9.2
Depreciation	-1.0	-0.9	-0.9	-1.0	-0.7
Total revenue	32.0	32.5	32.6	32.7	33.1

3.8 Allocation of Total Revenue

Reference Tariffs for the Reference Service are determined to recover the Total Revenue over the Access Arrangement Period. The Tariffs are based on the volume forecast set out in Section 4.1 of this AAI.

Following calculation of the Total Revenue the revenue is allocated to Reference Tariffs. All Total Revenue is allocated to the Reference Tariff. There is no allocation to other services.

3.8.1 Price Path

A pre GST tariff for the year commencing 1 July 2006 as follows:

(a) Capacity Charge $0.4243 / GJ of MDQ capacity / Day; and

(b) Throughput Charge $0.0283 / GJ throughput.

With the price path thereafter to be linked to a CPI – X adjustment as shown in the Access Arrangement where X equals 0% for the term of this Access Arrangement.

Inflation is estimated at 2.88% per annum, as outlined in Section 3.5.2 of this AAI. Under the Access Arrangement, Reference Tariffs are adjusted annually to reflect actual inflation

The forecast Reference Tariffs for each year of the Access Arrangement Period are as shown in table 12.

Table 12 Reference Tariff (July 2006 $)

Reference Tariff	2006-7	2007-8	2008-9	2009-10	2010-11
Capacity Charge	0.4243	0.4243	0.4243	0.4243	0.4243
Commodity Charge	0.0283	0.0283	0.0283	0.0283	0.0283

4 Volumes and Tariff Schedule

4.1 Forecast Volumes

The following table set out APTPPL's forecast of RBP throughput and peak day capacity. This forecast is for Services provided by the RBP's Existing Capacity. No expansion capital is included in the Access Arrangement Period and therefore the forecast volumes used to derive Reference Tariffs reflect only the forecast volumes for the Existing Capacity.

The capacity used in deriving the Reference Tariff is the forecast volumes below in Table 13. The forecast volumes are able to exceed the nominal capacity of 180 TJ as load is withdrawn from the Mainline upstream of capacity constraints and slightly downstream of a major Receipt Point. The determination of spare capacity available for each Delivery Point is dynamic. As quantities are contracted for a particular Delivery Point, the dynamics of the total system change. The effect on overall system capacity of a delivery to a point closer to the Receipt Point is less than that of a delivery to the extremities of a system.

Table 13 Forecast RBP Volumes for the Pipeline as Configured 31 January 2006

Volumes	**2005-6**	**2006-7**	**2007-8**	**2008-9**	**2009-10**	**2010-11**
MDQ TJ/ Day	177.5	196.2	199.1	199.8	200.5	202.9
RBP Forecast Throughput (PJ/pa)	51.1	56.5	57.3	57.5	57.7	58.4

5 System Information

5.1 System Capability and maximum delivery capability

The capacity of a pipeline system is determined by a set of operating and technical parameters. These include, but are not limited to, the following:

- pipeline size
- pipeline inlet and outlet pressures
- pipeline inlet and outlet locations
- gas temperature
- gas quality;
- ambient conditions (temperatures)
- receipt and delivery flow profiles (hourly/daily/weekly)
- the distribution of the demand on the pipeline system
- compressor operation.

As gas travels along a pipeline its pressure gradually declines, mainly due to friction. To increase delivery capacity, compressors are used to boost the pressure as required. The RBP currently has six mainline compressor stations.

The current nominal capacity of the total RBP system is approximately 180 TJ/d based on a number of major assumptions including a minimum receipt pressures at receipt points, delivery point weekly load profiles, no use of capacity for storage, compressor operation etc.

5.2 Map of pipeline system

A map of the RBP is attached as Attachment 2 of this AAI.

5.3 Average Daily and Peak demand and Annual volume

The following Table 14 contains average and peak day throughput for major Delivery Points on the RBP.

Table 14 Average and Peak Day Throughput (GJ/D) (Actual 2004-5)

Major Delivery Point	Average daily throughput	Peak day throughput	Minimum Delivery Pressure (kPag)
Condamine (not operational at Dec 2005)	Confidential		4,000
Dalby			1,500
Oakey PS			3,000
Oakey			1,000
Toowoomba			1,000
Sandy Creek			400
Brightview			500
Riverview			1,500

Redbank			1,000
Ellengrove			1,500
Swanbank			4,500
Runcorn			1,500
Mt Gravatt			1,500
Tingalpa			1,500
Murarrie			1,500
Doboy			1,500
Gibson Island			1,500
Total	131,520	210,397*	
Total System Wide Peak Day (receipts)		178,197	
Total System Wide Peak Day (deliveries)		168,902	

* Note the peak day throughput is the peak throughput for each individual delivery point - not the throughput through each off take on the system peak day.

5.4 Physical dimensions - Pipe Sizes and Distances.

This section provides details relating to the technical specifications of the RBP. The applicable construction Codes were ASME B31.8 for Original Pipeline and AS2885 for looping and the Peat Lateral

Key RBP system characteristics and parameters include in Table 15.

Table 15: RBP System Characteristics and Parameters

Commissioning Dates and Lengths	
Original pipe	Commissioning date – March 1969 Mainline (Wallumbilla to Bellbird Park) – 397 km Metro Section (Bellbird Park to Gibson Island) - 42km.
Looping 1 Looping 2 Looping 3 Looping 4 Looping 5 Looping 6	July 1988 69.54 km Sept 1989 70.95 km February 1990 53.17km June 2000 61.72km December 2001 139.47km August 2002 11.00km
Peat Lateral	Commissioning date - 2001. Total length 121 km
Steel grade	
Original pipe	API 5L x46 / X42

Looping 1 Looping 2 Looping 3 Looping 4 Looping 5 Looping 6 Peat Lateral	API 5L X60 API 5L X60 API 5L X60 API 5L X60 API 5L X70 API 5L X60 API 5L X60
Pipeline Diameter	
Original Pipe Looping Peat Lateral	DN250mm (10”) Wallumbilla to Bellbird Park City Gate Station; DN300mm (12”) Bellbird Park City Gate Station to SEA B/V DN200 (8”) SEA B/V to Gibson Island DN400mm (16”) Looping DN250mm (10”)
Pipeline Wall Thickness	
Original pipe Looping 1 Looping 2 Looping 3 Looping 4 Looping 5 Looping 6 Peat Lateral	4.78mm, 5.15mm, 6.35mm. 6.4mm, 7.7mm 6.4mm, 7.7mm 6.6mm, 7.9mm, 9.5mm 6.6mm, 7.9mm, 8.4mm 5.7mm, 6.8mm, 8.1mm 9.5mm 4.78, 5.7mm
Maximum Allowed Operating Pressure	
Original pipe Looping Peat Lateral	DN250mm (10” Mainline) Roma to Bellbird Park - 7,136 kPa; DN300mm (12”) Bellbird Park to SEA B/V - 4,200 kPa; DN200 (8” SEA B/V to Gibson Island)- 4,200 kPa; DN400mm (16” Mainline) Roma to Bellbird Park - currently 8,000 kPa, but designed to 9,600 kPa 10,200 kPa
Other Specifications	

Original Pipe and Looping External coating Valve coating Joint coating Concrete coating **Peat Lateral** External coating Above Ground facility Below ground Joint coating	 Polyken over ditch wrap and 1.2mm HDPE factory applied coating. 2000 microns Taubmans Intertuff UHB or other approved two part epoxy. Denso 543/ R23 over approved primer or Polyken 943 inner & 955 outer over Polyken 1027 primer. Heat shrink sleeves to Looping 1 and 2. Weighted coated pipe at watercourse crossings where necessary HDPE AS 1518 minimum thickness of 1.2mm All above ground pipework and steelwork is painted with a high quality corrosion resistant paint system. Below ground Dulux Luxaflex Polyken 9454
Compressor station sites Original pipe Looping	 10” Mainline (Original pipe) Yuleba, Kogan and Oakey 16” Mainline (Looping) Condamine, Dalby and Gatton.
Installed compression	Kogan 1981 Dalby 1981 Oakey 1982 Condamine 1984 Yuleba 1985 Gatton 1986
Active inlet custody transfer meter stations	Wallumbilla (4 meter runs) and Interconnect with Peat Lateral (PPL 42)

	On PPL42 (Peat Lateral) - Scotia and Woodroyd
Active sales outlet custody transfer meter stations	Condamine, Dalby, Oakey, Toowoomba, Sandy Creek, Brightview, Riverview, Redbank, Ellengrove, Swanbank, Runcorn, Mt Gravatt, Tingalpa, Murarrie, Doboy and Gibson Island Note that gas from the Peat Lateral enters the RBP licence 2 Mainline at Arubial Pressure Reduction Station
Main Line Valves	DN250 (10"): MP20, MP40.4, MP63, MP86.05, MP106.27, MP117.4, MP128, MP142.24, MP189, MP200.97, MP217.15, MP236.97m MP248.06. DN400 (16"): MP14, MP54, MP100.5, MP152.8, MP178, MP189, MP217.5, MP236.97, MP245.6. Peat Lateral Scotia (SW0) Woodroyd (WA0), L-Tree Creek W-A 51.96, Arubial (WA 110.7)
Scraper (pig) launch and/or receive facilities	DN250 (10"): MP0, MP33.4, MP67.4, MP100.4, MP133, MP167.2, MP207. DN400 (16"): MP0, MP33.4, MP67.4, MP100.5, MP133, MP167.2 Peat Lateral Scotia (SW0) Woodroyd (WA0), Arubial (WA 110.6)
Maintenance bases	Wallumbilla, Condamine, Dalby, & Gatton
Pipeline control	Mt Gravatt
Right of Way identification Marker tape Depth of cover Concrete slabs	Signage generally at 250m interval or line of sight. Marker tape in designated areas

Depth of cover	(built up areas, road crossings etc) Depth of Cover: 750 – 1,000 mm in roads and most locations 1,200 mm for directional drills 1200 mm under roads, rail or watercourse crossings & possible future T1 areas. Looping 1 to 4 & 6 1200mm or greater. Looping 5: 750mm in private land 750mm or greater - West of Dalby 900MM or greater – East of Dalby. Peat Lateral Rural Areas (R1) 750mm, Rural Areas (R2) 900mm, Roadways 1200mm. Rail crossings 2000 mm, Watercourse/road crossing 1800mm Concrete slabbing is provided at locations for extra protection including: • Road crossings • At locations where depth of cover or wall thickness is insufficient.

5.5 System Load Profile by Month

The monthly load profile is based on load profiles from 2004-5. The load profile is presented in terms of percentages. See Table 16 below.

Table 16 System Load profile by month

Month	**% of total Annual Load**
January	8.6 %
February	8.5 %
March	8.8 %
April	8.6 %
May	8.0 %
June	7.8 %
July	8.1 %
August	6.9 %
September	8.7 %
October	8.5 %
November	9.1 %
December	8.4 %
Total	**100 %**

5.6 Numbers of Users on the RBP as at 31 January 2006.

Table 17 below shows the number of Users on the RBP at 31 January 2006.

Table 17 Users on the RBP

Type of service	**Number of Users**
Firm	5
Interruptible Only	1
All	**6**

6 Efficient Costs and Performance Measures for Pipelines

6.1 Efficient Costs

Section 8.1 (a) of the Code provides that a Service Provider's Reference Tariff and Reference Tariff Policy should be designed to provide the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient cost of delivering the Reference Service. Section 8.37 of the Code defines efficient costs as those incurred by a prudent Service provider acting efficiently, in accordance with accepted and good industry practice to achieve the lowest sustainable cost of delivering the Reference Service.

6.2 Issues Relating to Performance Measures and Benchmarking of Transmission Pipelines

6.2.1 Differences in pipeline characteristics

It is important to recognise the limitations of benchmarking. The numerous variables that can and do affect costs means that benchmarking can only provide a broad indication of whether a particular pipeline costs lie within the range of possible efficient costs.

There is a difficulty in "normalising" pipelines to yield meaningful benchmarking comparisons due to differences in the following pipeline characteristics:

- pipeline distance
- pipeline diameter
- pipeline remoteness
- pipeline age and condition
- operational characteristics such as the number of compressors, receipt points and delivery points
- markets served
- natural and man-made environment through which the pipeline passes.

Any comparisons involving the RBP should take account of the following factors:

- The RBP is a looped pipeline with two different sizes of pipe running parallel to each other, sometimes in the same easement and sometimes in separate easements. No other major pipelines in Australia have this degree of looping.
- Some operating cost items such as vegetation management and easement surveys are significantly driven by both the length of the pipeline route and the nature of the environment through which the pipeline runs. The pipeline route of the RBP is approximately 440km for the Mainline and 121km for the Lateral. Approximately 10% of the Mainline passes through the built up area of Brisbane, resulting in an increased level of easement management and maintenance, compared to other pipelines crossing open or non-urban country.
- Some operating cost items such as internal inspections (“pigging”) and cathodic protection are driven by the actual length of the pipe. In the case of the RBP, the relevant length for such costs is approximately 965km (rather than the 560km of the pipeline route).

- The number of compressors on the pipeline affects the operation and maintenance costs. The RBP is relatively heavily compressed, with six compressors installed.
- The size and age of compressors affects the relative costs of operating and maintaining the compressors.
- As pipelines age the costs of operation and maintenance generally increase. The original Mainline section of the RBP is relatively old compared with many other Australian pipelines.

6.2.2 Meaningful basis of benchmarks

Benchmarks must have a sound basis to be meaningful. In order to derive a meaningful set of benchmarks it is necessary to have both an understanding of the pipeline industry and its cost drivers.

From APT's experience in constructing and operating pipelines, indicative "rules of thumb" have been developed that are used to estimate total operating costs in investigating new pipeline opportunities. While applying these generalised rules does not provide for the specific circumstances of the pipeline it provides an indication of what operating costs can be expected in broad terms.

These generalised rules are set out in Table 18 below.

Table 18 Indicative Total Pipeline Expense (excluding compressor costs) as a Percentage of Asset Replacement Cost

Asset	Large	Average	Small
Pipeline	1.5%	2%	2.5%

Consistent with these benchmarks the Commission has previously stated that the pipeline operating cost should be in a range of 2% of replacement cost for uncompressed pipelines to 5% of replacement cost for fully compressed pipelines[27]. The Commission suggested ORC as a measure of the value of the capital assets employed.

While there are a number of broad factors that affect costs the primary cost driver is the length of the pipeline. Other secondary cost drivers are compressor stations and receipt and delivery stations. A pipeline's diameter has a minor secondary impact on operating costs.

Length, compressors, receipt stations, delivery stations and diameter are all reflected in a replacement value, such as ORC.

Pipeline throughput and capacity do not have a significant impact on operating costs. Measures that use these are generally invalid.

[27] ACCC (2001) Final Decision Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System Date: 12 September 2001 p57 and p 203

The best indicators use either pipeline length or a replacement value, such as ORC. The non-capital cost benchmarks used in this Access Arrangement are:

- $ cost per km of route length and $ cost per km of pipeline length
- $ cost per $ ORC

The costs benchmarked below reference the RBP forecast non-capital cost figure used in this Access Arrangement[28].

6.3 Comparator Pipelines

The following pipelines were used as comparators given the availability of regulatory decisions on the efficient non-capital costs of those pipelines.

- Gasnet / Vencorp
- Moomba-Adelaide pipeline
- Dampier-Bunbury pipeline
- Goldfields Gas Transmission
- Moomba Sydney pipeline

6.4 Key findings

Generally RBP non-capital cost levels are in line with industry standard.

6.4.1 Non-Capital cost per km of pipeline route and pipeline in situ

For most pipelines the length of the pipeline route and the length of the pipes in situ are identical. However for looped pipelines they are not identical.

Using both measures generates a range. These measures recognise that the RPB pipeline loops share some common costs (eg easement patrols) but that some costs are specific to the pipe in situ.

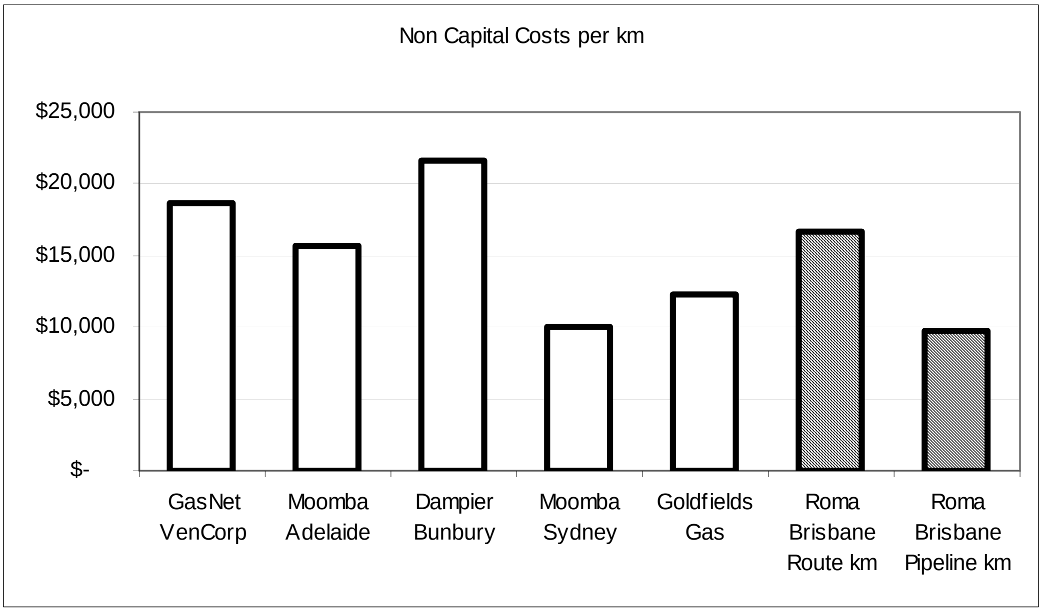
For non-capital cost per kilometre of pipeline route the RBP performs moderately relative to other pipelines due to the non-capital cost measure reflecting items that are genuinely required to be incurred twice, give the pipeline’s actual configuration.

For example, cathodic protection cost must be carried for each loop. Also, while the loops share an easement for much of the distance between Roma and Brisbane, it is not the case that the two loops share an easement for the entire distance.

For non-capital cost per kilometre of pipeline in situ the RBP compares favourably relative to other pipelines. This is expected as costs that are only incurred once are spread over a longer pipeline length.

[28] To allow meaningful comparisons the performance measures in this Section 6 of the Access Arrangement Information reflect non-capital costs as reflected in various regulatory decisions, these costs may not be completely comparable due to differing treatments of corporate costs.

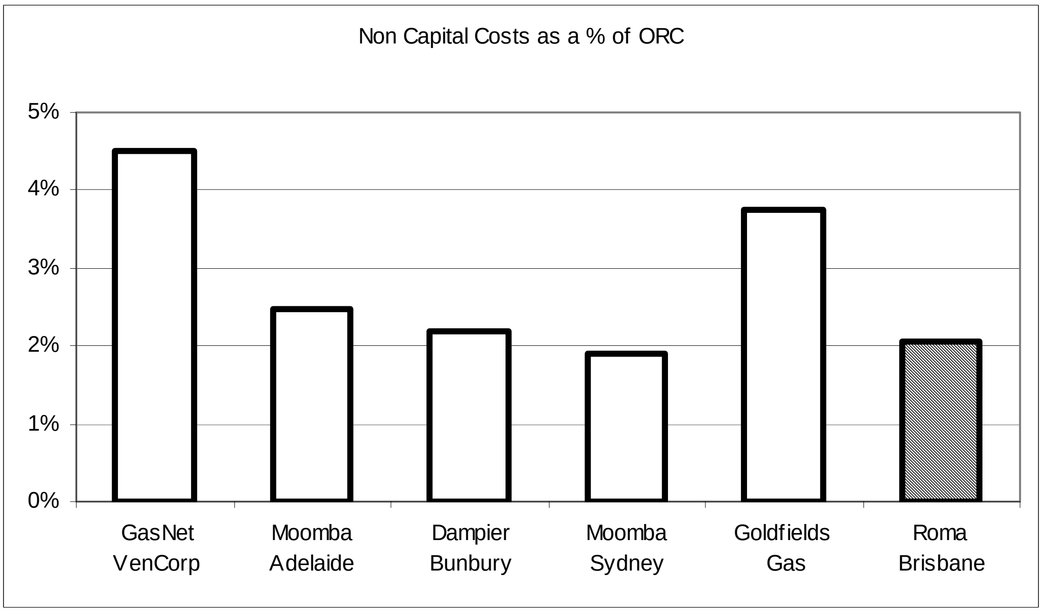
Chart 1



6.4.2 Non capital cost as a percentage of Optimised Replacement Cost

The RBP non-capital cost is approximately 2% of ORC. This is lower than the level previously accepted by the Commission as efficient for a fully compressed pipeline.

Chart 2



ATTACHMENT 1

CATEGORIES OF INFORMATION TO BE DISCLOSED AS PART OF THE ACCESS ARRANGEMENT INFORMATION

Category in Access Code	Reference in Access Arrangement Information
Category 1: Information regarding Access & Pricing Principles.	
Tariff determination methodology.	**2.2, 2.4**
Cost Allocation approach	**2.3**
Incentive structure.	**2.4**
Category 2: Information regarding Capital Costs	
Asset values for each pricing zone, service or category of asset.	**3.1**
Information as to asset valuation methodologies – historical cost or asset valuation.	**3.2**
Assumptions on life of asset for depreciation.	**3.4**
Depreciation.	**3.4**
Accumulated depreciation.	**3.4**
Committed capital works and capital investment.	**3.3**
Description of nature and justification for planned capital investment.	**3.3**
Rates of return – on equity and on debt.	**3.5**
Capital Structure – debt/equity split assumed.	**3.5**
Equity returns assumed – variables used in derivation.	**3.5**
Debt costs assumed – variables used in derivation.	**3.5**
Category 3: Information regarding Operations and Maintenance Costs	
Fixed versus variable costs.	**3.6**
Cost allocation between zones, services or categories of asset & between regulated and unregulated.	**2.3, 3.6**
Wages & Salaries – by pricing zone, service or asset category.	**3.6**
Cost of services by other including rental equipment.	**3.6**
Gas used in operations – unaccounted for gas to be separated from compressor fuel.	**3.6**
Materials and supply	**3.6**
Property Taxes	**3.6**

Category in Access Code	Reference in Access Arrangement Information
Category 4: Information on Overheads & Marketing Costs	
Total service provider costs at corporate level	**3.6**
Allocation of costs between regulated and unregulated segments.	**2.3, 3.6**
Allocation of costs between particular zones, services or categories of asset.	**2.3, 3.6**
Category 5: Information regarding System Capacity & Volume assumptions	
Description of system capabilities	**5**
Map of piping system – pipe sizes, distances and maximum delivery capability.	**ATTACHMENT 2**
Average daily and peak demand at "city gates" defined by volume and pressure.	**5.3**
Annual volume across each pricing zone, service or category of asset.	**4.1**
System load profile by month in each pricing zone, service or category of asset.	**5.5**
Total Number of customers in each pricing zone, service or category of asset.	**5.6**
Category 6: Information regarding Key Performance Indicators	
Industry KPIs used by the Service Provider to justify "reasonable incurred" costs.	**6.4**
Service provider's KPIs for each pricing zone, service or category of asset.	**6.4**

ATTACHMENT 2

MAP OF ROMA BRISBANE PIPELINE SYSTEM