Moomba Sydney Pipeline

Access Arrangement Information

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Australian
Pipeline Trust

East Australian Pipeline Limited
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1. INTRODUCTION

1.1 Background to the revised Access Arrangement Information

East Australian Pipeline Limited (**“EAPL”**) is the owner of the Pipeline referred to in the revised Access Arrangement submitted to the Australian Competition and Consumer Commission (**“Commission”**) on 30 April 2002 as the Moomba-Sydney Pipeline (**“MSP”**).

This revised Access Arrangement Information is submitted by EAPL to assist the Commission and interested parties in their review of the Access Arrangement for the MSP. While presentation of a revised Access Arrangement Information is not contemplated under the Code, the changes to the commercial and regulatory environment in which EAPL operates that have occurred since the original Access Arrangement and Access Arrangement Information was submitted in May 1999 are significant, and therefore make revision of the Access Arrangement Information necessary. These have included:

- Change in ownership of EAPL. In 1999 EAPL was owned 51% by AGL and 49% by Petronas and NovaCorp. On 13 June 2000 the Australian Pipeline Trust (**“APT” -** a listed managed investment scheme) was floated and acquired AGL’s pipeline assets, including its interest in EAPL, together with Petronas’ and NovaCorp’s interest in EAPL thereby giving APT 100% ownership of EAPL;
- Commencement of the operation of a competing pipeline, the Eastern Gas Pipeline (**“EGP”**) in September 2000;
- A revised Access Arrangement submitted to the Commission on 30 April 2002;
- Proposed changes to Balancing arrangements arising from practices of certain shippers on the MSP;
- Errors of law identified in the Commission’s Draft Decision (19 December 2000) as a consequence of the decision by the WA Supreme Court in respect of the Draft Decision on the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline - *Re Dr Ken* Michael *AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd. & anor [2002] WASCA 231* (**“the Epic Decision”**); and
- Revised forecasts of volumes, operating expenditure and capital expenditure arising out of announcements by AGL on 18 December 2002 about new long term supply arrangements. AGL’s position as the major shipper on the MSP means its changed supply arrangements have significant implications for future MSP volumes.

This Access Arrangement Information reflects the revised Access Arrangement submitted to the Commission on 30 April 2002 (see in particular Section 3 of the revised Access Arrangement). In addition, it reflects the change to the initial Capital Base (ICB) proposed by EAPL in its 5 November 2002 submission to the Commission on the impact of the Epic Decision on the Draft Decision. It also incorporates changes to forecast volumes, capital expenditure and operating expenditure submitted to the Commission on 12 May 2003. These will need to be reflected in changes to Reference Tariffs in the revised Access Arrangement.

The revised Access Arrangement adopts a Net Present Value (NPV) methodology (with residual) to the determination of Reference Tariffs.

Attachment 1 to this revised Access Arrangement Information shows the information categories listed in Attachment A of the Code and indicates where this information is contained within this document.

1.2 Provision for Possible Revocation of Coverage of the MSP

The revised Access Arrangement (April 2002) recognises that EAPL has applied for revocation of coverage of the MSP and that the Minister for Industry, Tourism and Resources may approve the application. EAPL has allowed for this possibility by providing different tables of Reference Tariffs under a range of possible revocations scenarios in the schedules of the revised Access Arrangement. These scenarios are:

- All pipelines are covered;
- Moomba Wilton Pipeline and Canberra Lateral are not covered: Wagga Lateral and Regional Laterals are covered;
- Moomba Wilton Pipeline is not covered: Wagga Lateral: Canberra Lateral and Regional Laterals are covered; and
- Canberra Lateral not covered: Moomba Wilton Pipeline; Wagga Lateral and Regional Laterals covered.

1.3 A Brief MSP History

The MSP was conceived and development commenced by AGL in the early 1970's to enable the continued existence and growth of the gas industry in NSW. It was compulsorily acquired by the Commonwealth Government in the early days of its development.

Under Government ownership the MSP was expanded to meet increasing demand for gas and extended to the major regional areas of NSW during the 1980s and 1990s. The MSP was sold by the Commonwealth into EAPL in 1994 under the Moomba Sydney Pipeline System Sale Act which also established the regulatory regime prior to the introduction of the Code in 1998.

In 1999 the MSP was linked to the Victorian gas transmission system via the pipeline extension known as the Interconnect, enabling flows to Victoria from NSW and to NSW from Victoria.

In September 2000, the EGP was completed. This pipeline links the Gippsland gas fields to the NSW/ACT gas market and competes with the MSP for transportation services into this geographic market segment.

IMPORTANT NOTICE

This Access Arrangement Information for the MSP replaces any previous, proposed or revised Access Arrangement Information documents submitted for the MSP.

Terms used in this revised Access Arrangement Information have the meaning given to them in the revised Access Arrangement.

Projections in this revised Access Arrangement Information are based on a number of assumptions. Although EAPL regards these assumptions as appropriate to base the projection on at the present time, EAPL cannot and does not make any representation or warranty as to the accuracy of the projections.

Due to rounding differences, the totals in tables in this revised Access Arrangement Information may not equal the sum of the elements of the table.

2. ACCESS & PRICING PRINCIPLES

2.1 Factors to be taken into account by a regulator

Section 2.24 of the Code requires the Regulator to take the following into account in deciding whether to approve a proposed Access Arrangement:

(a) service provider's legitimate business interests and investment in the covered pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons;

(c) operational and technical requirements required for safe and reliable operation of the covered Pipeline;

(d) economically efficient operation of the covered Pipeline;

(e) public interest, including in having competition in markets (whether or not in Australia); and

(f) interests of Users and Prospective Users.

Section 8.1 also requires that a Reference Tariff should be designed with a view to achieving the following objectives:

(a) providing the Service Operator with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting decisions in Pipeline transportation systems or in upstream or downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference Services.

2.2 Tariff Pricing Principles

In developing its proposed Services and Reference Tariffs in the Access Arrangement, EAPL has focussed on the following objectives:

- providing encouragement for the growth of natural gas markets;
- achieving greater utilisation of the pipeline;
- encouraging efficient use of the pipeline; and
- responding to competition from the EGP.

2.3 Reference Tariff Determination

2.3.1 Treatment of Mainline and Regional Laterals

For the purpose of developing Reference Tariffs the MSP has established two pipeline sub-systems. These pipeline sub-systems are designed to maximise the viability of gas supply for regional NSW users, while at the same time ensuring that the transportation charges for users of the Regional Laterals are cost reflective, as set out in Sections 8.38 and 8.42 of the Code. That is, a Reference Tariff is to be designed to recover all directly attributable costs, and a proportion of shared costs to the maximum extent technically and commercially reasonable. The Reference Tariffs have been designed so that revenues for the Regional Laterals cover the incremental costs of the Regional Laterals.

The two pipeline sub-systems are as follows:

- the Mainline, consisting of:
  - the main pipeline (from Moomba to Wilton);
  - the Wagga Lateral (from Young to Wagga Wagga);
  - the Interconnect[1] (from Wagga Wagga to Culcairn); and
  - the Canberra Lateral (from Dalton to Watson).

- the Regional Laterals, consisting of:
  - the Northern Lateral (from Young to Lithgow including Bathurst, Orange Oberon); and
  - the Griffith Lateral (from Burnt Creek to Griffith).

The use of these two pipeline sub-systems (Mainline and Regional Laterals) involves calculation of a different price path for each pipeline sub-system.

2.3.2 Price Paths

The Mainline and Regional Lateral tariffs have been designed to allow the recovery of efficient costs. At the same time the price paths avoid price "shocks" for Regional Lateral users and price "pleasures" to Mainline users.

Reference Tariffs for the Access Arrangement Period start with the current MSP Published Tariffs and follow a price path determined by applying the NPV methodology, as detailed in Section 5 below.

2.4 Reference Tariff Structure

Total transmission costs are most strongly related to two factors: firstly, length of pipeline, and secondly, and to a lesser extent, the maximum daily quantity (MDQ) transported. Reference Tariffs have therefore been structured around tariff components that reflect pipeline system utilisation in terms of distance and MDQ transported.

2.4.1 Volume Distance Methodology

[1] At the commencement of the Access Arrangement the Interconnect is not part of the covered Pipeline, but for the purposes of the Access Arrangement is treated as part of the Mainline.

The relationship between costs and length of pipelines is approximately linear apart from relatively small fixed costs such as metering. In setting cost reflective tariffs it is therefore appropriate to capture the length of pipeline or distance factor either by:

- Setting tariff charges on a distance basis; or
- Setting different charges for different geographical zones in a way that reflects distance overall but provides a postage-stamp rate within a zone.

Distance-based charges are more directly cost reflective than zonal or postage-stamp rates and do not create artificial by-pass opportunities at zone boundaries. Zonal charges are advantageous on systems with very large numbers of Receipt and Delivery Points, such as distribution networks. The MSP has relatively few Receipt and Delivery Points and EAPL has therefore historically adopted a distance-based structure for the Reference Tariffs, called a Volume Distance Methodology.

2.5 Cost Allocation

There is only one Reference Service offered. This is the Firm Service and the Reference Tariff for the Firm Service has two components that are designed to broadly reflect the fixed and variable components of transportation costs through the MSP. Fixed costs are allocated to the Capacity Charge and variable costs are allocated to the Throughput Charge. Costs are further allocated on a distance basis resulting in a tariff expressed as $/GJ/km.

As identified earlier there are different Reference Tariffs for the Mainline and for the Regional Laterals based on the costs of the Mainline and the Regional Laterals respectively.

2.6 Incentive Mechanism

The incentive mechanisms in the Reference Tariffs are:

- The level of Reference Tariff is designed to enable EAPL to develop the market for the Reference Service and other Services[2] in an environment of pipeline competition; and
- The prospect of retaining improved returns for the Access Arrangement Period provides an incentive to EAPL to increase the volume of sales and minimise the cost of providing Services;
- In developing Reference Tariffs for the next Access Arrangement Period, EAPL will ensure that Users and Prospective Users will share in benefits of increased efficiencies achieved by EAPL up to that date.

These incentive mechanisms will encourage to EAPL to reduce total operating costs and increase pipeline throughput.

[2] In accordance with Section 8.1(f) of the Code.

2.7 Other Revenue

The Reference Tariff has been designed to recover the revenue attributable to the Reference Service. No allowance has been made for other revenue that may accrue from any other charge incorporated in the Reference Tariff as these are not considered material.

3. CAPITAL COSTS AND REVENUE PATH

3.1 Asset Base

The ICB is to be determined by reference to a range of factors set out in Section 8.10 of the Code. In determining the ICB, consideration must also be given to the objectives set out Section 8.1 of the Code. Where there are conflicts between the application of the objectives, the regulators must apply Section 2.24 of the Code in exercising its discretion in determining the ICB.

These points were highlighted to the Commission in EAPL's 5 November 2002 submission concerning the impact of the Epic Decision on the Draft Decision. In addition, that submission highlighted errors of law in the Draft Decision. The errors that were identified related to the following:

- The interpretation of DORC as a maximum for the ICB;
- The effect of monopoly returns on the valuation of the ICB;
- The reasonable expectations of the Service Provider under the prior regulatory regime;
- The interpretation of the Code to include a "fairness" test, particularly in determining the ICB and the DORC methodology, and the definition of DORC as a backward looking methodology in relation to depreciation; and
- The impact of Section 2.24 and the legitimate business interests of the service provider.

It is clear that the Commission must reconsider the ICB for the MSP in the light of the Epic Decision and matters identified in EAPL's submission of 5 November 2002.

Pursuant to Section 8.10 the most significant factors in the context of the MSP are as follows.

3.1.1 Optimised Replacement Cost ("ORC")

EAPL estimated the ORC for the MSP for its 1999 Access Arrangement. EAPL has not revised the ORC, except for the removal of assets disposed of at the time of the establishment of APT in June 2000. The item called contingency in the 1999 ORC estimated by Venton and Associates[3] has not been removed because Venton has confirmed that this item does not refer to an allowance for overrun of costs, but is a cost component to cover small items that are not otherwise included in the methodology applied to estimate the ORC.

The ORC, broken down by pipeline and asset class, is set out in the following tables:

[3] Submission to Commission CWH to provide???

MSP ORC by Pipeline
($2000)

	ORC ($m)
Moomba Wilton Pipeline	879.5
Canberra Lateral	19.2
Northern Lateral	49.6
Griffith Lateral	30.8
Wagga Lateral	33.6
Interconnect	29.6
Total	**1,042.3**

MSP ORC by Asset Class
($2000)

	ORC ($m)
Pipelines – Moomba to Wilton	819.9
Pipelines – Young to Culcairn	59.4
Pipelines – Laterals	90.8
Compressors	58.1
Metering	14.0
Plant, Machinery, Equipment	0.0
Mobile Equipment	0.0
Total	**1,042.3**

Note: There are rounding differences in this table.

3.1.2 Depreciated Optimised Replacement Cost ("DORC")

DORC has been calculated by reference to the NPV methodology for deriving DORC from ORC. This forward-looking methodology is consistent with the methodology and meaning of DORC as set out in the Commission's Draft Statement of Regulatory Principles and the 1998 Final Decision on the Victorian gas transmission system now owned by GasNet. It is also consistent with the evidence accepted by the WA Supreme Court in the Epic Decision and with the view expressed by the Commission's consultants[4].

The following table sets out the DORC (adjusted for asset disposals in June 2000) broken down by pipeline.

[4] The justification for the use of an NPV methodology has been detailed in a number of submissions by EAPL and its advisors. NERA also provided a report to the Commission supporting the calculation of DORC on an NPV basis (using costs).

MSP DORC by Pipeline
($2000)

	DORC ($m)
Moomba Wilton Pipeline	813.4
Canberra Lateral	18.3
Northern Lateral	48.2
Griffith Lateral	30.5
Wagga Lateral	32.0
Interconnect	29.7
Total	972.3

EAPL has not calculated an NPV based DORC for the individual classes of assets.

3.1.3 Economic Written Down Value

The economic written down value of the MSP which reflects past under-recoveries of depreciation and return on assets reflects the original intention that the pipeline's costs would be recovered over its life with early under-recoveries being recouped in later years.

Based on the Commission's calculations of the economic written down value at 30 June 1994 of $1,291 million EAPL has estimated a value of **$1,700 million** at 30 June 2000.

3.1.4 Reasonable Expectations under the Prior Regulatory Regime

Section 8.10 (g) of the Code requires the Commission to take into account the reasonable expectations of persons under the regulatory regime that applied to the MSP prior to the commencement of the Code. This value had previously been estimated by EAPL on a preliminary basis as being greater than $666 million. Following the Epic Decision, EAPL fully re-estimated the value of the MSP attributable to its reasonable expectations under the prior regulatory regime, taking into account the reasoning of the WA Supreme Court. EAPL's calculations of the value of its reasonable expectations are soundly based on corporate documents prepared by it prior to the introduction of the Code[5]. This value is now estimated to be in the range of **$784 million - $998 million**[6] as at 1 July 2000.

3.1.5 Purchase Price

The value obtained by EAPL in purchasing the MSP from the Commonwealth in 1994, as assessed by EAPL, significantly exceeds the purchase price of $534 million. There is no evidence to support the view expressed in the Draft Decision that the sale price accepted by the Commonwealth reflected an intention on the part of the Commonwealth to preserve an implied subsidy to NSW gas consumers.

5 EAPL provided copies of the documents to the Commission on a confidential basis.

6 See EAPL's 5 November 2002 submission to the Commission on the impact of the Epic Decision on the Commission's Draft Decision on the MSP Access Arrangement.

3.1.6 Initial Capital Base

The Code requires consideration of a number of valuation methodologies which, in the case of the MSP, range up to $1,700 million. The relevant valuations are significantly greater than the ICB proposed in the Draft Decision.

The proposed ICB is now **$784 million**. To arrive at an ICB less than the bottom end of the range attributable to EAPL's reasonable expectations under the prior regulatory regime represents a confiscation of value from EAPL and a windfall to users[7].

Appropriately the proposed ICB of $784 million also reflects the fact that correcting the errors in the Draft Decision must lead to a substantial increase in the ICB above the value of $539 million proposed in the Draft Decision[8].

In addition, EAPL notes that in taking into account the matters in Sections 8.1 and 2.24 of the Code (as is now clearly required in the light of the Epic Decision) the value of $784 million does not represent a maximum possible value for the ICB, but is a minimum value which would properly recognise the interests of EAPL as required under the Code while still recognising the interests of users.

It is also important to note that, as identified in EAPL's 5 November 2002 submission, DORC does not necessarily represent a constraint on the ICB. Even if the Commission calculated a DORC value less than the value represented by EAPL's reasonable expectations, the circumstances associated with the sale of the MSP are sufficiently unusual to justify a determination of ICB outside the "normal" range of between DORC and DAC.

Asset Disposals since the 1999 Access Arrangement

As a consequence of the establishment of APT and associated outsourcing arrangements, certain of EAPL's non-pipeline assets were disposed of in June 2000. Included in the assets disposed of were the SCADA system, motor vehicles, tools, plant and mobile equipment.

The ICB in the revised Access Arrangement includes adjustments for disposal of assets arising from the formation of APT. The adjustments to the ICB for disposals were based on ORC and DORC values in the 1999 Access Arrangement Information. The value of the assets disposed is as follows:

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[7] EAPL's submission of 5 November 2002 to the Commission submitted that the appropriate ICB is represented by the NPV of cashflows that EAPL would have reasonably expected under the regulatory regime prior to the introduction of the Code. EAPL calculated a range of $768 million - $972 million. This range has now been corrected to $784 million - $998 million.

[8] In addition to errors identified in EAPL's 5 November 2002 submission to the Commission a number of other errors were identified in EAPL's 14 March 2001 response to the MSP Draft Decision.

MSP Assets Disposed
($2000)

	ORC* ($m)	DORC* ($m)	Revised AA Deemed Disposal Value ($m)
Plant, machinery & equipment	10.3	4.8	2.0
Mobile Equipment	6.0	3.0	3.0

Note: * From Access Arrangement 1999 (p27)

The ICB was adjusted downward for disposals by $5.0 million ($2000) to arrive at an adjusted ICB of $779 million ($2000) as follows:

Initial Capital Base by Pipeline
($2000)

	ICB ($m)	% of ORC
Moomba Wilton Pipeline	657.3	84.4
Canberra Lateral	14.4	1.9
Wagga Lateral	25.1	3.2
Regional Laterals	60.1	7.7
Interconnect	22.1	2.8
Total	779.0	100.0

3.2 Economic Lives and Remaining Economic Lives

Economic lives for the various assets making up the MSP have been established based on APT's experience as major owners and operators of Australian pipelines together with various recent access arrangements proposed by service providers, submissions of industry participants and decisions of Regulators. These are set out in the table below together with the average remaining economic life of each of the asset classes making up the MSP.

Asset Economic Lives (from installation and remaining years)

Asset	Economic Life (years)	Remaining Life (years)
Transmission Pipelines	80	53
Compressor Stations#	25-50	10-35
Regulation and Metering Stations	50	23-49
Plant and equipment	5-20	0-20
Buildings	50	23

Note: # A compressor station's remaining life depends on both its age and the level of usage.

3.2.1 Back-ending Depreciation (Economic Depreciation)

The use of the NPV methodology allows for "back-ending" of depreciation, which provides greater opportunities to grow the market, particularly in regional centres.

For the MSP, this means that during the early Access Arrangement Periods estimated returns will not be sufficient to cover the total costs (including profit and straight-line depreciation) of providing the Reference Services. While this applies to both the Mainline and the Regional Laterals, the level of under-recovery for the Regional Laterals is very significant in early years. Accordingly, there is a need for a mechanism to provide for the under-recovery of revenue in the early years of the MSP's life to be recouped in the later years of operation.

The concept of back-ended depreciation – which often arises where the NPV methodology is applied – provides such a mechanism and, in respect of the MSP, is necessary to achieve the Code objective which requires that the Reference Tariffs be designed with a view to providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service[9].

Application of back-ended depreciation to the MSP is also consistent with the provisions of Section 8.33(a) of the Code, which provides that the depreciation schedule[10] should be designed:

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

This section of the Code recognises that such a mechanism is necessary to justify commitment to major infrastructure projects, and that this objective outweighs any argument that the ability to roll forward estimated under-recovery lessens incentives for efficiency. In addition, the Code recognises that inherent in investment in pipelines is a significant market risk associated with demand forecasts. What is unusual in the case of the MSP is that a significant element of its market risk arises because of an unregulated competing pipeline - that is the EGP.

The Commission has accepted that the depreciation approach adopted by EAPL is consistent with Code principles[11] in it Final Decision on the Central West Pipeline.

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[9] Section 8.1(a).

[10] Application of depreciation principles to the IRR/NPV methodology is addressed in Section 8.34 of the Code, which includes reference to Section 8.33.

[11] CWP Final Decision p71

3.3 Estimated and Committed Capital Expenditure

The amounts estimated for capital expenditure are set out in the table below[12].

Forecast of Capital Expenditure
($2001, $m)

	2003	2004	2005	2006	2007	2008
Northern Lateral Capacity Expansion	-	-	-	4.05	-	-
In-line Inspections	-	2.70	-	-	-	-
Compressor overhaul	-	--	1.10	-	-	1.10
Stay-in-Business	0.64	0.40	0.40	0.40	0.40	0.90
TOTAL	0.64	3.010	1.50	4.45	0.40	2.00

Note: The forecast capital expenditure for 2003 is from 1 October 2002 onwards only.

3.3.1 Justification of capital expenditure

The revised Access Arrangement contains proposed capital expenditure during the Access Arrangement Period. In addition to annual stay-in-business capital expenditure, periodic intelligent pigging (in-line inspections) and compressor overhauls, there is one capacity expansion proposed for the Northern Laterals as discussed below.

Stay-in-business

This is capital that is necessary for continued operation of the business and includes minor capital equipment. Estimates are based on historic experience of requirements and are small in magnitude.

Periodic in-line inspections

Under the Pipeline Licence conditions for the MSP and as part of sound routine maintenance EAPL is required to undertake periodic in-line inspections using intelligent pigging techniques. The estimated cost reflects EAPL's historic costs and current industry knowledge.

Compressor overhauls

Maintenance programs for compressors involve overhauls of both gas turbine driver and the compressor units. These overhauls are undertaken after completion of operational hours set by the equipment manufacturers. The estimated costs reflect EAPL's historic experience of the costs of overhauls and quotations from the manufacturer.

[12] These estimates reflect the assumed levels and timing of replacement of components. Although EAPL regards these assumptions as appropriate to base its capital expenditure estimates on at the present time, EAPL cannot and does not make any representation or warranty as to the accuracy of the estimates presented.

Northern Lateral Expansion

The 1999 Access Arrangement did not forecast any capacity expansion on the Northern Lateral in the initial Access Arrangement Period.

The Northern Lateral has a single reciprocating compressor (called the Young-Lithgow or YL Compressor), to boost delivery pressures at the Lateral's extremities in peak periods. There is no backup unit in the event of compressor failure. While this unit has historically operated for short periods in winter only, recent modelling indicates that substantial growth in the area will result in peak system constraints that may require expansion as early as 2004, but will definitely be required by 2006.

The Northern Lateral compressor will be increasingly used to assist the northbound flow of gas through the Interconnect in the shoulder and summer periods. This use of the unit will result in greater likelihood of unplanned interruption and maintenance.

The capital cost of expanding the Northern Lateral capacity in 2006 is estimated at $4.0 million, based on the cost of adding an additional reciprocating compressor unit to the existing station with 50% higher power rating (600 kW) compared with the current compressor unit (400 kW).

New Facilities Investment tests

For the proposed capital expansion, the requirement to expand is not based solely on an achieving a specific volume target. The requirement to expand depends on number of factors, including but not limited to, system or lateral peak day volume requirements, system or lateral minimum pressure requirements, and specific delivery point volume constraints (daily and/or hourly).

The expansion is justified on a combination of the tests under Section 8.16(b) of the Code. A different mix of the tests applies to each expansion as follows:

<u>Northern Lateral Expansion</u> - As growth in load is the main driver for this expansion, the anticipated incremental revenue generated by the additional capacity is expected to cover a significant proportion of the costs of the expansion (test (i)).

Continuing load growth on both the Northern Lateral and increasing use of the Interconnect will require the installation of a duplicate compressor to allow for periods of planned and unplanned maintenance. The investment in capacity expansion is needed to provide system wide benefits of security of supply (test (ii)) and to maintain the integrity and Contracted Capacity of Services (test (iii)).

Replacement capital expenditure

The capital expenditure forecast during the Access Arrangement Period does not incorporate any significant capital expenditure for replacement of assets. Some minor replacement is incorporated into the SIB capital expenditures and is not identified on a specific project basis.

3.4 Rate of Return

3.4.1 WACC Approach

EAPL has adopted the weighted average cost of capital (WACC) approach using the capital asset pricing model (CAPM) in determining an appropriate rate of return for the MSP. A pre-tax real WACC is preferred for a number of reasons:

- It is simple to apply when modelling, only requiring calculation of pre-tax cash flows or EBITs.
- It avoids the requirement for complex notional tax calculations.
- Its use reflects the imprecision of estimating the WACC, recognising that many of the variables used to calculate WACC have a wide range of uncertainty. It also reflects the fact that the formulae used to calculate the WACC are open to debate even among academics and experts.

3.4.2 WACC Parameters

Rather than specify a range for the variables, specific values have been chosen that reflect an appropriate point in the range that will avoid inappropriate and undesirable under estimation of the WACC[13]. The following table sets out the parameters and underlying assumptions used in the revised Access Arrangement.

WACC Parameters

	Parameter
Real Risk Free Rate (rr_f)	3.35%
Inflation (f)	2.69%
Nominal Risk Free Rate (r_f)	6.13%
Debt to Total Assets	60%
Effective Tax Rate (T)	30%
Imputation Credit Value (γ)	0.5
Asset Beta (β_a)	0.62
Debt Beta (β_d)	0.06
Equity Beta (β_e)	1.45
Market Risk Premium (MRP)	6.0%

The following formulae are used to derive the pre-tax real WACC and intermediate variables.

Pre Tax Nominal = $R_e / (1 - T * (1 - \gamma)) * E/V + r_d * D/V$

Post Tax Nominal = $(R_e * ((1 - T)/(1 - T * (1 - \gamma))) * E/V + r_d * (1 - T) * D/V$

[13] There is a significant body of evidence and opinion which points to the likely adverse consequences of underestimating WACC and other components of regulated revenue eg Productivity Commission Review of National Access Regime, 2001.

Where:

R_e	=	Cost of Equity
T	=	Corporate tax rate
γ	=	Imputation credit take up rate
E	=	Equity
D	=	Debt
V	=	Debt plus Equity
r_d	=	Cost of Debt

3.4.3 Justification for each parameter.

- **Nominal risk free rate**: EAPL has taken the 40 day average 10 year bond rate to 28 March 2002 to arrive at the proposed nominal risk free rate of 6.13%. This is consistent with Commission's approach in the Draft Decision.

- **Inflation rate:** EAPL has taken the 40 day average 5 year bond rate to 28 March 2002 and the August 2005 Treasury Indexed Bonds to arrive at the inflation rate of 2.69% (by Fischer Equation). This is consistent with Commission's approach in the Draft Decision.

- **Real risk free rate:** EAPL has calculated the real risk free rate as the difference between the nominal risk free rate and the inflation rate (by Fischer Equation). This is consistent with Commission's approach in the Draft Decision.

- **Gearing:** The industry standard structure of 60% debt has been adopted. This is consistent with the approach in the Draft Decision, and other regulatory decisions by the Commission, Essential Services Commission (Victoria)[14] and the Independent Pricing and Regulatory Tribunal (NSW).

- **Asset beta:** A recent study of equity betas by Allen Consulting arrived at an unprecedentedly low estimate of equity betas for regulated pipeline infrastructure, as a result of a number of flaws. EAPL has provided a submission to the Commission that highlights major areas of error in the report. It is clear that such a published report should be subject to proper peer review.

  EAPL has estimated the asset beta to 0.62 to reflect the pipeline's exposure to:

  - increased competition from alternative energy sources;
  - increased competition from the EGP;
  - uncertainties with deliverability from Moomba and the development of alternative gas sources; and
  - increased risk from the development of coal seam methane in NSW that bypasses the MSP. The recent market initiatives of Sydney Gas demonstrates that coal seam methane represents an genuine alternative source of gas for the Sydney market over gas sourced via the MSP.

[14] Previously, Office of the Regulator General.

- **Debt beta:** EAPL has adopted the Commission's estimate of the debt beta of 0.06.

- **Equity Beta:** EAPL has calculated the equity beta from the asset and debt betas using the formula below.

$\beta_e = \beta_a + (\beta_a - \beta_d) * (1 - (rd / (1 + r_d))) * (1 - \gamma * T) D / E$

Where:

β_e	=	Equity Beta
β_a	=	Asset Beta
β_d	=	Debt Beta
r_d	=	Cost of Debt
γ	=	Imputation credit take up rate
T	=	Corporate tax rate
D	=	Debt
E	=	Equity

- **Market Risk Premium:** A market risk premium of 6.0% has been adopted as representing the most appropriate value. This value has generally been accepted by regulators. It is one of two major variables in the CAPM which has a wide range of uncertainty in estimates.

  Some recent studies have estimated lower values for the market risk premium. However, the correctness of the results of these studies is questionable because the measurements used relatively short periods and consequently considered a limited lifecycle of risk. They therefore may not properly reflect the community's attitude to risk. In the light of the Productivity Commission's clearly articulated view about the deleterious impact of underestimating efficient costs, adoption of a lower value should be avoided.

- **Effective tax rate:** EAPL has adopted the current statutory tax rate (30%). The statutory tax rate is appropriate because to apply effective tax rates that reflect the benefit of depreciation allowances and other tax policy initiatives of government results in the confiscation of benefits consciously conferred by government thereby overriding government policy designed to promote investment.

- **Imputation Credit Value:** A study by Lally for the Commission suggesting that a value of 100% should be adopted lacks appropriate peer review. To date EAPL is not aware of any study that measures the actual value placed on imputation credits by investors. Studies have tended to focus on the rate of uptake of imputation credits. To equate the uptake rate with value to investors is likely to be flawed. EAPL has adopted the estimate of 50% for the value of imputation credits as generally accepted in regulatory decisions.

3.4.4 WACC Results

The resulting estimates of cost of equity, cost of debt and WACC are as follows:

WACC

	Percent
Nominal Cost of Equity (r_e)	14.84
Nominal Cost of Debt (r_d)	7.33
Pre Tax Real WACC (W_{tr})	7.90

4. NON-CAPITAL COSTS: OPERATIONS AND MAINTENANCE, OVERHEADS AND MARKETING[15]

Estimates of Non-Capital costs or operating expenditure have been developed by EAPL for the period October 2002 to 30 June 2008. Pursuant to Section 8.2(e) of the Code, the forecasts of operating expenditure detailed in this section represent best estimates arrived at on a reasonable basis.

The efficiency of the estimated operating expenditure incurred in operating the MSP is demonstrated in Section 7. EAPL believes that there are no readily achievable efficiency gains to be made which would significantly reduce the operating expenditure forecast.

4.1 Operations and Maintenance Costs

Operating costs represent the direct costs of operating and maintaining the Mainline and Regional Laterals. Operating activities undertaken include continuous monitoring, operation and control of the:

- Pipeline,
- Pipeline right of way,
- Pipeline facilities, and
- Compressor stations.

Maintenance activities undertaken include the maintenance of the:

- Pipeline,
- Pipeline right of way,
- Pipeline facilities,
- Pipeline SCADA and communications system, and
- Regulation metering and gas measurement equipment.

APT has elected to outsource a substantial proportion of its operational activities to Agility, which provides asset management services and field services under an agreement with APT for each of its pipelines including MSP. As a consequence a significant proportion of the MSP's operations and maintenance work is carried out under APT's agreement with Agility.

Operating cost estimates are based on actual costs expected to be incurred over the Access Arrangement Period. There has been no allowance for contingency in respect of the operating costs over the life of the MSP.

No allowance has been made for system use gas in the operating costs, since system use gas will be provided by the users.

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[15] Projections in this Section are based on a number of assumptions. Although EAPL regards these assumptions as appropriate to base the projection on at the present time, EAPL cannot and does not make any representation or warranty as to the accuracy of the projections.

4.2 Overheads and Marketing Costs

Overhead costs (ie Administration and General) include expenditure relating to:

- Insurances,
- Directors fees,
- Regulatory activities,
- Compliance and general corporate governance,
- Personnel and training,
- Legal,
- Accounting,
- Taxation, and
- Government levies.

As a result of the creation and float of APT, EAPL is a subsidiary of APT and is managed within APT's corporate structure. APT is a listed managed investment scheme.

The fact that APT is a listed entity and has major outsourcing arrangements means that the cost structures for EAPL are vastly different from those applying at the time of the original Access Arrangement proposed in May 1999. EAPL now shares a significant level of cost associated with APT's operation as a listed entity that were either not present or not recognised under EAPL's ownership prior to the establishment of APT.

In addition, a number of previously unaccounted for cost elements are now evident as a result of the establishment of APT. These include Board costs covered by EAPL's previous owners and significant technical expertise previously held within the AGL Pipelines Group from which EAPL benefited at no cost. As a result EAPL's corporate overhead costs now fully reflect the actual cost of its operation.

Sales and Marketing costs include expenditure relating to:

- Development and promotion of gas transportation and ancillary services,
- Investigation and feasibility studies for potential gas consuming projects,
- Commercial negotiations relating to gas transportation services, and
- General contract management and administration activities.

4.3 Fixed versus Variable Costs

Variation of operating costs with throughput is negligible. Consequently EAPL has not sought to allocate operating expenditure between fixed and variable.

4.4 Cost Allocation

All of the operating expenditures are fully allocated to the Reference Service specified in the MSP Access Arrangement in proportion to the Mainline and Regional Laterals ORCs.

ORC represents an appropriate index for the allocation of operating costs as it incorporates pipeline length, impact of compressors and offtake stations and pipe diameter, as discussed in Section 7.2.2 below.

4.5 Total Operating Expenditure Costs

Estimated operating costs for the Access Arrangement Period have been included in the tables below. These costs include all asset management services and field services relating to the MSP, and as previously noted, will be carried out under contract by Agility.

Forecast Operating Expenditure by Mainline and Regional Laterals
($2001, $m)

	2003#	2004	2005	2006	2007	2008
Mainline	15.95	21.39	21.31	21.31	21.31	21.31
Regional Laterals	1.33	1.79	1.78	1.78	1.78	1.78
Total	17.28	23.18	23.09	23.09	23.09	23.09

NOTE: # 2003 is for 9 month Access Arrangement period (1 Oct 02 to 30 June 03).

Forecast Operating Expenditure by Expenditure Category
($2001, $m)

	2003#	2004	2005	2006	2007	2008
Operations and Maintenance	13.25	17.93	17.81	17.79	17.76	17.73
General and Administration	2.74	3.56	3.60	3.65	3.69	3.74
Sales and Marketing	1.29	1.69	1.67	1.66	1.64	1.62
Total	17.28	23.18	23.09	23.09	23.09	23.09

NOTE: # 2003 is for 9 month Access Arrangement period (1 Oct 02 to 30 June 03).

Forecast Operating Expenditure by Detailed Expenditure Category
($2001, $m)

	2003#	2004	2005	2006	2007	2008
Labour	0.18	0.25	0.25	0.26	0.27	0.27
Corporate Overheads	1.54	2.12	2.17	2.21	2.26	2.30
Materials (and Supply)*	15.41	20.64	20.50	20.47	20.40	20.35
Communication Systems	0	0	0	0	0	0
Gas Used	0	0	0	0	0	0
Licences	0.13	0.17	0.17	0.17	0.17	0.17
Total	17.28	23.18	23.09	23.09	23.09	23.09

NOTE: # 2003 is for 9 month Access Arrangement period (1 Oct 02 to 30 June 03).
* Including services provided by others.

5. TOTAL REVENUE

5.1 NPV Methodology

The Code provides that one of three calculation methodologies can be used to determine Total Revenue. EAPL has adopted the “NPV” approach whereby the NPV of Total Revenue equals the NPV of forecast costs of the pipeline over the Access Arrangement Period, taking into account the residual value of the Capital Base. The total required revenue is calculated on the basis of:

- forecast operating costs;
- a rate of return on the investment; and
- the Capital Base at the beginning and at the end of the Access Arrangement Period.

An alternative way of considering this methodology is to view it in similar terms as the cost of service methodology. That is the total revenue is calculated as the sum of:

- forecast operating costs;
- a rate of return on assets; and
- economic depreciation.

Economic depreciation is the difference between the revenue *less* operating costs *less* return on assets. Where revenue is insufficient to recover operating costs *plus* a return on assets, economic depreciation is negative (there is an under-recovery of costs) and is added to the Capital Base. When revenue increases so that it exceeds operating costs *plus* the required return on assets, the result is positive economic depreciation and the asset base is reduced.

The NPV methodology solves iteratively for a revenue and price path that will arrive at a capital base of value zero at the end of the economic life of the pipeline. The value of the capital base at the end of the Access Arrangement Period is the residual value applicable under the NPV methodology and is the PV of the estimated cash flows over the economic life of the pipeline from the end of the Access Arrangement Period based on the price path from that point.

The methodology utilising economic depreciation to determine the revenue path for the Mainline and Regional Laterals is the same methodology as adopted for the Commission approved Central West Pipeline Access Arrangement. The Commission has accepted that this depreciation approach is consistent with Code principles.

Total Revenue to be recovered from the sales of all Reference Services during the Access Arrangement Period is based on the following assumptions:

- a pre-tax real return of 7.90% (refer Section 3.3)
- an adjusted ICB of $779 million (refer Section 3.1),
- The Capital Base is adjusted each year to:
  - include estimated New Facilities Investment (refer Section 3.3);
  - reflect economic depreciation (refer Section 3.2);

- take account of inflation (ie indexing the Capital Base using the approach outlined below); and
- forecast operating expenditure (refer Section 4).

5.2 Rolling Forward the Capital Base to 2003

To apply the NPV methodology from 1 October 2003 (ie from the commencement of the Access Arrangement), the ICB as at 1 July 2000 had to be rolled forward. The roll forward of the ICB for the Mainline and Regional Laterals from 1 July 2000 to 30 June 2002 is as follows:

Asset Base Roll Forward – Mainline
($2000, $m)

Period Ending	**2001**	**2002**
Opening Asset Base	718.86	697.68
Capital Expenditure	0.66	0.96
Economic Depreciation	(21.84)	(8.64)
Closing Asset Base	697.68	689.99

Asset Base Roll Forward – Regional Laterals
($2000, $m)

Period Ending	**2001**	**2002**
Opening Asset Base	60.14	61.79
Capital Expenditure	0.04	0.03
Economic Depreciation	1.61	2.72
Closing Asset Base	61.79	64.54

5.3 Indexing the Capital Base

As part of the economic depreciation approach to the NPV methodology the Capital Base is indexed each year using the CPI. This is consistent with the use of a real rate of return as adopted by EAPL.

5.4 Total Revenue Calculation

The tables below set out the estimated total revenue for each year of the Access Arrangement Period.

Total Revenue – Mainline
($2000, $m)

Period Ending	2003#	2004	2005	2006	2007	2008
Regulatory Asset Base	**689.99**	**685.09**	**683.37**	**683.83**	**683.25**	**684.76**
Return on Capital	36.35	54.13	54.00	54.03	53.99	54.11
Total Operating Costs	15.52	20.83	20.75	20.75	20.75	20.75
Economic Depreciation	1.94	4.50	0.97	0.93	(1.15)	(5.07)
Total Revenue	**53.81**	**79.47**	**75.72**	**75.72**	**73.59**	**69.79**

NOTE: # Total revenue for 2003 is for 9 month Access Arrangement period (1 Oct 02 to 30 June 03).

Total Revenue – Regional Laterals
($2000, $m)

Period Ending	2003#	2004	2005	2006	2007	2008
Regulatory Asset Base	**64.54**	**67.53**	**70.69**	**73.61**	**80.39**	**83.44**
Return on Capital	3.40	5.34	5.59	5.82	6.35	6.59
Total Operating Costs	1.29	1.74	1.74	1.74	1.74	1.74
Economic Depreciation	(2.10)	(2.93)	(2.89)	(2.81)	(3.02)	(2.92)
Total Revenue	**2.59**	**4.15**	**4.44**	**4.74**	**5.06**	**5.41**

NOTE: # Total revenues for 2003 is for 9 month Access Arrangement period (1 Oct 02 to 30 June 03).

The depreciation methodology of the pipeline provides a residual for the pipeline segments of:

Residual Values
($2000, $m)

Residual Values	2008
Mainline	691.70
Regional Laterals	86.43

5.5 Allocation of Total Revenue

After calculation of total revenue for the two pipeline sub-systems, the revenue is allocated to Reference Tariffs which are structured into Volume-Distance charges: the Capacity Charge and the Throughput Charge. Revenue is allocated between Capacity and Throughput charges in the ratio 96.0% to 4.0%. This ratio is broadly reflective of the ratio between fixed and variable costs for the MSP and is implied in EAPL's current Published Tariffs.

EAPL has not sought to recalculate the ratio of fixed to variable costs for the MSP from that implied in the Published Tariffs. However, it is reasonably confident that, if recalculated, the ratio would show a higher proportion of fixed costs than 96.0%. Users generally have a preference for the balance of charges to be towards the Throughput Charge rather than Capacity Charges (ie a higher variable component) as this reduces the cost associated with unutilised capacity reservation. To reallocate charges to have a higher variable (Throughput Charge) component would reduce the cost reflectivity of charges and provide a windfall to users with a peaky demand to the detriment of users with a flat load profile, who are better able to manage their demand and thereby release capacity for other users.

Once allocated to Capacity Charges and Throughput Charges, revenue is effectively allocated to capacity and distance for the Capacity Charges, and throughput and distance for the Throughput Charges, by dividing by the total forecast capacity-distance product and throughput-distance product for the MSP in each year.

5.6 Summary of Results

The results of Total Revenue and tariff path calculations are as follows:

5.6.1 Price Path

The X values for the pipeline using escalation formula below are:

Mainline X (X_{ML})	=	+ 0.33% (ie positive 0.33%)
Regional Laterals X (X_{RL})	=	– 4.00% (ie negative 4.00%)

The escalation formula is:

$RT_n = RT_{n-1} \text{ x } (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}) \text{ x } (1 - X)$

Where:

RT_n	=	Reference Tariff in year n
RT_{n-1}	=	Reference Tariff in year $_{n-1}$
CPI	=	means Consumer Price Index (All Groups – weighted Average Eight Capital Cities) published quarterly by the Australian Bureau of Statistics. If the Australian Bureau of Statistics ceases to publish the quarterly value of that index, then CPI means the quarterly values of another Index which EAPL reasonably determines most closely approximates that Index.
CPI_n	=	means the CPI published for the March quarter in $year_n$
CPI_{n-1}	=	means the CPI published for the March quarter in $year_{n-1}$
X	=	as defined above.

The Reference Tariff for the first partial year the proposed Access Arrangement period (1 Oct 02 to 30 June 03) is:

MSP Revised Access Arrangement Reference Tariffs, Mainline and Regional Laterals ($2002 for 01 Oct 02 – 30 June 03)

Capacity Charge:	0.04764	Cents/GJ/km/d
Commodity Charge:	0.00299	Cents/GJ/km

The above tariffs are identical to the current 2002 MSP Published Tariffs for Firm Transportation. The above tariff, when expressed in dollars per terajoule per kilometre per month is as follows:

MSP current Published Tariffs
($2002 for 01 Oct 02 – 30 June 03)

Capacity Charge:	$ 14.5000	/TJ/km/month
Commodity Charge:	$ 0.0299	/TJ/km

5.7 Proposed Approved Variation Methodology

EAPL's proposed Approved Reference Tariff Variation Methodology reflects Sections 8.7, 8.8 and 6.3 of the revised Access Arrangement. It is a combination of

- a price path approach using CPI-X formula as described (Section 5.6.1 above and Section 8.8 of the revised Access Arrangement), and
- a Trigger Event Adjustment Approach.

The Specified Events under the Trigger Event Adjustment Approach are:

- the introduction of new or increased government taxes, charges, levies, imposts or fees that occurs relative to those applicable at 30 April 2002 (Section 8.7 of the revised Access Arrangement);
- the introduction of Full Retail Contestability in NSW, the ACT or Victoria which leads to the introduction of new legal or procedural requirements affecting the management or operation of the pipeline (Section 6.3 of the revised Access Arrangement). In that event:
    - the user must reimburse the proportion of EAPL costs of complying with or responding to those requirements; and
    - EAPL is entitled to vary the terms of Transportation Agreements after consultation with users to give effect to the reimbursement.

6. SYSTEM CAPACITY AND VOLUME ASSUMPTIONS

6.1 System Definition

The MSP consists of a:

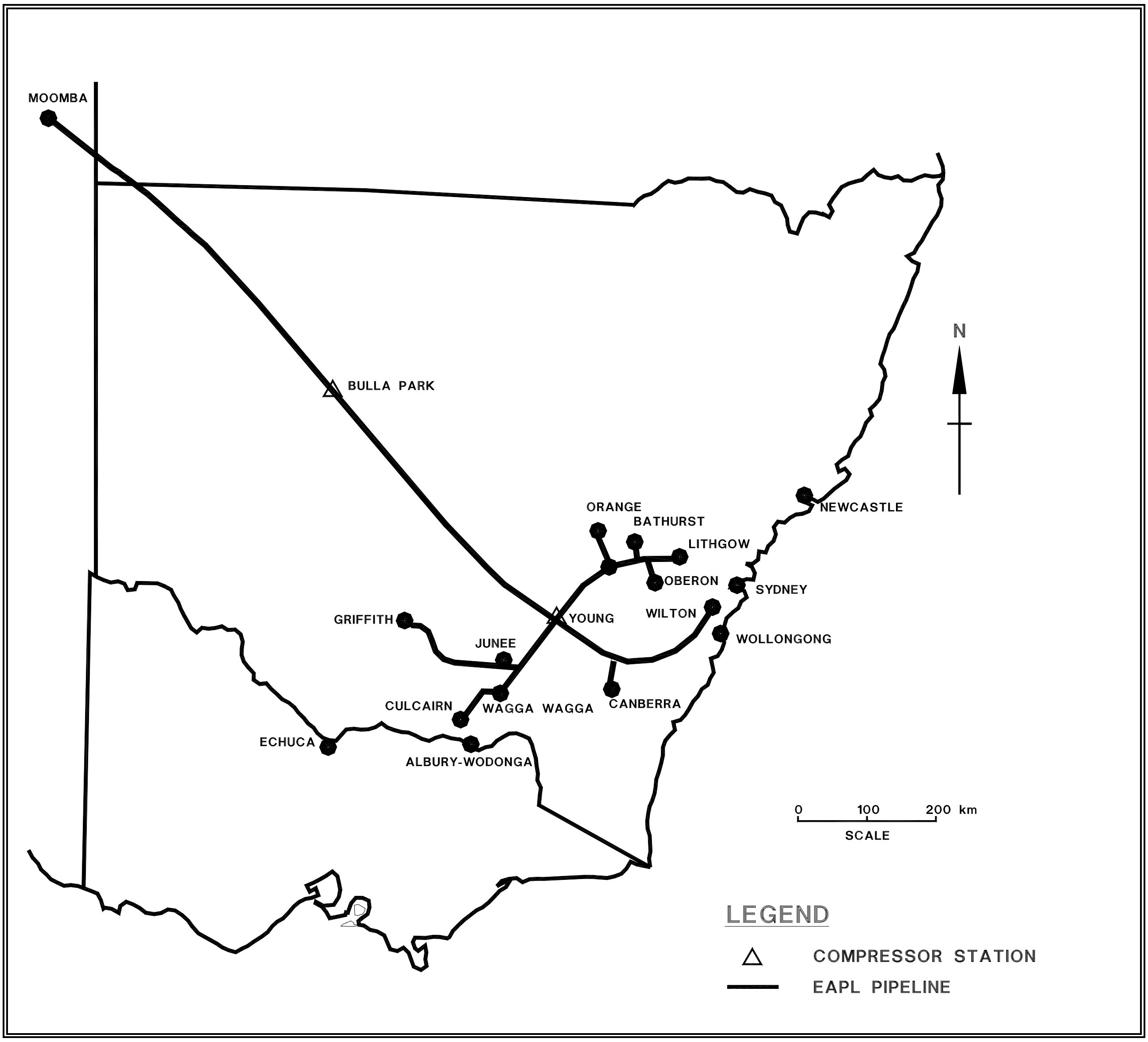
- pipeline from Moomba to Wilton (**"Moomba Wilton Pipeline"**);
- pipeline from Dalton to Canberra (**"Canberra Lateral"**);
- pipeline from Young to Lithgow (**"Northern Lateral"**);
- pipeline from Young to Wagga Wagga (**"Wagga Lateral"**);
- pipeline from Burnt Creek (on the Wagga Lateral) to Griffith (**"Griffith Lateral"**); and
- pipeline from Wagga Wagga to Culcairn (**"Interconnect"**).

Moomba Wilton Pipeline, the Wagga Lateral, the Canberra Lateral and the Interconnect are jointly referred to as the **"Mainline"** in this Access Arrangement Information. The Northern Lateral and the Griffith Lateral are jointly referred to as the **"Regional Laterals"**.

Other than the Interconnect, at commencement of this Access Arrangement the pipelines referred to in clause 6.1 are covered. The Interconnect is treated as part of the Mainline for the purposes of this Access Arrangement.

6.2 Map of MSP and Pipeline Specification

EAST AUSTRALIAN PIPELINE LIMITED
NATURAL GAS PIPELINE SYSTEM



PIPELINE SYSTEM SPECIFICATIONS
AS AT JUNE 2003

	Moomba Wilton Pipeline	**Wagga Lateral**	**Canberra Lateral**	**Northern Lateral**	**Griffith Lateral**	**Interconnect**
Construction Commenced	1974	1980	1981	1986	1993	1998
Pipeline Commissioned	1976	1981	1981	1987	1993	1998
Length (km)	1299	131	58	270	179	88
Diameter (mm)	864	324/89	273	168/114	168	457
Wall Thickness	8.3/9.2/13.3	6.4/7.9/5.5	6.4	4.8/6.4/6.0	4.8	7.0
Grade of Steel	API 5L X-65	API 5L X-46 API 5L L Grade B	API 5L X-46	API 5L X-46 API 5L L Grade B	API 5L X-42	API 5L X-70
Coating	Coal tar enamel	Extruded P.E.	Extruded P.E.	Extruded P.E.	Extruded P.E.	Extruded P.E.
Lining	Epoxy paint	Epoxy paint	Epoxy paint	Epoxy paint	Unlined	Unlined
Max. Design Pressure (kPa)	6895	8509	7800	9930	10200	10200
Max. Operating Pressure (kPa)	6378 to Bulla Park 6200 from Bulla Park to Wilton	6200	6200	9930	6200	10200
Compressor Stations	Bulla Park (2 x 4.4 MW ISO) Young (2 x 4.5 MW ISO)			Young (existing) (1 x 0.4MW ISO) 2nd Young unit in future		Uranquinty in future
Meter Stations (Note 1)	Marsden, Goulburn, Marulan, Moss Vale, Bowral, Wilton	Young, Cootamundra, Burnt Creek, Illabo & Bomen (Wagga Wagga)	Watson (Canberra)	Blayney, Orange, Cowra, Bathurst, Oberon, Lithgow		Culcairn, Uranquinty
Lateral Offtakes	Marsden, Young, Dalton	Cootamundra & Burnt Creek	Nil	Orange, Bathurst, Brewongle (Oberon)	Junee	Nil
Scraper Stations	10	2	2	8	2	2
Valve Sites	40	4	2	5	7	2
Approx. no. of Landowners	500	150	100	300	140	150

Note 1 – excludes small offtake points. Some of the data presented in this table may be subject to change in the future as further technical developments are undertaken, and additional facilities are installed to provide upgraded service to users.

6.3 Transportation Distance

The transportation distance to be used in determining the charges for specific point-to-point services are based on the pipeline route distance as determined by EAPL and expressed to the nearest kilometre. A table of transportation distances for the current pipeline system configuration is set out in the table below.

Transportation Distances: Mainline & Regional Laterals (km)

MAINLINE			REGIONAL LATERALS	
Mainline Delivery Points and Lateral Offtake Points	**Distance from Moomba**	**Distance from Culcairn**	**Regional Lateral Delivery Points**	**Distance from Lateral Offtake**
Mainline			***Griffith Lateral***	
Bulla Park Ethane	578	674	Junee	6
Marsden (West Wyalong)	942	310	Coolamon	40
Marsden (Central West Pipeline)	942	310	Ganmain	56
Boorowa	1077	263	Narranderra	104
Blakney Creek (Yass)	1114	300	Rockdale	116
Goulburn	1185	370	Leeton	125
Marulan	1207	393	Griffith	179
Sally's Corner	1231	417		
Moss Vale	1246	432		
Bowral	1256	442	***Northern Lateral***	
Bargo	1284	470		
Wilton	1299	485	Cowra	58
			Blayney	125
Canberra (Watson)	1189	374	Millthorpe	121
			Orange	138
Young (township)	1046	206	Bathurst	161
Wallendbeen (Temora)	1072	180	Oberon	201
Cootamundra	1090	167	Wallerawang	204
Illabo	1125	127	Lithgow	212
Wagga Wagga	1164	88		
Uranquinty	1192	60		
Henty	1236	16		
Holbrook (Culcairn township)	1252	0		
Culcairn (Interconnect)	1252	-		
Lateral Offtake Points				
Griffith Lateral (at Burnt Creek)	1138	114		
Northern Lateral (Young junction)	1033	219		

6.4 System Capacity

There have been no changes that would affect system capacity for the MSP since the 1999 Access Arrangement was submitted.

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

Another important factor for the MSP is the direction of net physical flow of gas in the Young to Culcairn segment of the pipeline, linking MSP with the GasNet Principal Transmission System (PTS).

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 MSP currently has two mainline compressor stations located at Bulla Park and Young, and a smaller unit (the Young-Lithgow, or YL Compressor) on the Northern Lateral. Existing MSP capacity could be almost doubled by expanding the number of mainline compressor stations to a maximum of eight (before pipeline looping is required).

It is EAPL's clear intention to transport as much gas as is commercially prudent. To determine the capacity of the MSP system, a series of complex flow studies was undertaken based on a set of base assumptions about the relevant variables.

Each current Delivery Point is assumed to receive a daily quantity of gas based on annual load projections that will follow a predicted flow profile on a weekly basis. A transient model is used to determine the quantity of gas that can be supplied through Wilton and all other Delivery Points while still maintaining minimum contracted delivery pressures. The declared capacity figure is determined from the total of all accumulated deliveries on a peak day. The dynamic or transient capacity, so determined, exceeds the steady state capacity (ie: for constant delivery and receipt flow rates) as the capacity is declared as a peak day MDQ within a weekly cycle based on historical profiles of demand in NSW/ACT. As such EAPL bears the risk if the weekly profile in practice is different to the assumed historical profile.

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.

The current capacity of the total MSP system (assuming supply from Moomba only) is rated at 470 TJ/d based on a number of major assumptions including a minimum receipt pressure from the Moomba Gas Plant, weekly delivery point load profiles and expected Interconnect flows. In its existing configuration, the MSP's historical peak day delivery was approximately 459 TJ in July 2000.

The Canberra Lateral capacity is rated at 45 TJ/d. From time to time, MSP deliveries have exceeded 50 TJ/d, but this is not achievable on a steady basis.

The Northern Lateral is capable in its current configuration (ie with use of both Mainline and Lateral compressors at Young) of transporting approximately 16 TJ/d in addition to Lithgow and approximately 4 TJ/d on the Oberon spur for a total of approximately 20 TJ/d. The Oberon spur itself could transport up to 8.2 TJ/d, depending on demand in other centres served by the Northern Lateral (notably Bathurst, Orange, Lithgow and Blayney). EAPL anticipates there may be a need for expansion of the Northern Lateral by way of additional compression for the winter of 2004, but that it will definitely be required by 2006.

The Griffith Lateral has an existing capacity of approximately 10.8 TJ/d.

The Interconnect, completed in 1998, is a bi-directional flow pipeline. In comparison to the pipeline diameters on either side of it, the Interconnect is larger in diameter, as it was intentionally oversized to accommodate higher potentially higher future gas flows.

The physical capacity of the Interconnect is nominally 52 TJ/d southbound (this is in addition to the capacity on the Wagga Lateral segment and the Griffith Lateral) and between 17 TJ/d (winter) and 30 TJ/d (summer) northbound. The southbound capacity is greater than the northbound capacity due to the proximity and larger size of compression on the MSP system (at Young) compared to that of the GasNet PTS compression (at Wollert).

It should be noted that the northbound capacity is limited by constraints on the GasNet PTS system. That is, the Interconnect is able to receive more than 30 TJ/d, but the GasNet PTS is not able to supply it.

The existing capacity of the Interconnect in both directions would be significantly enhanced by the addition of a compressor station at Uranquinty (near Wagga Wagga). With further compression on the GasNet PTS, particularly from Wollert to Barnawartha, the northbound capacity could be increased to roughly 110 TJ/d and with additional looping of the up and downstream segments of the Interconnect, at least 240 TJ/d.

Since the commissioning of the EGP in September 2000, considerable firm capacity exists on the MSP system in its current configuration. Moreover, a large amount of Developable Capacity exists.

6.5 Delivery Points and Pressures

A list of major Delivery Points and their respective Minimum Delivery Pressures is shown in the table below.

Delivery Points & Minimum Delivery Pressures

Pipeline Segment	Delivery Point (Note 1)	Minimum Delivery Pressure (kPag)
Moomba Wilton Pipeline	Marsden Goulburn Marulan Moss Vale Bowral Wilton	3500 1750 1750 1750 1750 3800
Canberra Lateral	Canberra	1205
Northern Lateral	Cowra Blayney Orange Bathurst Oberon Lithgow	1750 1750 1750 1750 1750 1750
Wagga Lateral	Young (township) Cootamundra Illabo Bomen (Wagga Wagga)	1750 1750 1750 1750
Griffith Lateral	Junee Coolamon Narrandera Rockdale (Feedlot) Leeton Murrami Griffith	1750 1750 1750 1750 1750 1750 1750
Interconnect	Uranquinty (Wagga Wagga) Holbrook/Henty Culcairn	1750 1750 3000

Note 1 - small take-off points (STP) are not shown, but generally have a minimum delivery pressure of 1750 kPa Gauge.

6.6 Historical Average and Peak Day Delivery Throughput

The following table contains average and peak day throughputs for major Delivery Points on the MSP.

Average And Peak Day Throughputs (GJ/d)
(Actual 2003)

Major Delivery Point[2]	Average daily throughput	Peak day throughput
Marsden	2,018	5,261
Goulburn	1,821	[redacted]
Marulan	2,812	[redacted]
Moss Vale	599	[redacted]
Bowral	2,172	[redacted]
Wilton	[redacted]	[redacted]
Canberra	[redacted]	[redacted]
Cowra	352	859
Blayney	608	1,493
Orange	1,888	4,984
Bathurst	2,993	5,914
Oberon	1,899	3,026
Lithgow	729	1,946
Griffith Lateral[1]	2,942	6,725
Young (township)	683	[redacted]
Cootamundra	394	[redacted]
Illabo	1,325	[redacted]
Bomen (Wagga Wagga)	2,516	[redacted]
Uranquinty (Wagga Wagga)	1,669	[redacted]
Culcairn (southbound)	6,722	[redacted]

Note:

1. The Griffith Lateral is metered at the inlet. EAPL does not have meter readings for the Delivery Points on the lateral.
2. Due to their very small throughputs, small take-off points (STP's) are not shown. Total annual throughput at all STP's is less than 500 TJ/a, or less than 1400 GJ/d across 10 STPs.

6.7 Forecast Throughput

Section 8.2(e) of the Code requires that forecasts used in determination of the Reference Tariffs represent best estimates arrived at on a reasonable basis.

EAPL submitted revised MSP throughput forecasts to the Commission following an announcement by AGL (the major shipper on the MSP) in December 2002 that it had entered into new long term gas supply arrangements. These arrangements include a substantial quantity of gas being contracted from the Gippsland Basin in Victoria, and that AGL had also contracted to utilise the EGP to transport a portion of this supply.

As AGL has historically been the major user on the MSP, EAPL believes a significant change in expected MSP throughput is likely to occur. In addition, the magnitude and timing of anticipated gas-fired electricity generation continues to change as State and Federal Government policy develops in relation to greenhouse gas emissions. There have also been additions to reserves in northern and south eastern Australia, changing the likely supply sourcing options for the south eastern Australia over the next 20 to 30 years.

These and other changes in the energy market environment made it essential that EAPL revise its forecast of MSP throughput for the current Access Arrangement Period and the period to 2023.

The changes to the MSP forecast, both within the Access Arrangement Period and in the 15 year period afterward (ie 2009 to 2023) are significant for calculation of the tariffs during the Access Arrangement Period as a result of using the NPV methodology.

EAPL has had the MSP forecast independently reviewed by ACIL Tasman Consulting, and made additional amendments based on ACIL Tasman's recommendations. On that basis, ACIL Tasman concluded:

> *Taken as a whole, ACIL Tasman concludes that the EAPL forecast of gas flows through the MSP is based on sound methodology. Further, as the estimates fall within the bounds of the ACIL Tasman scenarios of future gas supply developed in this report, the EAPL forecast flows on the MSP are considered to be 'reasonable best estimates', reflecting a balanced outlook for supply of gas from northern and southern basins.*

6.7.1 Sources and Assumptions

In determining its forecasts of future throughput, EAPL referred primarily to the following sources:

- Historical MSP throughput.
- An ABARE forecast of NSW/ACT gas demand (March 2003).
- Public statements by EGP, Sydney Gas, MSP shippers and producers.
- Discussions with current and prospective shippers.

- National Electricity Market Management Company (NEMMCO) – Statement of Opportunities (SOO 2002).
- Ministry of Energy and Utilities (NSW) – Statement of System Opportunities 2002 (SSO).

The latter two documents were used to forecast gas-fired electricity generation growth in NSW/ACT

6.7.2 Methodology

In forecasting expected MSP throughput for the MSP, EAPL undertook the following steps:

(a) define the market area as NSW and the ACT, and Victoria via the Interconnect;

(b) determine the base total demand by reference to actual MSP throughput prior to the commencement of the EGP's operation (when MSP transported 100% of the NSW/ACT gas demand);

(c) apply ABARE forecast demand growth rates to the base conventional gas market demand (the residential, commercial and industrial markets);

(d) apply the MEU's SSO to derive the forecast demand resulting from gas-fired electricity generation to 2020;

(e) forecast and deduct the estimated coal seam methane supplies from the NSW/ACT total demand figure;

(f) forecast EGP's share of future conventional and gas-fired electricity generation related demand for NSW/ACT;

(g) allocate the remainder of the NSW/ACT demand to the MSP;

(h) allocate the MSP share of total NSW/ACT demand to the two MSP receipt points: Moomba and Culcairn (the Interconnect); and

(i) forecast additional MSP deliveries to Victoria through the Interconnect (from Moomba to Culcairn).

6.7.3 Assumptions

Significant assumptions underlying the EAPL forecasts are as follows:

(a) The base NSW/ACT conventional demand is represented by actual MSP throughput in 1999/00 (as opposed to ABARE's estimate of demand in that year which EAPL regards as too high);

(b) ABARE growth rates for conventional demand are applied to EAPL's base conventional demand from 2000 to 2020;

(c) Coal seam methane in NSW/ACT was assumed to be supplied entirely by Sydney Gas Limited from the Sydney Basin, at somewhat less than figures in Sydney Gas' public statements;

(d) Existing gas demand for electricity generation (Sithe Energies cogeneration facility at Smithfield) is supplied from the EGP;

(e) Large scale gas-fired electricity generation is not viable in NSW/ACT until 2008;

(f) Thereafter, incremental demand from additional gas-fired generation facilities is shared between the MSP and EGP (the total gas-fired electricity generation estimate is for 1,125 MW consuming approximately 53PJ/a by 2018);

(g) Cogeneration demand is less than that assumed in EAPL's 1999 forecasts as it is limited to specialised smaller applications, and is included in industrial demand (specifically large scale projects at Botany and Kurnell are unlikely to proceed);

(h) Forecast EGP throughput is increased by EAPL's estimates of increasing AGL supply for NSW/ACT from Gippsland (based on the AGL December 2002 announcement);

(i) Remaining conventional demand growth is shared by EGP and the MSP;

(j) Interconnect flows are revised to flow in a net physical northbound direction during and after the Access Arrangement Period. However, this will be bi-directional and will change from season to season depending on market conditions;

(k) Forecast throughput to all MSP delivery points other than Wilton, Canberra and Culcairn (in both south and northbound directions) remained the same as used for the April 2002 Access Arrangement; and

(l) In the short to medium term, there will be no northern supply (Timor or PNG). However, in the longer term gas will be delivered via Moomba from Queensland (ie including coal seam methane and northern supply).

6.7.4 Independent Expert Review

In its review of EAPL's forecast of MSP throughput, ACIL Tasman has adopted a rigorous econometric methodology in deriving its own forecast as a basis for its review. Key elements of ACIL Tasman's forecast methodology include:

(a) use of ABARE forecasts for conventional demand;

(b) use of PowerMark (its proprietary model) to forecast the gas requirements for electricity demand in NSW/ACT;

(c) use of GasMark (its proprietary econometric modelling tool) to forecast sourcing of total gas demand including supply basins and therefore pipeline transportation routes; and

(d) development of two bounding supply scenarios which reflect a range of exploration and production possibilities in northern and southeast Australian supply basins.

In spite of the fact that EAPL and ACIL Tasman utilised methodologies which differed in a number of respects in providing their respective forecasts, the key ACIL Tasman conclusions from comparing the forecasts were:

(a) estimates of conventional demand for NSW/ACT were the substantially the same over the period;

(b) additional large scale gas-fired electricity generation would not be economic in NSW until 2008, in spite of the mandatory NSW greenhouse benchmark scheme and the Commonwealth's Mandatory Renewal Energy Target (MRET) Scheme (the ACIL Tasman and EAPL forecasts differ only slightly in the year-on-year growth in gas fired electricity demand thereafter);

(c) expectations for supply of coal seam methane were broadly consistent; however, ACIL Tasman adopted a more optimistic view of coal seam methane supply; and

(d) the EAPL allocation of the remaining market (after coal seam methane) between EGP and MSP for both conventional and gas-fired electricity demand landed well within the range of possible supply scenarios.

6.7.5 Forecast Results

The following table sets out EAPL's forecast of total NSW/ACT demand and the MSP forecast aggregate throughput for the for the Access Arrangement Period.

Forecast MSP Throughput
(PJ/a)

Period Ending 30 June	2003	2004	2005	2006	2007	2008
NSW/ACT Demand	**118.7**	**121.3**	**123.5**	**126.5**	**130.1**	**136.5**
MSP Aggregate Throughput	**95.5**	**95.4**	**92.4**	**93.6**	**93.2**	**90.0**

Note: (1) The MSP has lost significant load since the startup of the EGP (Sept 2000).
(2) Projections in this revised Access Arrangement Information are based on a number of assumptions. Although EAPL regards these assumptions as appropriate to base the projection on at the present time, EAPL cannot and does not make any representation or warranty as to the accuracy of the projections.

Forecast Total Annual Volume By Segment
(PJ/a)

	2003	2004	2005	2006	2007	2008
Moomba Wilton Pipeline	**77.1**	**75.8**	**72.4**	**72.3**	**67.6**	**62.6**
Canberra Lateral	**6.7**	**6.9**	**7.1**	**7.3**	**7.5**	**7.8**
Northern Lateral	**3.3**	**3.4**	**3.5**	**3.6**	**3.7**	**3.8**
Wagga Lateral	**2.7**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**
Griffith Lateral	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**
Interconnect – Receipt	**3.0**	**4.0**	**5.0**	**6.0**	**7.0**	**7.4**
Interconnect – Delivery	**1.4**	**1.2**	**0.2**	**0.2**	**3.0**	**4.0**

Note: Projections in this revised Access Arrangement Information are based on a number of assumptions. Although EAPL regards these assumptions as appropriate to base the projection on at the present time, EAPL cannot and does not make any representation or warranty as to the accuracy of the projections.

6.8 Volume-Distance Data for use in determining tariffs

The table following sets out the Volume-Distance data derived from the MSP forecast quantities to be transported during the Access Arrangement Period on each segment of the MSP using the pipeline route distances as provided in Section 6.3.

On most Contract Carriage pipelines, including the MSP, a shipper is required to contract for or ‘reserve’ capacity to meet its end customers’ peak day deliveries, and the pipeline’s revenue is primarily based on the aggregate of its contracted daily capacity. This is referred to as the MDQ in transportation agreements. Accordingly, the Capacity Charge component of a Reference Tariff is determined using the estimated contracted daily capacity required by all shippers, and not the expected annual throughput for each delivery point. Contracted daily capacity is estimated by adjusting the forecast annual flows (average daily) by an estimated load factor, defined in this case as the peak day deliveries over the average daily deliveries.

Since the loss of market to the EGP, the MSP has had a system wide average load factor. This load factor is forecast to remain consistent during the Access Arrangement Period.

To determine the Capacity Charge component of the MSP Reference Tariff, EAPL has used a Capacity-Distance measure. The Capacity-Distance measure for a Delivery Point is determined as the estimate of daily capacity required at the Deliver Points, multiplied by the pipeline distance from the Receipt Point to that Delivery Point. This is referred to as the “TJ-km” (or “GJ-km”). The result is a Capacity Charge component that can be expressed in dollars per unit of energy per km ($/GJ/km), and it applies to each GJ of MDQ under contract.

To determine the Throughput Charge component of the MSP Reference Tariffs EAPL has used a Throughput-Distance measure. The Throughput-Distance measure is related to actual annual throughput and therefore does not require a load factor adjustment. The Throughput Charge component is also expressed in $/GJ/km and applies to each GJ of actual throughput.

MSP Capacity And Throughput Distances (2003 to 2008)

Capacity Distance (TJ/d * km)

Year Ending 30 June:	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Mainline:	463,246	457,616	437,465	438,850	427,942	407,168
Regional Laterals:	22,624	23,239	23,871	24,521	25,189	25,876

Throughput Distance (PJ/a * km)

Year Ending 30 June:	2003	2004	2005	2006	2007	2008
Mainline:	112,723	111,353	106,450	106,787	104,133	99,077
Regional Laterals:	5,505	5,655	5,809	5,967	6,129	6,296

Note: (1) In calculating tariffs Mainline tariffs the Capacity-Distance measure uses the distance from the applicable Moomba or Culcairn Receipt Point to all Mainline Delivery Points. The Regional Lateral Capacity-Distance measure uses the distance from the applicable Moomba or Culcairn Receipt Point to all Regional Lateral Delivery Points.
(2) In the bi-directional Young to Culcairn segment the Capacity-Distance measure has been reduced to account for backhaul credits where applicable, refer to Section 6.12 of the revised Access Arrangement.

6.9 System Load Profile by Month

The system load profile for each of the Mainline and Regional Laterals, expressed as the percentage of each month's throughput to the annual total, is contained in the following table.

	Monthly % of Annual Throughput (2002/03)	
	Mainline	**Regional Laterals**
July	11.30	13.61
August	10.48	11.89
September	9.06	9.32
October	8.01	7.32
November	7.24	5.86
December	6.84	4.88
January	6.33	5.06
February	6.44	5.72
March	7.45	6.91
April	7.63	7.40
May	9.46	10.15
June	9.76	11.88
Total	100.0	100.0

6.10 Number of Customers

As of 1 July 2003, the total number of shippers using the MSP is five.

7. EFFICIENT COSTS AND PERFORMANCE MEASURES FOR PIPELINES

7.1 Objective of Demonstrating Efficient Costs

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[16]. Efficient costs are defined to be 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[17].

7.2 Issues Relating to Performance Measures and Benchmarking of Transmission Pipelines

Despite the increasing availability of information for benchmarking of Australian pipelines as a result of the completion of a number of Access Arrangement reviews, there continue to be challenges in deriving meaningful comparisons of the performance of individual pipelines in the industry. Despite the increasing amount of data, the traditional difficulty of "normalising" pipelines to yield meaningful comparisons, (due to extremely diverse characteristics of pipelines such as size, length, geography and topography of location, operational characteristics etc) remains.

It is also important to recognise the limitations of benchmarking. It is not a precise science because of the multitude of variables that affect costs, and can only provide a broad indication of whether a particular pipeline's costs lie within the "ballpark" of costs that are efficient.

Despite the availability of new information there persists an inconsistent approach to benchmarking of pipeline operating costs. KPIs must have a sound basis to be meaningful. In order to derive a meaningful set of KPIs it is necessary to have both an understanding of:

- the pipeline industry; and
- the cost drivers that will lead to meaningful KPIs.

7.2.1 Industry Experience

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

[16] Section 8.1(a).

[17] Section 8.37.

under "average" conditions to be incurred in operating pipelines. These are set out in the table below.

Indicative Total Pipeline Operating Expenses as a Percentage of Asset Replacement Cost

Asset	Average	Large Pipeline	Small Pipeline
Pipeline	2.0%	1.5%	2.5%

Asset	Average	Multiple Units	Single Unit
Compressors[18] (gas turbines)	6.0%	5.0%	7.0%

7.2.2 Pipeline Industry Cost Drivers

While there are a broad number of factors that affect costs, the primary operating cost driver for pipelines is the length of a pipeline.

Other significant secondary cost drivers are:

- the number/size of compressor stations; and
- the number/size of offtake stations.

A pipeline's size (ie diameter) has at most some minor secondary or tertiary impact on operating costs. Pipeline size is a reflection of pipeline capacity or throughput. Generally the replacement cost of a pipeline (or as a proxy ORC) provides an index that incorporates length, the impact of compressor and offtake stations and diameter. Such items as throughput and pipeline capacity are not significant operating cost drivers. Measures which use these are generally invalid. As a consequence the best partial factor productivity indicators use either pipeline length or replacement cost (or if not available ORC).

Accordingly the generally accepted KPIs used by industry are:

- $operating cost/km length
- $operating cost/$ORC.

In the Final Decision on the Moomba-Adelaide Pipeline the Commission, in referring to the $operating cost/$ORC measure, noted that:

> *Typically this ranges from 2 percent for an uncompressed pipeline to 5 percent for a fully compressed pipeline.*

The Commission also considered the second measure ($operating expenditure per km) in the Moomba-Adelaide Pipeline Final Decision.

[18] Excluding fuel gas cost.

Measures which are misleading and should not be used are:

- $ operating cost / TJ annual throughput
- $ operating cost / km length / TJ annual throughput

7.3 Key Performance Indicators and Benchmarks

The following benchmarking exercises provide a sound basis for the assessment of operating costs for the MSP.

7.3.1 Total Operating Cost – Comparison with Australian Pipelines

As discussed above two benchmarks are considered in the pipeline industry as providing meaningful benchmarks of the level of operating costs:

- Operating cost as a percentage of pipeline capital (replacement) cost.
- Operating cost per km of pipeline length.

Operating cost as a percentage of ORC

The overall MSP ratio of 2.2 percent is consistent with the Commission's expected ratio for a partially compressed pipeline, and is in line with pipelines of similar size, terrain and levels of compression. The ratio for the Mainline is 2.2 percent and for the Regional Laterals is 2.2 percent.

Operating cost per km

This ratio at $11,400 per km for the overall MSP is also within the range accepted for similar pipelines. The ratio for the Mainline is $13,574 per km and for the Regional Laterals is $3,986 per km.

The table below compares the values for the MSP for both measures against the major Australian pipelines, based on the operating cost values approved by regulators under Final Decisions, or Draft Decisions where there is no Final Decision.

On both measures the operating cost for the MSP is well within the range of variables accepted by regulators.

Benchmarking O&M Costs for Australian Pipelines
(real 2001 dollars)

	EAPL MSP		**Epic MAP**		**GasNet**		**GGT**		**Epic DBNGP**		**NT Gas ADP**	
	% ORC	$000 /km	% ORC	$000 /km	% ORC	$000 /km	% ORC	$000 /km	% ORC	$000 /km	% ORC	$000/ km
2000							2.3%	7.5	1.7%	16.8		
2001			2.4%	14.4			2.2%	7.2	1.6%	16.4		
2002			2.3%	13.8			2.2%	7.2	1.8%	18.5	1.7%	3.7
2003	2.2%	11.3	2.3%	13.9	3.6%	14.6	2.2%	7.2	1.8%	18.2	1.7%	3.7
2004	2.2%	11.5	2.3%	13.8	2.5%	9.9	2.4%	7.8	1.8%	17.8	1.7%	3.7
2005	2.2%	11.4	2.3%	13.8	2.4%	9.6					2.0%	4.4
2006	2.2%	11.4			2.5%	10.1					1.7%	3.7
2007	2.2%	11.4			2.5%	10.1						
2008	2.2%	11.4										

7.3.2 Total Operating Cost – Comparison with GasNet

The most appropriate comparison or benchmark pipeline for the costs of the MSP is the GasNet Primary Transmission System (PTS). The PTS has a comparable number of offtakes to the MSP, however it is considerably shorter in length and does not suffer many of the geographic access issues (associated with remote regions) that impact the MSP's cost structure. The total PTS costs are approximately $20 million compared with EAPL's total operating costs of $23 million. However, the MSP includes significant activities as part of its transportation services that are undertaken by VENCorp for the PTS.

To conduct a meaningful comparison of the PTS's costs with the MSP, the PTS costs should also include the costs of VENCorp or at least a portion of them. If only 50% of VENCorp charges (to be conservative) are added to the PTS's costs, the total costs in 2003 are approximately $30 million compared with EAPL's total operating costs of approximately $23 million. The efficient costs of the PTS (as determined by the Commission) adjusted to include appropriate VENCorp costs are therefore an important benchmark for "market testing" or assessing the operating costs of the MSP.

In light of the Commissions recognition that GasNet and VENCorp's operating expenditures are efficient, it is EAPL's view that for the Commission to remain consistent in its decisions, it would be bound to approve EAPL operating expenditure for the MSP as meeting the requirements of the Code.

ATTACHMENT 1

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

Category in Access Code	Reference in the Access Arrangement Information
Category 1: Information regarding Access & Pricing Principles	
Tariff determination methodology.	2.3
Cost Allocation approach.	2.5
Incentive structure.	2.6
Category 2: Information regarding Capital Costs	
Asset values for each pricing zone, service or category of asset.	3.1.6
Information as to asset valuation methodologies – historical cost or asset valuation.	3.1.1, 3.1.2, 3.1.3, 3.1.4, 3.1.5
Assumptions on life of asset for depreciation.	3.2
Depreciation.	3.2
Backended depreciation.	3.2.1
Committed capital works and capital investment.	3.3
Description of nature and justification for planned capital investment.	3.3.1
Rates of return – on equity and on debt.	3.4
Capital Structure – debt/equity split assumed.	3.4.2
Equity returns assumed – variables used in derivation.	3.4.4
Debt costs assumed – variables used in Derivation.	3.4.4
Category 3: Information regarding Operations and Maintenance Costs	
Fixed versus variable costs.	4.3
Cost allocation between zones, services or categories of asset & between regulated and unregulated.	4.5
Wages & Salaries – by pricing zone, service or asset category.	4.5
Cost of services by other including rental equipment.	4.5
Gas used in operations – unaccounted for gas to be separated from compressor fuel.	4.5
Materials and supply.	4.5
Property Taxes.	4.5
Category 4: Information on Overheads & Marketing Costs	
Total service provider costs at corporate level	4.2
Allocation of costs between regulated and unregulated segments.	4.4
Allocation of costs between particular zones, services or categories of asset.	4.5

Category in Access Code	Reference in Access Arrangement Information
Category 5: Information regarding System Capacity & Volume assumptions	
Description of system capabilities	6.2, 6.4
Map of piping system – pipe sizes, distances and maximum delivery capability.	6.2
Average daily and peak demand at "city gates" defined by volume and pressure.	6.2, 6.3, 6.5
Annual volume across each pricing zone, service or category of asset.	6.7.5
System load profile by month in each pricing zone, service or category of asset.	6.9
Total Number of customers in each pricing zone, service or category of asset.	6.10
Category 6: Information regarding Key Performance Indicators	
Industry KPIs used by The Service Provider to justify "reasonable incurred" costs.	7.3.1
Service provider's KPIs for each pricing zone, service or category of asset.	7.3.1