GasNet Australia Access Arrangement - Submission

Dated 27 March 2002

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Contents

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> ***NOTE:***
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> *This Submission will be lodged with the ACCC in March 2002 along with the draft GasNet Access Arrangement and the draft GasNet Access Arrangement Information. This Submission sets out GasNet's arguments in support of its draft Access Arrangement.*

1 Executive Summary

1.1 Background

The GNS is the primary transmission system for the delivery of gas throughout Victoria, transporting approximately 220 PJ of gas each year (over 95% of Victoria's gas demand). The GNS is owned by GasNet and operated by VENCorp (a State Government authority) as a "Market Carriage" pipeline under the MSO Rules.

In December 1998 the Commission approved the Access Arrangements lodged by GasNet (then TPA) and VENCorp governing access to the PTS and WTS up to 31 December 2002.

This Submission supports GasNet's proposed revisions to its Access Arrangements. These revisions will, subject to approval by the Commission, take effect on 1 January 2003.

There are two Service Providers (as defined in the Code) with respect to the GNS. GasNet is the owner of the GNS and is responsible for the maintenance of the GNS. VENCorp is the operator of the GNS under the Market Carriage system established by the MSO Rules.

This Submission deals only with the GasNet Access Arrangements. The proposed VENCorp Access Arrangement for the Second Access Arrangement Period is the subject of a separate submission by VENCorp.

1.2 Business as usual

GasNet's proposed revisions maintain most elements of the current Access Arrangements, which have been in operation for over three years. However, GasNet considers there is room to fine tune the Access Arrangements and proposes a number of changes, including the following.

(a) As a result of the interconnection between the WTS and the PTS, GasNet is proposing to merge both the PTS and WTS Access Arrangements. To this end, it has lodged with the Commission one draft Access Arrangement for the whole system (the GNS Access Arrangement) to apply in the Second Access Arrangement Period commencing on 1 January 2003.

(b) GasNet proposes to rectify a number of errors in the Capital Base referred to by the Commission in its Final Decision in 1998.

(c) GasNet proposes to include in its Capital Base the capital cost of the SWP, which was completed in 1999. These costs have been allocated to a stand-alone tariff applying to the SWP.

(d) Reflecting the diversity of supply points (and corresponding reduced risk of constraints) and participant concerns, GasNet proposes to alter the tariff parameters so that:

(i) all withdrawals are charged on a flat "anytime" rate (as opposed to the current "5-day peak" basis for Tariff-D customers and the winter volume charge for Tariff-V customers); and

(ii) injections are charged on a "10-day peak" basis (as opposed to the current "5-day peak" basis).

1.3 The Market Carriage System

GasNet and VENCorp operate under the unique Market Carriage system, which applies only in Victoria and, currently, only to the GNS. The Market Carriage system was implemented by the Victorian Government as part of the restructuring and privatisation of the Victorian gas industry in 1997 and 1998.

Market Carriage incorporates a number of important features that are different from a traditional contract carriage pipeline. In particular:

(a) shippers are not required to reserve capacity under long term take or pay contracts in order to ship the gas through the Market Carriage system (instead, tariffs are recovered via a pay-as-you-go system);

(b) subject to residual curtailment powers, VENCorp will accept all gas for delivery and rely instead on market signals to relieve potential constraints; and

(c) VENCorp operates a spot market into which participants can bid gas supply and through which all gas imbalances are taken to be bought or sold.

This has a number of significant implications for GasNet. For example, unlike other pipeline owners in Australia, GasNet does not enjoy the benefit of long-term take or pay contracts and the associated revenue certainties that these bring. In addition, the pay-as-you-go tariff system means that GasNet is subject to increased gas demand volume risk, which is extremely sensitive to circumstances outside GasNet's control such as weather patterns and expansions and contractions in the economy. These factors contributed to a significant revenue shortfall during the First Access Arrangement Period, in relation to which GasNet estimates that it will suffer an aggregate revenue shortfall of $19.3 million.

1.4 Determining the Reference Tariffs

GasNet proposes to retain the Cost of Service Methodology for revenue determination, which is the methodology used in the current PTS and WTS Access Arrangements. Under this approach, the revenue to be generated from the sales (or forecast sales) of all services over the regulatory period is, subject to the Code, equal to the costs (or forecast costs) of providing all the services. In addition, GasNet proposes to retain the existing "price path" form of regulation.

In the course of the First Access Arrangement Period GasNet has suffered a revenue shortfall which is anticipated to exceed $19.3 million by the end of 2002. This is due primarily to the fact that actual volumes have been significantly lower than forecast volumes and, under GasNet's price path form of regulation, the current tariffs have proven to be too low to provide the approved regulated revenue.

GasNet has sought to apply the Reference Tariff Principles set out in section 8 of the Code in a way that recognises the fundamental importance of the criteria set out in section 2.24 of the Code. In particular, GasNet has sought to recognise the requirement that the Commission must take into account GasNet's legitimate business interests and investment, the public interest and the interests of Users and Prospective Users.

The proposed average tariffs for the Second Access Arrangement Period will increase by 11%[1] in real terms from the 2002 published tariffs to the discounted weighted average tariff to apply over 2003 to 2007. This increase is due primarily to:

(a) an increase in the underlying WACC parameters;

(b) rectification of errors in the Capital Base; and

(c) the carry-forward of the accumulated K-factor carryover relating to the First Access Arrangement Period.

Transmission charges account for approximately 5-10% of the total cost to the end user. A 10% increase in transmission tariffs equates to an approximate tariff increase of 1% to end users.

1.5 Establishing the Capital Base

1.5.1 *Rolling forward the Capital Base*

In order to establish the Capital Base at the start of the First Access Arrangement Period, GasNet (then TPA) commissioned GHD to provide a valuation of the transmission assets covering both the WTS and PTS. GHD established a value for the regulated assets based on the ODRC methodology, which was accepted by the Commission. However, for the purposes of tariff calculation, certain assets (including easements) were excluded from the Capital Base (totalling approximately $52 million). In addition, the Capital Base identified by the Commission in the Final Decision ($363.7 million) incorrectly omitted the Murray Valley pipeline (which had only just been completed) and overstated the net result by $5.7 million.

For the purposes of calculating the Capital Base for the commencement of the Second Access Arrangement Period, GasNet has rolled forward the rectified Capital Base to reflect only the assets identified in the GHD valuation.

[1] This excludes the SWP which is charged on a stand alone basis.

1.5.2 *New Facilities Investment*

In 1998 the Commission approved various items of forecast capital expenditure for the First Access Arrangement Period totalling $60.7 million.[2] GasNet has completed some of these projects, while it has not completed a number of others, choosing instead to achieve its service obligations under the Service Envelope Agreement by implementing alternative capital projects. These alternative projects were undertaken because they were assessed to deliver a better optimised result either as a result of a cost/capacity trade off, or the ability to provide the capacity within the required timetable. In addition, GasNet has completed a number of other projects that were not contained in the forecast capital expenditure. The actual capital expenditure incurred by GasNet in the First Access Arrangement Period in connection with the PTS and WTS was $199.6 million.

A portion of this capital expenditure ($40.4 million) relating to the Interconnect Pipeline has already been rolled into the Capital Base. GasNet proposes to include the remaining capital expenditure ($102.1 million) in its Capital Base, except amounts in relation to the Bulla Park and Young compressor stations ($47.7 million), and amounts relating to the accelerated construction costs for the Interconnect Assets and SWP.

1.5.3 *Depreciation*

GasNet applied the current cost accounting (CCA) framework and a post tax real rate of return for establishing target revenues for the First Access Arrangement Period.

As a result of the differences between the forecast and actual capital expenditure, the actual depreciation for the First Access Arrangement Period is different from the forecast depreciation. For the purpose of calculating the Capital Base for the commencement of the Second Access Arrangement Period, GasNet has used the forecast depreciation adjusted for actual inflation, rather than the actual depreciation.

1.5.4 *Redundant capital*

GasNet has identified one redundant asset, being the North Paaratte Odorant Station, which has been excluded from the Capital Base. Under section 8.28 of the Code this may be reinstated at a later date if it subsequently contributes to the GNS. In addition, GasNet has disposed of a number of assets including land and vehicles. The Capital Base has been adjusted to reflect these disposals.

1.5.5 *Inflation*

As required by section 8.9 of the Code, GasNet has adjusted the Capital Base for inflation. Consistent with the real rate of return tariff methodology

[2] However, the forecast capital expenditure used by GasNet for tariff calculation purposes was $57.7 million. The difference between the forecast approved by the Commission and the forecast used for tariff calculation purposes represents the difference between the forecast cost of the Murray Valley Pipeline (approximately $18.7 million) and the actual cost ($15.7 million). The Murray Valley Pipeline was constructed prior to the commencement of the First Access Arrangement Period.

employed by GasNet, the Capital Base has been escalated each year in line with inflation. For 2002, GasNet has used a forecast annual inflation rate of 2.5% which is the mid point of the Reserve Bank target range.

1.5.6 *Summary of Capital Base*

Elements of Capital Base	Amount ($ million)
Capital base (as at 1 January 1998) identified by Commission	363.7
Adjustment for excluded assets and incorrect expression	35.8
Capital Base (1 January 1998)	399.5

Taking into account depreciation, inflation and capital expenditure since 1 January 1998, this gives an opening Capital Base at 1 January 2003 of $539.7 million.

1.6 Rate of return

GasNet's proposals in relation to the Rate of Return apply the well established WACC and CAPM methodologies employed by the Commission and other regulators to derive a real pre-tax WACC of 8.22%.

In relation to many of the parameters, GasNet proposes amounts that are generally within the range adopted by the Commission in recent regulatory decisions. However, in relation to a number of parameters (such as the equity beta) GasNet proposes marginally higher returns that better reflect the risk exposure of GasNet, including the pay-as-you-go Market Carriage system.

In addition, GasNet proposes a number of minor adjustments to the mechanics of the WACC estimation (for example, the selection of bond rates used to derive the risk free rate).

Finally, GasNet proposes a number of cash flow adjustments to reflect specific asymmetric risks that are not addressed by the CAPM.

1.7 Other capital elements

In calculating its revenue requirement, GasNet has, consistent with section 8.4 and 8.20 of the Code, included amounts in respect of forecast capital expenditure, depreciation and inflation.

GasNet has forecast recoverable capital expenditure of $87.0 million (nominal) for the Second Access Arrangement Period. The main items of capital expenditure are the partial looping of the Brooklyn-Corio pipeline between the Brooklyn compressor station and Paradise Road (in 2007), the Gooding compressor refurbishment and the Lurgi pipeline rehabilitation.

GasNet does not propose to deviate significantly from the depreciation schedule approved by the Commission for the First Access Arrangement Period, with the exception of the SWP. However, consistent with section 8.33(c) of the Code, GasNet has reviewed the basis for the calculation of the economic lives of the assets in light of recent information on gas reserves, interstate exports and other relevant events.

As GasNet has adopted a real rate of return tariff methodology, the Reference Tariffs incorporate an escalation of the Capital Base each year, taking into account depreciation in the preceding year.

1.8 Non-capital costs

GasNet has included in the Transmission Tariffs calculation an allowance for forecast non-capital costs, which has been determined on the basis of GasNet's best estimates and in light of historic figures. GasNet has then compared these with relevant KPIs and benchmarks and, on this basis, submits that its proposals are reasonable and prudent.

1.9 Reference Tariff calculation

GasNet has calculated a Total Revenue based on its proposed Rate of Return, Capital Base, Depreciation and Non Capital Costs.

GasNet has then converted this Total Revenue into a proposed tariff path. In summary, GasNet has not made significant modifications to the current tariff design. This is because:

(a) the unique circumstances of the Victorian Market Carriage system constrain the ability to vary the tariff design principles significantly; and

(b) there are benefits in maintaining consistency in tariffs between periods.

However GasNet has addressed some anomalies in the original cost allocation procedures and proposes changes where the tariff can be considerably simplified without detriment to existing Users. In addition, GasNet has been approached by a number of market participants who have identified areas where a bypass pipeline would be more economical than the existing transmission tariff, which suggests that some aspects of the existing tariff design are not efficient.

1.10 Access policies, terms and conditions and review of access arrangement

1.10.1 *Allocation of responsibilities*

Consistent with section 10.2 of the Code, there has been an allocation of responsibilities between GasNet and VENCorp relating to the different elements of an Access Arrangement. Each of GasNet and VENCorp is responsible for the description of a Services Policy and Reference Tariffs. VENCorp is responsible for describing the terms and conditions of access, the capacity management policy, the trading policy and the queuing policy. GasNet is responsible for the Extensions/Expansions Policy.

1.10.2 *Services Policy*

As set out in the draft GasNet Access Arrangement, GasNet proposes to revise the form of its Services Policy to bring it into line with underlying commercial and regulatory arrangements. These revisions will have no substantive impact on Users shipping gas via the GNS.

The key elements of GasNet's proposal are as follows.

(a) As the GNS is a market carriage transmission system, Users and Prospective Users of the GNS are offered one Reference Service (or bundle of Reference Services), being the transportation of gas under the MSO Rules.

(b) VENCorp, as operator of the GNS under the MSO Rules and as the party whom Users contract for service, is responsible for the provision of the Reference Service.

(c) Although it is a "Service Provider" under the Code, GasNet does not, under the MSO Rules, provide gas transmission services directly to Users.

(d) For the purposes of Reference Tariff calculation, the Reference Service comprises two components:

  (i) the VENCorp Services, which VENCorp provides itself (these are dealt with in the VENCorp Access Arrangement); and

  (ii) the Transmission Service, being the benefit of the availability of the GNS. In order to provide this component, VENCorp relies on the Service Envelope Agreement with GasNet.

1.10.3 *Extensions/Expansions Policy*

GasNet is proposing revisions to its Extensions/Expansions Policy to make it consistent with the relevant provisions of the Code (including sections 8.16 to 8.19).

1.10.4 *Review and Expiry of Access Arrangement*

GasNet and VENCorp have agreed that Revision Commencement Date will be 1 January 2008.

2 Introduction

2.1 Purpose

GasNet has lodged with the Commission the draft GasNet Access Arrangement and draft GasNet AA Information in relation to the GNS to apply in the Second Access Arrangement Period commencing on 1 January 2003.

The purpose of this Submission is to provide a detailed explanation of the content of and principles underlying the proposed GasNet Access Arrangement and GasNet AA Information.

2.2 Two Service Providers

There are two Service Providers (as defined in the Code) with respect to the GNS:

(a) GasNet is the owner of the GNS and is responsible for the maintenance of the GNS; and

(b) VENCorp is the operator of the GNS under the Market Carriage regime established by the MSO Rules.

As a result, the GasNet Access Arrangement must be read in conjunction with the VENCorp Access Arrangement. In particular, as operator, VENCorp is responsible for the registration and coordination of Users of the GNS.

This Submission only deals with the GasNet Access Arrangement. The proposed VENCorp Access Arrangement is the subject of a separate submission by VENCorp.

2.3 Criteria for assessing an Access Arrangement

The key criteria for assessing revisions to an Access Arrangement are set out in section 2.24 of the Code.

Under section 2.46 of the Code, the Commission may approve proposed revisions to an Access Arrangement only if it is satisfied that the Access Arrangement as revised would contain the elements and satisfy the principles set out in sections 3.1–3.20 of the Code. Importantly section 2.46 also provides that the Commission must assess the satisfaction of the principles in sections 3.1 to 3.20 in such a way as to take into account the current Access Arrangement and the following key criteria in section 2.24.

(a) The 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 (or both) already using the Covered Pipeline.

(c) The operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline.

(d) The economically efficient operation of the Covered Pipeline.

(e) The public interest, including the public interest in having competition in markets (whether or not in Australia).

(f) The interests of Users and Prospective Users.

(g) Any other matters that the Commission considers are relevant.

GasNet submits that these criteria are of fundamental significance under the Code. By force of section 2.46, the overall context of the Code and the very nature of the criteria specified in section 2.24 of the Code, the Commission's determination with respect to the revisions to the GasNet Access Arrangements must give effect to the criteria in section 2.24 of the Code. In particular, to the extent that any other matters lie to be determined by the Commission (for example whether the Reference Tariffs comply with the principles in section 8 of the Code), those determinations must be made (and the principles applied) in a manner which is consistent with the fundamental importance of the criteria in section 2.24.

2.4 Supporting documents

GasNet's Submission comprises:

(a) this Submission document;

(b) the schedules listed in section 12; and

(c) the annexures listed in section 13.

A number of the annexures are provided on a confidential basis (as described in section 13) because they contain commercially sensitive information relating to GasNet or Users.

3 GasNet System

3.1 Description of GasNet System

GasNet's transmission network comprises approximately 1,930 km of pipelines. It serves a total consumption base of approximately 1.4 million residential consumers and approximately 43,000 industrial and commercial consumers throughout Victoria.

At the time the original access arrangements were submitted for approval to the Commission in 1997, GasNet's transmission assets consisted of two separate networks, the PTS and the WTS. However, as a result of the construction of the SWP, the WTS is now physically connected to the PTS. A map of the GNS is contained in Schedule 1.

3.2 Service Envelope Agreement

3.2.1 *Function*

GasNet and VENCorp are parties to the Service Envelope Agreement. For the duration of the Second Access Arrangement Period[3], the Service Envelope Agreement provides that:

(a) GasNet agrees to:

   (i) make available the entire GNS[4] to VENCorp; and

   (ii) provide a range of supporting services to VENCorp; and

(b) VENCorp agrees to:

   (i) operate the GNS in accordance with the MSO Rules; and

   (ii) have the direct legal relationship with Users regarding a range of issues, including payment of charges for transmission services.

As a result of the Service Envelope Agreement, VENCorp will have operational control of the entire GNS and will be able to determine the manner in which Users are able to obtain services provided by means of the GNS.

3.2.2 *Duration*

The Service Envelope Agreement commenced on 15 March 1999 and is due to expire on 11 December 2007. However, GasNet and VENCorp have agreed to extend the operation of the Service Envelope Agreement to 31 December 2007 to coincide with the proposed end of the Second Access Arrangement Period.

[3] See section 3.2.2 of this Submission.

[4] See section 3.2.3 of this Submission.

3.2.3 *Application to WTS*

Currently, the Service Envelope Agreement only applies to the PTS. However, GasNet and VENCorp have reached in principle agreement that, with effect from 1 January 2003, the Service Envelope Agreement will also apply to the WTS, subject to the following conditions being satisfied.

(a) The Commission approving the merging of the WTS and PTS to form the GNS, as contemplated by section 5.3 of this Submission.

(b) The termination of the WTS Agreement as contemplated by section 5.3.4 of this Submission.

For the purposes of this Submission, GasNet has assumed that the merger of the PTS and WTS will be approved and that the Service Envelope Agreement will apply to the whole of the GNS.

3.3 Market Carriage

Access to the GNS for Users is governed by the MSO Rules, which establish a Market Carriage regime for the transportation of gas. In order to obtain Access to the GNS, a User must register with VENCorp as a Market Participant under the MSO Rules.

A fuller description of the market carriage system, together with a justification of the market carriage arrangements, are set out in the VENCorp Access Arrangement documents.

3.4 Section 3.8 Permit

Section 3.8 of the Code provides that the Commission must not accept an Access Arrangement which states that the Covered Pipeline is a Market Carriage Pipeline unless the relevant Minister of each jurisdiction in which the pipeline is wholly or partly located has given a notice permitting the pipeline to be a Market Carriage Pipeline.

GasNet and VENCorp have:

(a) sent a joint letter to the Minister for Energy in Victoria formally requesting her consent to the continued operation of market carriage system in the section of the PTS located in Victoria and the application of market carriage on the WTS; and

(b) sent a joint letter to the Minister for Energy in New South Wales formally requesting his consent to the continued operation of the market carriage system in the section of the PTS located in New South Wales (ie the Interconnect Assets).

Both Ministers have responded to the letter and formally provided their consent. A copy of the Ministers' letter of consent has been provided to the Commission.

4 Determining the Reference Tariffs

4.1 Summary of GasNet's Proposals

4.1.1 *Methodology*

GasNet proposes to retain the Cost of Service Methodology for revenue determination, which is the methodology used in the current PTS and WTS Access Arrangements. Under this approach, the revenue to be generated from the sales (or forecast sales) of all services over the regulatory period is, subject to the Code, equal to the costs (or forecast costs) of providing all the services. In addition, GasNet proposes to retain the existing "price path" form of regulation.

4.1.2 *Framework*

For the purposes of this Submission, GasNet has adopted a framework similar to that used by the Commission in recent decisions and structured its proposals in the following way.

(a) Establishing the Capital Base at the commencement of the Second Access Arrangement Period (see section 5 of this Submission).

(b) Setting an appropriate Rate of Return on the value of the Capital Base (see section 6 of this Submission).

(c) Calculating the depreciation of the Capital Base and other capital events over the Second Access Arrangement Period (see section 7 of this Submission).

(d) Calculating the forecast non-capital costs incurred in providing the services provided by the Covered Pipeline (see section 8 of this Submission).

(e) Calculating the Total Revenue and the Reference Tariffs (see section 9 of this Submission).

4.1.3 *Principles*

Through all of these items, GasNet has sought to apply the Reference Tariff Principles set out in section 8 of the Code in a way that recognises the fundamental importance of the criteria set out in section 2.24 of the Code. In particular, GasNet has sought to recognise the requirement that the Commission must take into account GasNet's legitimate business interests and investment, the public interest and the interests of Users and Prospective Users.

The proposed average tariffs for the Second Access Arrangement Period will increase by 11% in real terms from the 2002 published tariffs to the discounted weighted average tariff to apply over 2003 to 2007.

4.2 Code requirements

4.2.1 *Access Arrangements*

Section 3.4 of the Code requires the Regulator to be satisfied that the Access Arrangement and any Reference Tariff to be included in the Access Arrangement comply with the Reference Tariff principles described in section 8 of the Code.

Section 3.5 of the Code requires the Access Arrangement to include a policy describing the principles that are to be used to determine a Reference Tariff. The Reference Tariff Policy must, in the regulator's opinion, comply with the Reference Tariff objectives set out in section 8 of the Code.

4.2.2 *Section 8.1 of the Code*

The Reference Tariff Policy and all the Reference Tariffs should be designed to achieve the objectives set out in section 8.1 of the Code. Those objectives are:

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

(b) replicating the outcome of a competitive market;

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

(d) not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries;

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

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

To the extent that these objectives may conflict in their application, the Commission may determine how they can best be reconciled, or which of them should prevail.

4.2.3 *Section 8.2 of the Code*

Section 8.2 of the Code provides that, in determining whether to approve the Reference Tariffs and the Reference Tariff Policy, the Commission must be satisfied that:

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

(b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to recover is calculated consistently with the principles contained in section 8 of the Code;

(c) a Reference Tariff is designed so that the portion of Total Revenue to be recovered from a Reference Service is recovered from Users consistently with the principles contained in section 8 of the Code;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the relevant regulator considers appropriate and that such Incentive Mechanisms are consistent with the principles contained in section 8 of the Code; and

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

4.2.4 *Overarching principles*

However, in applying the principles in section 8 of the Code (including the principles in sections 8.1 and 8.2), the Commission must apply the principles in a way that recognises the paramount importance of the criteria in section 2.24 of the Code. In relation to Reference Tariffs, the most significant of these criteria that the Commission must take into account:

(a) GasNet's legitimate business interests and investment in the GNS;

(b) the public interest; and

(c) the interests of Users and Prospective Users.

A practical implication of this is that it is in the interests of Users, GasNet and the public for the Commission to take into account the long run benefits of encouraging investment in infrastructure even when this may be perceived to conflict with the short run benefits of, for example, lower tariffs. This "pro-infrastructure" policy is discussed below.

4.3 Benefits of infrastructure

In determining Reference Tariffs, the Commission is required to undertake a delicate balancing exercise between short run and long run goals. This must recognise the benefit that the ongoing development of infrastructure brings and that the long run benefits of investment in infrastructure outweigh the short run benefits of lower tariffs. Ultimately, the debate is not about whether the Commission should "err" on the side of the utility or the consumers, but rather, which course provides the greater long run social welfare. For the reasons discussed below, the preference must be one that promotes investment in infrastructure.

Third party access to infrastructure and, in particular, the pricing of third party access have been the subject of significant public debate since the introduction of Part IIIA of the *Trade Practices Act 1974* (Cth). Recent examples of this have included:

(a) the level and nature of responses to the Productivity Commission Position Paper on the national access regime;

(b) the appeal by Epic Energy against the OffGAR rate determination for the Dampier to Bunbury pipeline; and

(c) the successful application by Duke Energy to ensure the Eastern Gas Pipeline did not become a Covered Pipeline under the Code.

A fundamental issue in this controversy has been the impact of potentially restrictive pricing decisions on infrastructure investment and the broader economic cost of a reduction in infrastructure investment.

The broader social and economic impacts of infrastructure are very substantial. Using the GasNet system as an example:

(a) natural gas is an important input into many industrial processes;

(b) as discussed in section 3.1 of this Submission, the GasNet system serves approximately 1.4 million residential consumers and 43,000 industrial and commercial consumers throughout Victoria; and

(c) as illustrated by the aftermath of the Longford explosion, an interruption to gas supply can have a significant impact on the Victorian economy.

In this context, the pricing of access to infrastructure such as the GasNet system raises a significant social welfare concern. In particular, if investors perceive that the returns from investments such as the GasNet system are inadequate, then this has the potential to deter investment in infrastructure which, in turn, has the potential to cause significant social and economic detriment.

This “disincentive” operates at two levels. It limits the ability of the particular business to raise funds and discourages new investment in upgrades and expansions. On a broader level, it also serves as a disincentive to investors generally investing in new infrastructure. Whatever a regulator may say about its general intentions in relation to greenfields developments or brownfields expansions, the best guide for investors as to the likely future determinations of the Regulator are its past determinations.

This potential disincentive was a significant concern in the seminal Hilmer Committee Report, which expressed the view that:

> *The Committee is conscious of the need to carefully limit the circumstances in which one business is required by law to make its facility available to another. Failure to provide appropriate protection to the owner of such facility has the potential to undermine incentives for investment.*[5]

In its recent review of the national access regime, the Productivity Commission considered the impact of access pricing on investment decisions.

> *The possible disincentives for investment in essential infrastructure services are the main concern. In essence, third party access over the*

[5] Hilmer Committee Report, 1993, page 248.

longer term is only possible if there is investment to make these services available on a continuing basis. Such investment may be threatened if inappropriate provision of access, or regulated terms and conditions of access, lead to insufficient returns for facility owners. While the denial or monopoly pricing of access also impose costs on the community (see above), they do not threaten the continued availability of the essential services concerned. Thus, over the longer term, the costs of inappropriate intervention in this area are likely to be greater than the costs of not intervening when action is warranted. The substantial information and other difficulties that confront regulators in establishing access terms and conditions, make this asymmetry in the benefits and costs of access regulation even more important in a policy context.[6]

Similarly, in its submission to the Productivity Commission, NECG considered the economic impact of access pricing that is too low.

Thus in the long run situation, for a pricing error of a given magnitude, the welfare loss will be significantly greater if the error is in pricing too low rather than too high. This conclusion holds for all average cost curves except those which rise more quickly than demand falls. Such circumstances are unlikely for regulated essential services where supply usually involves large fixed costs and hence declining average costs, and where demand for the essential service is typically inelastic (and hence steep). As has been noted above, the welfare losses associated with low access prices are not immediately apparent, in contrast to the short-term transfers enjoyed by consumers. Nevertheless, economic analysis suggests that these future welfare losses are likely to be extremely high.[7]

In its Position Paper, the Productivity Commission summarised this succinctly when it observed that:

[A]ccess arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions.[8]

The significance of these concerns cannot be underestimated. The determination of Reference Tariffs has ramifications that extend well beyond the corporate, geographic and temporal dimensions of the 2003 Access Arrangements and warrants corresponding treatment.

GasNet submits that these widely-held concerns support GasNet's overall philosophy that in setting terms of access (including pricing) the Commission should adopt a pro-infrastructure approach. In the long run this will lead to benefits to consumers in the form of greater investment and competition in pipelines.

[6] Productivity Commission, *Review of the National Access Regime*, Position Paper, March 2001, p xviii. Note that the Productivity Commission's final report has been signed but not yet released.

[7] NECG, *Submission to the Productivity Commission Inquiry into Part IIIA*, 18 January 2001, p.23.

[8] Productivity Commission, *supra*, p xxi

4.4 Revenue methodology

For the purposes of section 8.4 of the Code, GasNet proposes to retain the Cost of Service Methodology for revenue determination, which is the methodology used in the current PTS and WTS Access Arrangements.

Under a Cost of Service Methodology, the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement Period is, subject to the Code, equal to the cost (or forecast cost) of providing all Services, with this cost to be calculated on the basis of:

(a) a return on the value of the capital assets that form the Covered Pipeline;

(b) depreciation of the Capital Base; and

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

4.5 Form of regulation

For the purposes of section 8.3 of the Code, GasNet proposes to retain the existing “price path” form of regulation.

Under this approach, a set of initial prices and a price control mechanism is determined in advance which will allow the price to follow a path to deliver a forecast revenue stream, but the price control mechanism is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period.

This is discussed further in section 9 of this Submission.

5 Establishing the Capital Base

5.1 Summary of GasNet's proposals

5.1.1 *Code requirements*

Consistent with section 8.9 of the Code, GasNet has calculated the Capital Base for the commencement of the Second Access Arrangement Period by rolling forward the Capital Base from the First Access Arrangement Period and making adjustments for New Facilities Investment, depreciation, inflation and redundant capital. In addition, GasNet proposes to reinstate a number of assets which were included in the original Capital Base valuation but excluded for the purposes of tariff calculation in the First Access Arrangement Period.

5.1.2 *Merging the WTS and PTS*

Currently, GasNet's pipeline assets are split between two Access Arrangements, the PTS Access Arrangement and the WTS Access Arrangement. As a result of the interconnection of the WTS and the PTS, GasNet considers that there are considerable advantages in merging the WTS and PTS Access Arrangements. Therefore, the Capital Base for the new Access Arrangement will include both the WTS and PTS.

5.1.3 *Rolling forward the Capital Base*

In order to establish the Capital Base at the start of the First Access Arrangement Period, GasNet (then TPA) commissioned GHD to provide a valuation of the transmission assets covering both the WTS and PTS. GHD established a value for the regulated assets based on the ODRC methodology, which was accepted by the Commission. However, for the purposes of tariff calculation, certain assets (including easements) were excluded from the Capital Base (this is discussed further in section 5.5 of this Submission). In addition, the Capital Base identified by the Commission in the Final Decision ($363.7 million) was incorrect (the figure used to calculate the Reference Tariffs was $358 million).

For the purposes of calculating the Capital Base for the commencement of the Second Access Arrangement Period, GasNet has rolled forward the rectified Capital Base to reflect all of the assets identified in the GHD valuation.

5.1.4 *New Facilities Investment*

In 1998 the Commission approved various items of forecast capital expenditure for the First Access Arrangement Period totalling $60.7 million. GasNet has completed some of these projects, while it has not completed a number of others, choosing instead to achieve its service obligations under the Service Envelope Agreement by implementing alternative capital projects. In addition, GasNet has completed a number of other projects that were not contained in the forecast capital expenditure. The actual capital expenditure incurred by GasNet in the First Access Arrangement Period was $199.7 million.

A portion of this capital expenditure ($40.4 million) relating to the Interconnect Assets has already been rolled into the Capital Base. As discussed in section 5.8.2 of this Submission, GasNet proposes to include in its Capital Base, approximately $102.1 million (as spent) of the remaining $159.3 million of actual capital expenditure incurred in this period. As a result, GasNet's Capital Base will not include (and Users will not pay Reference Tariffs for) approximately $57.2 million of assets which are in service.

In particular, GasNet proposes to include the value of the SWP in the Capital Base on the basis that it satisfies the economic feasibility test set out in section 8.16 of the Code.

Amounts in respect of the Brooklyn Loop, construction of which has been deferred until 2007, have not been included in the calculation of the Capital Base at the beginning of 2003.

5.1.5 *Depreciation*

GasNet applied the current cost accounting (CCA) framework and a real rate of return for establishing target revenues for the First Access Arrangement Period. Under this framework, the Capital Base was notionally re-valued in line with inflation on an annual basis. A real straight line depreciation profile was adopted to determine the Depreciation Schedule for the First Access Arrangement Period.

As a result of the differences between the forecast and actual capital expenditure, the actual depreciation for the First Access Arrangement Period is different from the forecast depreciation. For the purpose of calculating the Capital Base for the commencement of the Second Access Arrangement Period, GasNet has, used the forecast depreciation adjusted for actual inflation, rather than the actual depreciation.

5.1.6 *Redundant Capital and Disposals*

GasNet has identified one redundant asset, being the North Paaratte Odorant Station, which has been excluded from the Capital Base. In addition, GasNet has disposed of a number of assets including land and vehicles. The Capital Base has been adjusted to reflect these disposals.

5.1.7 *Inflation*

As required by section 8.9 of the Code, GasNet has adjusted the Capital Base for inflation. Consistent with the real rate of return tariff methodology employed by GasNet, the Capital Base has been escalated each year in line with actual inflation. For 2002, GasNet has used a forecast annual inflation rate of 2.5% which is the mid point of the Reserve Bank target range.

5.1.8 *Summary of Capital Base*

A summary of each element of the initial Capital Base is set out in Table 5-1 below.

Table 5-1: Capital Base as at 1 January 1998 ($million)

Elements of Capital Base	Amount ($ million)
Capital Base (as at 1 January 1998) identified by Commission	363.7
Adjustment for excluded assets and incorrect expression	35.8
Rectified Capital Base (1 January 1998)	399.5

Table 5-2 below sets out how the Capital Base was adjusted over the First Access Arrangement period.

Table 5-2: Rolled Forward Capital Base ($ million)

Year ending 31 December	1998	1999	2000	2001	2002
Opening Capital Base	399.5	431.2	518.1	537.7	542.3
Depreciation Allowance	-13.8	-15.2	-17.0	-18.1	-18.3
Capital Expenditure	39.0	93.3	6.2	4.5	0.6
Disposals/Redundancies	-0.2	-0.2	-1.4	-0.1	-0.03
Inflation	6.6	9.0	31.8	18.4	15.2
Closing Capital Base	431.2	518.1	537.7	542.3	539.7

5.2 General

5.2.1 *Regulatory instruments*

The four regulatory instruments relevant to the determination of the Capital Base to be rolled forward from a previous Access Arrangement are:

(a) the Code;

(b) the PTS Access Arrangement;

(c) the WTS Access Arrangement; and

(d) the Fixed Principles under the Tariff Order, to the extent they form part of the Access Arrangements[9].

5.2.2 *Code principles*

The Code sets out a number of general principles in relation to establishing the Capital Base as at 1 January 2003. In addition to the general principles and factors set out in sections 8.1 and 8.2 of the Code, the key provision is section 8.4(a) of the Code, which provides that, under a Cost of Service Methodology, an element of the total revenue includes "a return on the value of the capital assets that form the Covered Pipeline".

[9] See section 2.11 of Schedule 2.

In the context of these general principles, the Code then sets out a number of detailed provisions dealing with a range of specific issues.

(a) Sections 8.10 to 8.14 of the Code set out the principles for establishing the Capital Base for the First Access Arrangement Period. These principles are not relevant to the Capital Base for the Second Access Arrangement Period.

(b) Sections 8.9 and 8.15 to 8.29 of the Code describe principles to be applied in adjusting the value of the Capital Base over time and, in particular, at the commencement of each subsequent Access Arrangement Period after the first.

5.2.3 *Roll-forward to 1 January 2003*

Section 8.9 of the Code outlines the way in which the Capital Base under an Access Arrangement may be rolled forward into the following Access Arrangement Period. It provides that, for the Cost of Service Methodology, the Capital Base at the start of a new Access Arrangement Period is calculated by reference to five components:

(a) the Capital Base at the start of the previous Access Arrangement Period; plus

(b) the New Facilities Investment or Recoverable Portion (whichever is relevant) made during the previous Access Arrangement Period (adjusted to allow for differences between actual and forecast New Facilities Investment); less

(c) depreciation of the Capital Base during the previous Access Arrangement Period; less

(d) any capital which has become redundant during the previous Access Arrangement Period; plus

(e) an adjustment for inflation.

Each of these is discussed in section 5.4 onwards of this Submission.

5.2.4 *Fixed Principles*

The relevant Fixed Principles are set out in clause 9.2(a)(3) of the Tariff Order, which provides that in making the price determination, the Commission should:

> *Use the Capital Base for [GasNet] at the start of the initial regulatory period, adjusted to take account of inflation since 1 January 1998, depreciation, wholly or partially redundant assets and additions and disposals in the ordinary course of business since 1 January 1998, other than a disposal of:*
>
> *(A) all of the assets and liabilities of [GasNet];*
>
> *(B) assets interdependent with the transaction pursuant to which all of the issued shares in or the assets and business of*

[GasNet] ceased to be held by or on behalf of the State of Victoria or a statutory authority; or

(C) assets pursuant to which the assets of [GasNet] are sold and leased back to [GasNet].

As discussed below, these Fixed Principles essentially restate the requirements of the Code.

(a) The requirement to use the Capital Base at the start of the initial regulatory period goes no further than the requirement in section 8.9 of the Code to use the Capital Base at the start of the immediately preceding Access Arrangement Period. As discussed in sections 5.4 and 5.5 of this Submission, GasNet's approach to the Capital Base roll-forward is consistent with this requirement.

(b) The requirement to adjust the Capital Base to take into account inflation goes no further than the requirement of section 8.5A of the Code that the revenue methodology deal with the effects of inflation and the requirement in section 5.10 of the Code that the Capital Base roll-forward be subject to adjustment for inflation. As discussed in section 5.10 of this Submission, GasNet's proposed Access Arrangement revisions are consistent with this requirement.

(c) The requirement to take into account depreciation goes no further than the requirement in section 8.9(c) that the roll-forward of the Capital Base take into account depreciation for the immediately preceding Access Arrangement Period. As discussed in section 5.9 of this Submission, GasNet's proposed Access Arrangement revisions are consistent with this requirement.

(d) The requirement to take into account wholly or partially redundant assets constitutes the redundancy policy contemplated by section 8.27 of the Code. As discussed in section 5.7 of this Submission, GasNet's proposed Access Arrangement revisions are consistent with this policy.

(e) The requirement to take into account additions and disposals of assets in the ordinary course of business (and the related carve-out provisions) do not expressly mirror the provisions of the Code. However, GasNet submits that nothing in its proposed revisions is inconsistent with this requirement.

(i) The reference to "additions" in the ordinary course of business appears to overlap substantially with the concept of New Facilities Investment under the Code. However, the reference to the "ordinary course of business" is potentially confusing. GasNet submits that a broad interpretation should be applied, consistent with the requirements of the Code, and that, in the context of a pipeline business that requires continuous upgrades and expansions, most New Facilities Investment are likely to be "in the ordinary course of business". In particular, GasNet submits that its New Facilities Investment (discussed in sections 5.6 and 5.8 of this

Submission) occurred in the ordinary course of business. If the Commission concludes that any of GasNet's New Facilities Investment do not constitute an addition "in the ordinary course of business", GasNet submits that, consistent with section 8.47 of the Code, the Tariff Order requirement does not apply to the extent of the inconsistency.

(ii) Similarly, the reference to "disposals" in the ordinary course of business is potentially confusing. However, GasNet submits that, on any view, it has not undertaken any material disposal of assets since the commencement of the First Access Arrangement Period.

(iii) The "carve out" provisions are designed to exclude certain corporate restructurings from having an impact on the determination of the Capital Base. The only relevant carve out is in paragraph (B) in relation to the privatisation of TPA. This is consistent with GasNet's overall philosophy that the privatisation and subsequent float of GasNet have no direct bearing on the appropriate asset value to be ascribed to the regulated Capital Base.

(iv) If the Commission concludes that the proposed GasNet Access Arrangement Revisions are inconsistent with any of these requirements (and GasNet maintains that they are consistent), then GasNet agrees under section 8.47 of the Code that the requirement does not apply to the extent of that inconsistency.

5.3 Merging the PTS and WTS into one Capital Base

5.3.1 *Background*

For historic reasons, at the time the PTS and WTS Access Arrangements were approved, the GasNet pipeline assets were split between two Access Arrangements.

(a) The PTS Access Arrangement governed the main transmission system, including the pipelines from Longford to Melbourne. As a result of subsequent extensions, the PTS Access Arrangement now governs the Interconnect Assets and the SWP.

(b) The WTS Access Arrangement governed the transmission system in Western Victoria which linked the Otway Basin with five Western towns, including Portland and Hamilton. In 1998, the WTS was a stand-alone system. However, as a result of the completion of the SWP in 1999, the WTS is now physically interconnected with the PTS. The WTS was, and remains (at the time of this Submission), a "contract carriage" system rather than a "market carriage" system.

5.3.2 *GasNet proposes to merge PTS and WTS Access Arrangements*

As a result of the interconnection between the WTS and the PTS and the continuing maturing of the Victorian gas market, GasNet believes there are considerable advantages in merging the WTS Access Arrangement and the PTS Access Arrangement. In particular, a merger would:

(a) simplify access regulation for all parties;

(b) consolidate access to the Victorian transmission system into a single streamlined process, which would lower the barriers to entry for gas retailers;

(c) ensure an even playing field by applying the market carriage system under the MSO rules to the whole of the GasNet system; and

(d) consistent with interstate practice, ensure there is one transmission access arrangement for each major pipeline system.

5.3.3 *Creating a single system*

GasNet considers that these Access Arrangements can be merged with effect from 1 January 2003 by the following steps.

(a) Terminate the WTS Agreement between GasNet and TXU, which is the only relevant access contract for the WTS under the WTS Access Arrangement. TXU has indicated that it is prepared to consider terminating this agreement, provided it can reach satisfactory agreement with VENCorp in relation to obtaining equivalent capacity rights under an AMDQ credit certificate allocation for the WTS under the MSO Rules. This is discussed in greater detail in clause 5.3.4.

(b) Revise the WTS Access Arrangement and the PTS Access Arrangement to merge the two Access Arrangements.

(c) VENCorp exercises its right under the WTS Approved Connection Deed to declare the WTS to be part of the "gas transmission system", with effect from 1 January 2003.

(d) Once the WTS has been declared to be part of the "gas transmission system" then, under the terms of the PTS Access Arrangement, the WTS is automatically covered by the PTS Access Arrangement.

(e) Apply the principles contained in section 8.9 of the Code to determine the Capital Base of that part of the enlarged PTS constituted by the current WTS.

Each of these steps raises a number of issues, which are discussed below.

5.3.4 *WTS Agreement*

Currently, there is only one User of a Reference Service on the WTS[10]. Its gas is shipped under the WTS Agreement. Under the WTS Agreement, the parties agree to terminate the WTS Agreement upon connection of the WTS to the PTS, subject to a number of conditions precedent.

[10] Another User has a contract for transportation on an "interruptible" basis.

The relevant parties have reached an in principle agreement as to the satisfaction of these conditions. Details of this are being provided to the Commission separately on a confidential basis. GasNet is working actively to resolve these issues and is confident that the conditions can be satisfied prior to 31 December 2002.

5.3.5 *Merging the Access Arrangements*

If the WTS Access Arrangement is merged with the PTS Access Arrangement, a question arises as to whether the WTS Access Arrangement would continue to exist or whether it would simply fall away.

The Code does not contain an explicit statement that an Access Arrangement can "expire" if no revisions are approved by the Regulator. The Code does not provide for the revocation of an Access Arrangement, nor does it specifically provide that an Access Arrangement will expire if no revisions are made to it.

Ordinarily, the failure to submit revisions would lead to the Commission imposing its own revisions pursuant to section 2.45 of the Code.

However, GasNet submits that an Access Arrangement can expire.

(a) Some sections of the Code contemplate the expiry of an Access Arrangement (refer to section 8.14 and to the section 3.17 heading). On this basis, there is a good argument that the WTS Access Arrangement will expire if no revisions have been approved by the Commission, particularly in circumstances where the Commission has approved the incorporation of the WTS into the PTS Access Arrangement.

(b) For greater certainty, the Commission could, utilising its general powers to review an Access Arrangement, approve a revision to the WTS Access Arrangement which fixed a termination date. In this case, the WTS access arrangement could be amended to provide for a termination date of 31 December 2002.

Alternatively, if the Commission does not consider that an Access Arrangement can be made or allowed to expire, GasNet submits that it is open to the Commission to approve amendments to the PTS and WTS Access Arrangement to allow them to merge. GasNet is required under the Code to submit revisions for both the PTS Access Arrangement and the WTS Access Arrangement. GasNet submits that, in complying with this obligation, it can revise both instruments by submitting a single document that will constitute the Access Arrangement for each of the WTS and PTS.

While the Code does not expressly make provision for two Access Arrangements to be merged, GasNet submits that this approach is consistent with other provisions in the Code. For example, the Code allows a Service Provider to have one Access Arrangement governing different parts of the Covered Pipeline. The merging of two separate Access Arrangements for two Covered Pipelines is consistent with this principle.

5.3.6 *Approved Connection Deed*

GasNet and VENCorp are parties to an Approved Connection Deed dated 20 May 1999, which was made under section 5(3) of the *Gas Industry Act 1994* and governs the WTS. Under this Approved Connection Deed, VENCorp may declare the WTS to be part of the "gas transmission system" (as defined under the *Gas Industry Act 1994*) once the WTS is physically connected to the "gas transmission system" and certain facilities are installed. Upon declaration by VENCorp, the WTS will become part of the "gas transmission system" and thus be subject to operation by VENCorp and the MSO Rules.

VENCorp has indicated that it does not intend to make this declaration until TXU, GasNet and VENCorp are satisfied that the conditions precedent for the termination of the WTS agreement have been satisfied.

5.3.7 *Inclusion in PTS Access Arrangement*

The PTS Access Arrangement applies to the "Principal Transmission System" which is defined as follows:

> *"Principal Transmission System" means the Gas Transmission System as defined in the* Gas Industry Act 1994 *excluding any significant extensions in respect of which a notice under clause 5.7.1(c) of this Access Arrangement has been given even if an agreement under section 5(3) of the* Gas Industry Act 1994 *has been entered into in respect of that extension.*

It is unclear whether clause 5.7.1(c) of the PTS Access Arrangement would apply. In any event, GasNet has not given and, assuming satisfactory resolution of these issues, does not intend to give a notice under clause 5.7.1(c) in relation to the WTS.

Therefore, once VENCorp makes the declaration under the Approved Connection Deed discussed in section 5.3.6 above, the WTS will become part of the "gas transmission system" and part of the PTS within the meaning of the PTS Access Arrangement. That is, once VENCorp makes the declaration under the Approved Connection Deed, the PTS Access Arrangements will automatically apply to both PTS and the WTS.

To avoid the potential ambiguities associated with having two access arrangements applying to a single pipeline, GasNet proposes that the VENCorp declaration take effect on the same day as the WTS Access Arrangement and PTS Access Arrangement merge.

5.3.8 *WTS capital base*

If the WTS becomes covered by the PTS Access Arrangement, the question arises as to how the Capital Base previously included in the WTS Access Arrangement is treated under the PTS Access Arrangement.

GasNet submits that the treatment of the WTS Capital Base is adequately addressed by section 8.9 of the Code, which provides that:

The Capital Base at the commencement of each Access Arrangement Period after the first, for the Cost of Service Methodology, is determined as:

(a) the Capital Base at the start of the immediately preceding Access Arrangement Period; plus

(b) the New Facilities Investment or Recoverable Portion (whichever is relevant) in the immediately preceding Access Arrangement Period (adjusted as relevant as a consequence of section 2.22 to allow for the differences between actual and forecast New Facilities Investment); less

(c) depreciation for the immediately preceding Access Arrangement Period; less

(d) Redundant Capital identified prior to the commencement of that Access Arrangement Period.

GasNet considers that these are the principles that should be applied to determine the Capital Base for the part of the GNS constituted by the current WTS.

This approach is also consistent with the Commission's Final Decision in relation to the PTS and WTS Access Arrangement. In that decision, the Commission approved a consolidated capital base value incorporating both the PTS and the WTS. Therefore, the merger of the PTS and WTS into a single Access Arrangement does not present any practical difficulties in relation to the determination of an aggregate Capital Base.

5.4 Initial Capital Base roll-forward to 1 January 2003

This section and section 5.5 identify the Capital Base to be rolled forward from the current Access Arrangement Period to 1 January 2003 and, in accordance with section 8.9 of the Code, the Capital Base of the current WTS Access Arrangement.

5.4.1 *Initial Capital Base*

Section 8.9(a) of the Code requires the Commission to identify the Capital Base at the start of the immediately preceding Access Arrangement Period. This raises three issues.

(a) The start date of the First Access Arrangement Period.

(b) The Capital Base of the PTS and WTS at the start of the First Access Arrangement Period.

(c) The additional amount added to that Capital Base as a result of the inclusion of the Interconnect Assets, which were rolled in to the Capital Base during the First Access Arrangement Period.

5.4.2 *Start Date*

Under the Code, an Access Arrangement Period is defined as the period from when an Access Arrangement takes effect until the next Revisions Commencement Date.

Although the WTS and PTS Access Arrangements came into effect on 1 January 1999 and 15 March 1999 (respectively), for tariff calculation purposes, both Access Arrangements utilise an asset base valued as at 1 January 1998.[11]

In its approval of the PTS and WTS Access Arrangements, the Commission accepted a flexible start date (ie other than 1 January 1998) in circumstances where the tariffs had been calculated as if the Cost of Service Methodology (including inflation and depreciation of the Capital Base) had been applied from 1 January 1998. As a result, it was not necessary for the Commission to calculate the specific Capital Base as at the date the Access Arrangements took effect.

This rationale is equally applicable for the purposes of calculating the Capital Base for the Second Access Arrangement Period. In particular, GasNet submits that, consistent with its 1998 decisions, the Commission can simply start with the Capital Base as at 1 January 1998. By applying the Cost of Service Methodology, the Commission will obtain the same result as it would if it were to calculate the value of the Capital Bases as at 1 January 1999 and 15 March 1999. However, utilising the 1 January 1998 Capital Base is much simpler, as it avoids the need for an artificial intra-period "snapshot" valuation.

5.4.3 *PTS and WTS Capital Base*

In its 1998 Determination, the Commission concluded, based on a valuation prepared by GHD for EPD, that a fair value for the initial asset base of the PTS and WTS was $363.7 million (as at 1 January 1998).

As discussed in section 5.5, there were a number of omissions from the final valuation which EPD provided to the Commission, which GasNet seeks to have rectified.

5.4.4 *Interconnect Assets*

In 1999, GasNet applied to increase the Capital Base of the PTS to account for the Interconnect Assets as New Facilities Investments.

Subsequently, in its Final Decision of 28 April 2000, the Commission approved the roll-in of the Interconnect Assets.

The Commission approved an amendment to the reference tariffs which reflected the following additions to the PTS Capital Base:

(a) Interconnect Pipeline: $19.5 million capital cost included as at 15 July 1998; and

[11] See section 2.2.1 of Schedule 2.

(b) Springhurst Compressor and Interconnect Valves: $20.9 million as at 31 May 1999.

5.5 Assets excluded from initial Reference Tariffs

5.5.1 *GasNet Proposal*

The Code does not permit the Commission to undertake a revaluation of the initial GasNet Capital Base.

However, the Code does require the Commission to verify that the Capital Base expressed in the text of the Commission's Final Decision accurately reflects GasNet's Capital Base (in this case, as expressed in the 1998 GHD valuation). GasNet submits that there were a number of errors and omissions in the expression of the Capital Base in 1998 that require verification.

In order to establish the Capital Base at the start of the First Access Arrangement Period, GasNet (then TPA) commissioned GHD to provide a valuation of the transmission assets. GHD established a value for the assets based on the ODRC methodology for the period ending 30 June 1997 which was subsequently rolled forward to 1 January 1998.

However, the initial asset base identified by the Commission ($363.7 million) contained a number of errors and omissions which should now be rectified. In particular, the initial asset base identified by the Commission:

(a) omitted an allowance for the value of easements which were valued by GHD at $40.2 million (GasNet understands that a policy decision was taken by EPD to exclude this amount from the initial tariff calculation in order to meet the State Government's objectives of imposing maximum uniform tariffs);

(b) omitted an allowance for a number of pipeline regulators and associated remote terminal units, which amounted to $1.9 million (GasNet understands that, on the basis of information provided in the GHD valuation, EPD assumed that the assets were connection assets (ie non-regulated assets) and therefore excluded them from the calculation of the Capital Base. The error was identified by TPA in the period between the date the Draft Decision was handed down and the date the Final Decision was handed down. However, EPD did not seek to revise the Capital Base to include the regulators.);

(c) omitted amounts in relation to the reduction in value of the WTS and the Lurgi pipeline which amounted to $9 million and $1.2 million respectively (GasNet understands that a policy decision was taken by EPD to exclude this amount from the initial tariffs in order to meet the State Government's objectives of imposing maximum uniform tariffs. GasNet believes these reasons continue and therefore proposes to maintain these exclusions.);

(d) omitted the value of the Murray Valley pipeline, which was completed in 1998 prior to the Final Decision (the capital cost of $15.7 million was incorrectly classified as forecast capital expenditure); and

(e) incorrectly expressed the balance of the assets as $363.7 million[12], when the actual balance (and the amount used to calculate the Reference Tariffs) was $358.0 million (it appears the Commission used the June 1997 figures instead of the January 1998 figures).

GasNet considers that the Code requires the Commission to identify, as an independent step, the Capital Base at the start of the First Access Arrangement Period. For the reasons discussed above, GasNet considers that the correct Capital Base at 1 January 1998 is $399.5 million.

5.5.2 *Code requirements*

The principles for establishing the Capital Base for each Access Arrangement Period after the first are set out in section 8.9 of the Code. It provides that, for the Cost of Service Methodology, the Capital Base at the start of a new Access Arrangement Period is determined as "*the Capital Base at the start of the immediately preceding Access Arrangement Period*" (with adjustments for New Facilities Investment, depreciation and Redundant Capital).

5.5.3 *GasNet's submission*

GasNet submits that the better approach to rolling forward the Capital Base for the commencement of the Second Access Arrangement Period is to reflect the actual assets identified in the GHD valuation of the Capital Base, which rectifies the errors identified in section 5.5.1 of this Submission (the "**Actual Capital Base**").

This approach is to be preferred over the application of the (lower) valuation determined by EPD for tariff purposes and approved by the Commission in its Final Decision on the initial Access Arrangements (the "**Tariff Capital Base**").

On one interpretation of section 8.9 of the Code, it might be argued (GasNet submits incorrectly) that the provision allows only a mechanical roll forward of the Capital Base from the start of the immediately preceding Access Arrangement Period, without any adjustments to take account of any errors or omissions from the original valuation. For example, in section 3.1.2 of the Final Decision, the Commission suggested that:

> *The appropriate formula for determining the capital base at the commencement of the next access arrangement period is:*
>
> *Capital base = initial capital base (indexed) - depreciation (indexed) + new facilities investment (indexed) - redundant capital*
>
> *The Commission notes that the Victorian Access Code does not provide scope to revalue the existing assets outside of what is permitted by this formula.*

On this basis, the value of the Capital Base to be rolled forward would be the one previously used by the Commission (ie the Tariff Capital Base). Applying this approach, the Capital Base would be set in stone at the

[12] ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998), section 3.2.2

commencement of the First Access Arrangement Period and could not be revisited in any circumstances.

However, GasNet submits that this interpretation is incorrect. This interpretation amounts to an assertion that the Capital Base constitutes whatever was identified by the Commission as the Capital Base, without any regard for any defects (including manifest errors). This cannot have been the intention of the Code.

GasNet submits that the better view is that, while the Code gives participants a level of certainty by placing some constraints on the valuation of the Capital Base (for example, a total revaluation is not permitted), section 8.9 of the Code requires the Commission to identify, as an independent exercise, the Capital Base at the start of the First Access Arrangement Period and, in the course of that identification, it enables the Commission to verify whether the Capital Base was correctly expressed in the previous Access Arrangement Period.

The main constraint on this identification process appears to arise from the words in sections 8.8 and 8.9 of the Code, which provide that:

> *Principles for establishing the Capital Base for the Covered Pipeline when a Reference Tariff is first proposed for a Reference Service (ie for the First Access Arrangement Period) are set out in sections 8.10 to 8.14.*
>
> *Sections 8.15 to 8.29 then described the principles to be applied in adjusting the value of the Capital Base over time ...*

It might be argued that these sections imply that the Capital Base identified by the Commission in the final decision is "locked in" and not subject to change for any reason. However, GasNet's submits that the better view is that, while these provisions prevent the Commission from revaluing the Capital Base, there are circumstances in which the Commission may, in the process of determining tariffs for a subsequent access arrangement period depart from the Capital Base expressed in the Final Decision.

(a) Section 8.9(a) of the Code provides that the Capital Base at the commencement of each Access Arrangement Period after the first is to be determined by applying the Capital Base at the start of the immediately preceding Access Arrangement Period. It does not expressly provide that the Capital Base to be rolled forward is the Capital Base approved (or used) by the Relevant Regulator at the start of the immediately preceding Access Arrangement.

(b) "Capital Base" is defined in the Code as the value of the capital assets that form part of the Covered Pipeline. The value of the capital assets that formed the Covered Pipeline at the start of initial Access Arrangement included all of the assets employed in delivering the Service including the easements and other assets referred to in clause 5.5.1 and identified in GHD's valuation.

(c) A strict interpretation of the Code would mean that the Commission is precluded from revisiting any aspect of the Capital Base, even manifest errors. The absurdity of this interpretation is illustrated by the fact that the Commission incorrectly stated a higher capital base in its Final Decision than the Capital Base used to calculate the tariffs. GasNet submits that the provisions of the Code are sufficiently broad to enable the Commission to rectify manifest errors of this kind.

(d) GasNet accepts that the Code does place constraints on the ability of the Commission to revisit the Capital Base. In particular, the Code does not permit the Commission to undertake a revaluation of the Capital Base. However, the items which GasNet is seeking to rectify do not constitute a revaluation. Rather, they seek to reconcile the Capital Base back to the original GHD valuation, which was accepted by the Commission.

(e) This approach is consistent with the requirement in section 2.24 of the Code that the Commission must take into account GasNet's legitimate business interests and investment in the GasNet system and with the underlying principle in section 8.1(a) of the Code of providing a Service Provider with the opportunity to earn a stream of revenue that recovers the costs of delivering a Service over the expected life of the assets used in delivering that Service.

Alternatively, GasNet submits that the exercise of that discretion to approve the Capital Base in 1998 should be properly construed as applying only to the particular regulatory period to which it relates.

Therefore, GasNet submits that the exercise of that discretion applied only to the First Access Arrangement Period and that the Capital Base at the start of Second Access Arrangement Period should be identified as an independent exercise to reflect the requirements of section 8.10 of the Code.

On this basis GasNet submits that, for the purpose of determining the Capital Base at the commencement of the Second Access Arrangement Period, the Capital Base at the start of the First Access Arrangement Period should include the value of the easements and the pipeline regulators.

GasNet does not propose to adjust the Capital Base to reverse the write down of the WTS and Lurgi pipeline as the factors which lead to the write down continue to operate.[13]

5.5.4 *Establishing value of easements*

The appropriate method of evaluating easements is an issue of some controversy and has been considered in a number of regulatory decisions, particularly in the context of electricity transmission networks.[14]

[13] See section 5.5.1(c) of this Submission.

[14] See for example, ACCC, *NSW and ACT Transmission Network Revenue Caps Decision 1999/2000-2003/04*, (Final, 2000), p 49; and ACCC, *Queensland Transmission Network Revenue Cap Decision 2002-2006/7* (Final, 2001), p 42.

The Commission considered the manner in which easements should be treated in its draft Statement of Principles for the Regulation of Transmission Revenues ("**Draft Regulatory Principles**") which it released in May 1999.

In its Draft Regulatory Principles the Commission stated that:

> *"The normal DORC methodology would assign values to such assets [easements] reflective of their market value. Given the strong link with real estate there is a likelihood that the value of easements will escalate continuously over time, at times in excess of the rate of increase in the CPI. The question is how to introduce such assets into the regulatory framework in a consistent way. One consistent approach would require:*
>
> - *The contribution to the regulatory asset base be based on the actual cost to the Transmission Network Service Provider of obtaining the easement rights updated periodically in line with what would be the DORC based valuation of easements. On the basis of legislated mechanisms for purchase of easements both of these valuations would normally be in line with what was considered the loss of amenity to the previous owner of conceding the easement right (that is its social cost).*
>
> - *To the extent that easement valuations are judged to vary over time, the variations in value should be reflected in depreciation allowances linked with the asset in precisely the same way as other assets. If the easement appreciates in value over time then the allocated depreciation would be negative in nominal terms and serve to offset the higher capital returns associated with an appreciating asset value…."*[15]

Although the Draft Regulatory Principles apply to the valuation of easements in the context of the electricity transmission network, GasNet submits that there is no reason in principle why the same valuation methodology should not be applied to valuation of easements in the context of gas transmission networks. Despite the fact that the level of maintenance required on gas transmission easements is generally less than is required on electricity transmission easements, GasNet's easements are just as essential to the operation of the pipeline as electricity easements are to the operation of the electricity transmission system. In particular, the easements are essential to ensure the safe operation of the pipeline and to protect the pipeline from accidental damage by third parties.

For example, as part of the process for obtaining a pipeline permit and licence, GasNet is required to obtain easements for the protection of the pipeline. Section 12AB(1) of the *Pipelines Act 1967* (Vic) requires that, if the pipeline route affects private land or native title, then the Minister is not to grant the permit unless satisfied that any necessary interests have been acquired by agreement or are to be acquired compulsorily, in accordance with Section 22. Section 12AB(2) provides that compensation and other expenses

[15] ACCC, *Draft Statement of Principles for Regulation of Transmission Revenues*, 27 May 1999 p 45.

for these interests are payable by the applicant. Departmental practice is to require evidence that GasNet has acquired easements and negotiated native title before it will grant a permit. The costs of easements is an integral part of pipeline construction costs.

Similarly, as part of GasNet's safety case, easements provide a significant contribution to the pipeline's protection from third parties. The easements are registered on title and provide an awareness of the existence of the pipeline. The restrictive covenants attached to the easement prohibit certain actions and activities on the easement that may place the integrity of the pipelines at risk.

The alternative of avoiding easements by having the transmission pipelines in road reserves is not practical and the cost of construction would be prohibitive.

GasNet submits that the GHD valuation of the easements is consistent with the Commission's preferred approach. The GHD valuation of easements involved estimating the land area covered by the easements and then estimating the average land values which the easements covered. The final figure of $40.15 million was arrived at by adopting average compensation rates, including injurious affection of 35% for "rural land" and 40% for "residential and industrial land".[16]

GasNet submits that the GHD valuation of GasNet's easements is consistent with the ACCC's Draft Regulatory Principles and should be adopted as the appropriate valuation of GasNet's easements.

The validity of this valuation is supported by a subsequent valuation commissioned by GasNet. In 1999, A.T. Cocks Consulting valued the replacement cost of GasNet's easements at $108 million. This figure included fixed costs such as valuations, cost of negotiations, as well as injurious affection, solatium and damages compensation from construction. The actual cost of the purchase of the "interest" in the land (based on a percentage of freehold value) was determined as being approximately $43 million. Costs of negotiating Native Title are not included in these figures.

Therefore, GasNet proposes to include easements in its Capital Base utilising the 1998 value determined by GHD and escalated to take into account inflation.

As this is the first time easements will be included in the determination of Reference Tariffs the issue of updating the valuation for the period up to 1 January 2003 (and the associated "negative depreciation") does not arise. Going forward, easements will be depreciated at the same rate as the associated pipelines (on the basis that once the pipeline's life has ended, the life of the easement has also ended. This is discussed further in section 7.4 of this Submission).

[16] Gutteridge Haskins & Davey Pty Ltd, *Gas Transmission Corporation - Report on Valuation of Victorian Gas Transmission Network*, July 1997, pp 14-15.

5.6 New Facilities Investment - SWP

5.6.1 *GasNet's Proposal*

GasNet proposes to increase the Capital Base from 1 January 2003 to include in its Capital Base, capital costs associated with the SWP under the economic feasibility test in the Code. GasNet has proposed a stand alone tariff that recovers only a portion of the actual capital costs over the life of the SWP (GasNet is not seeking to recover the balance of the actual capital cost). As a stand alone tariff, the new tariff will not impose burdens on Users who do not utilise the SWP.

The key features of GasNet's proposal are that:

(a) GasNet proposes to include only $75.5 million[17] of the actual capital cost of the SWP in the Capital Base, as the $7.3 million balance between this and the actual cost represents the costs of an accelerated construction program;

(b) the costs of the SWP will be reflected in a new stand-alone injection tariff ($4.0860/GJ, based on 10 day peak injections, which is comparatively higher than the proposed Longford injection tariff) to be paid only by Users of the SWP; and

(c) GasNet is confident that, even with the stand-alone tariff, sufficient volumes are likely to flow on the SWP (particularly from the new discoveries in the Otway basin such as Thylacine and Geographe) to recover the cost of the SWP and therefore the SWP can be included in the Capital Base on the basis that it passes the economic feasibility test set out in section 8.16(b)(i) of the Code.

5.6.2 *Detailed analysis*

For a range of largely historical reasons, the inclusion of the SWP in the Capital Base, involves an analysis of a number of complex legal and economic issues. These are discussed in detail in Schedule 3.

5.7 Redundant capital

5.7.1 *Redundant capital policy*

As contemplated by section 8.27 of the Code, the PTS Access Arrangement includes a mechanism dealing with the removal of redundant capital[18]. In particular:

(a) clause 9.2(a)(3) of the Tariff Order provides that, for the Second Access Arrangement Period, the Commission is to adjust the Capital Base to take account of "wholly or partially redundant assets"; and

(b) clause 5.3.5 of the PTS Access Arrangement states that, as set out in clause 9.2(a)(3) of the Tariff Order, the Commission may review, and

[17] Although the actual amount to be rolled-in has been escalated.

[18] GasNet proposes to revise this mechanism - see section xx of this Submission.

if necessary, adjust the Capital Base (at the start of the subsequent Access Arrangement Period) to take account of "wholly or partially redundant assets".

These provisions were included in the Tariff Order and the Access Arrangements as the result of an explicit determination of the Commission as part of its Final Decision. In particular, the Commission noted that:

> *Of concern to the Commission is the omission of redundant assets from the formula which calculates the asset base of the start of the subsequent regulatory period and the potential this has for users to pay for assets that have ceased or substantially ceased to contribute to the delivery of services*[19].

For the Second Access Arrangement Period, GasNet proposes to adopt a revised capital redundancy policy (see section 9.7 of this Submission).

5.7.2 *Capital redundancy*

GasNet submits that the only capital redundancy that has occurred or is likely to occur during the First Access Arrangement Period relates to the North Paaratte Odorant Station. This station, which was included in the initial Capital Base, has since ceased operation and no longer contributes to the operation of the GNS. GasNet has excluded this asset (which is valued at $0.1 million) from the Capital Base. Under section 2.28 of the Code, this asset may be reinstated at a later date if it subsequently contributes to the GNS.

5.7.3 *Disposals*

GasNet has disposed of a number of assets during the course of the First Access Arrangement Period including land and vehicles. These assets, which amount to $1.8 million, have been removed from the Capital Base.

5.8 New Facilities Investment - Forecast vs Actual

5.8.1 *Code requirements*

One of the items to be considered in the determination of the Capital Base at the commencement of the Second Access Arrangement Period is the New Facilities Investment or Recoverable Portion (whichever is relevant) in the current Access Arrangement Period (adjusted as relevant as a consequence of section 8.22 of the Code to allow for differences between the actual and forecast New Facilities Investment).

Section 8.22 of the Code provides that either the Reference Tariff Policy should describe or the Regulator shall determine whether (and how) the Capital Base at the commencement of an Access Arrangement Period should be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives in section 8.1 of the Code).

[19]ACCC, *Victorian Gas PTS Access Arrangement* (Final 1998), p 35

Section 8.2.1 sets out a streamlined process for dealing with revisions to the Capital Base where the New Facilities were forecast at the commencement of an Access Arrangement Period and were factored into the Reference Tariffs for that period.

5.8.2 *GasNet's proposals*

Where New Facilities Investment satisfies the requirements of section 8.16 of the Code, it can, in accordance with sections 8.9(b) and 8.22 of the Code, be included in the Capital Base.

Under GasNet's current Access Arrangement, New Facilities Investment which does not pass the economic feasibility test at the time they were constructed may be included in a Speculative Investment Fund. So, for example, as discussed in Schedule 3 to this Submission, the Commission found that the SWP did not pass the economic feasibility at the time the application was made. Therefore, the amount representing the SWP has been included in a Speculative Investment Fund.

Section 8.22 of the Code sets out a procedure for dealing with how New Facilities Investment is to be determined for the purposes of section 8.9 of the Code. GasNet submits that the purpose of this section is to deal with under or overspends on forecast capital expenditure or where capital was expended on a project which is similar, but not identical to, the one forecast.

Section 8.22 does not deal with major items of capital expenditure which were not forecast at the commencement of an Access Arrangement Period. These items are subject to the same test (ie they must pass section 8.16 of the Code in order to be included in the Capital Base) but are considered independently of sections 8.21 and 8.22.

In its Final Decision, the Commission approved Reference Tariffs which incorporated forecast capital expenditure of $60.7 million, which was regarded as being reasonably expected to pass the requirements for New Facilities Investment when the investment was forecast to occur.

GasNet has completed some of these projects, while it has not completed others, choosing instead to achieve its service obligations by implementing alternative capital projects. In addition, GasNet has completed a number of other projects that were not contained in the forecast capital expenditure which were believed to be more optimal capital projects.

Table 5-3 below details the differences between actual capital expenditure incurred and forecast capital expenditure during the First Access Arrangement Period.

Table 5-3: Capital Expenditure Reconciliation Table ($million)*

CAPITAL EXPENDITURE RECONCILIATION										
	1998 ($million)		1999 ($million)		2000 ($million)		2001 ($million)		2002 ($million)	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
Pipelines	34.40	34.37	0.15	65.77	29.89	0.02	1.27	0.00	0.16	0.04
Compressors	0.67	2.74	4.06	66.02	1.93	5.98	0.84	3.96	0.41	0.08

CAPITAL EXPENDITURE RECONCILIATION										
	1998 ($million)		1999 ($million)		2000 ($million)		2001 ($million)		2002 ($million)	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
Odorisation	0.10	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
City Gates & Field Regulators	0.52	0.60	0.00	18.13	0.00	0.04	0.00	0.00	0.00	0.00
Gas Quality Facilities	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Land & Buildings (Transmission Share)	0.01	0.03	0.03	0.15	0.03	0.02	0.03	0.12	0.03	0.12
Other (Transmission Share)	0.10	0.23	0.17	0.66	0.18	0.13	0.14	0.21	0.14	0.21
TOTAL	35.79	38.14	4.41	150.73	32.03	6.19	2.38	4.28	0.74	0.33
VARIANCE	2.35		146.32		-25.84		1.90		-0.41	

* The forecast figures in this table include an amount for the Interconnect.

Variance = Actual - Forecast

Table 5-4 sets out the differences between forecast and actual capital expenditure by project.

Table 5-4: Actual Capital Expenditure 1998-2002 ($ million)

Project Description	Forecast	Actual
Gooding Compressor automation	1.50	2.48
Brooklyn Compressor automation	2.69	4.20
Brooklyn compressor restaging and gas cooler upgrade	1.07	1.80
Brooklyn Loop	27.15	-
SWP	-	82.80
Interconnect Assets	-	42.18
Bulla Park Compressor (a)	-	28.10
Young Compressor (a)	-	19.56
Murray Valley Pipeline (b)	15.63	15.63
General Maintenance Capital Expenditure	7.61	1.10
Non-System Capital Expenditure	1.07	1.82
Total	56.72	199.67

(a) These assets are owned by GasNet and support the GNS. However, as they are situated in NSW, they do not form part of the Capital Base of the GNS.

(b) This amount was incorrectly classified as forecast capital expenditure, even though the Murray Valley pipeline had in fact been completed.

The actual capital expenditure incurred by GasNet in the First Access Arrangement Period was $199.6 million. A portion of this capital expenditure ($40.4 million) relating to the Interconnect Assets, has already been rolled into the Capital Base. GasNet proposes to include in its Capital Base an additional $102.0 (as spent) of the remaining capital expenditure. The justification for these projects to be included in the Capital Base is discussed in section 5.8.4 of this Submission.

5.8.3 *Brooklyn Loop*

In the Final Decision, the Commission expressed concern as to the forecast capital expenditure associated with the Brooklyn Loop, which, as incorporated into the tariff model, generated an additional $4 million revenue for each of the last two years of the First Access Arrangement Period. In particular, the Commission was concerned that, if the Brooklyn Loop did not proceed, then it was possible that GasNet would reap a windfall gain by receiving additional revenue without the requirement to incur capital expenditure.

One of the conditions imposed by the Commission in the Final Decision was that the Service Envelope Agreement include an obligation on GasNet to construct the Brooklyn Loop.[20] As a result, the Service Envelope Agreement was amended to require that capital expenditure attributable to these developments must be removed from the Capital Base if those developments did not become part of the gas transmission system by 31 December 2002. The qualification identified by the Commission that GasNet might provide equivalent capacity, was not included in the Service Envelope Agreement.

In the event, GasNet has deferred the construction of the Brooklyn Loop until 2007 due to a number of significant changes in circumstances.

At the time the PTS Access Arrangement was prepared in 1998, the following assumptions were made.

(a) There would be a shortfall in supply in 2001 due to a contractual step-down at Longford.

(b) It was anticipated that the WUGS facility would supply this shortfall.

(c) A SWP would be required to supply gas from the WUGS facility at Iona into Melbourne (although not necessarily constructed by GasNet).

(d) The Brooklyn Loop was needed in order to allow the supply from the WUGS facility to meet unsupplied peak demand.

Given these assumptions, GasNet's predecessors proposed to construct the Brooklyn Loop in 2001 to enable the WUGS facility to supply Melbourne at its full capacity.

It became apparent by November 1999 that the original forecasts of the peak flows used in the tariff model assumptions were too high. At this time, VENCorp published a significantly lower forecast of peak flows. It became clear to GasNet that the additional capacity to be provided by the Brooklyn Loop would not be required.

In addition, a number of events led to changes in the original forecast assumptions. Most noteworthy was the Longford fire and explosion which lead to the construction of the Moomba to Melbourne augmentation project. This project provided 92 TJ per day of capacity into Victoria by June 1999.

[20] ACCC, *Victorian Gas PTS Access Arrangement* (Final, 2001), p 71.

However, only part of this project, the Interconnect Pipeline and the Springhurst Compressor, was included in GasNet's asset base. These assets provided up to 50 TJ of capacity per day. The remaining 42 TJ of capacity is provided by the two GasNet compressors at Bulla Park and Young on the EAPL system. These assets have not been included in GasNet's regulatory asset base.

Subsequent to the Longford fire and explosion, the WUGS facility and the SWP were completed ahead of schedule in 1999.

As a result of these and other measures taken by GasNet, GasNet was able to deliver its required level of service in the most efficient manner without the need to undertake the construction of the Brooklyn Loop. This is consistent with the Code and the incentive mechanism applying to GasNet in the First Access Arrangement Period.

In the Final Decision, the Commission specifically contemplated that this might occur. For example, in section 3.2 of the Final Decision, the Commission observed that:

> *In the event that the owner can deliver the same level of service at a lower capital cost than forecast - dynamic efficiency in other words - the owner will receive the benefit.*

Similarly, in section 3.8.2 of the Final Decision, the Commission observed that the capital expenditure regime:

> *is meant to provide [GasNet] with an incentive to find the most efficient way to provide the necessary capacity…*

As contemplated by the amendments to the Service Envelope Agreement, GasNet proposes that the capital costs associated with the Brooklyn Loop (and which formed part of the forecast capital expenditure in the PTS Access Arrangement) be excluded from the Capital Base to apply at the commencement of the Second Access Arrangement Period.

5.8.4 *Actual New Facilities Investment*

Section 8.21 of the Code provides that:

> *if the Relevant Regulator agrees to Reference Tariffs being determined on the basis of forecast New Facilities Investment, this need not (at the discretion of the Relevant Regulator) imply that such New Facilities will meet the requirements of section 8.16 when the Relevant Regulator considers revisions to an Access Arrangement submitted by a Service Provider.*

Section 8.16 of the Code provides that Capital Base may be increased by the actual capital costs incurred provided that:

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

(b) one of the following conditions is satisfied:

   (i) the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment ("**Economic Feasibility Test**"); or

   (ii) the New Facility has system-wide benefits that justify the approval of higher Reference Tariffs for all Users ("**System-wide Benefits Test**"); or

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

The major items of capital expenditure incurred by GasNet for the PTS for the period up to 31 December 2001 were:

(a) Interconnect Assets;

(b) SWP;

(c) two compressor station automations;

(d) Brooklyn compressor restaging and gas cooler upgrade; and

(e) The assets of Melbourne-Moomba Augmentation project installed on the EAPL pipeline (although GasNet does not seek to include these assets to its Capital Base).

Neither the Interconnect Assets nor the SWP were included in GasNet's original forecast capital expenditure. In relation to the Interconnect Assets, the Commission has already approved revisions to GasNet's tariffs to account for the costs associated with those assets. GasNet's submission in relation to the SWP is set out in section 5.6 of this Submission and Schedule 3.

The justification for the other items of capital expenditure incurred is discussed below.

Compressor station automation

The Brooklyn and Gooding compressor stations required upgrading to their control systems to allow reliable remote operation of the system by VENCorp. The Gooding compressor station automation was commissioned in 1999 at a cost of $2.5 million and the Brooklyn automation was commissioned in 2000 at a cost of $4.2 million.

Automation of the Brooklyn compressor was completed at a station level but at a unit level was restricted to the two Centaur units which are the dominant operational units. Automation of the four Saturn units within the station was not considered prudent on the basis that the benefits could not justify the costs.

In addition to allowing the remote operation of the system by VENCorp, the automation of the compressor stations was required for a number of reasons.

(a) The existing control technology was dated, with poor reliability and poor functionality.

(b) It was becoming increasingly difficult to source spare parts from the original equipment manufacturers.

(c) The introduction of the gas market demanded higher levels of operational reliability. For example, as market dynamics drive the compressor scheduling, prompt and reliable unit starting, stopping and variable speed control was required.

(d) The large uplift penalties associated with system constraint caused by equipment failure meant that a greater level of equipment reliability was required.

(e) In relation to the Brooklyn compressor station, the existing technology could not ensure optimal unit, valving or running configuration, particularly in the light of the various new station duty cycles required for the operating system. The new station duties include winter pressure boosting to supply the Ballarat system, injection of gas into the metropolitan system at Brooklyn and summer pressure boosting to supply withdrawals from the system for injection into WUGS.

GasNet submits that, for the reasons identified above, the capital expenditure was justified on the basis that it was necessary to maintain the safety and integrity of the system (ie section 8.16(b)(iii) of the Code).

Tenders were sought for both the design and implementation of the station control technology and the lowest final cost solution was adopted. On this basis GasNet submits that both the Gooding and Brooklyn compressor station automations satisfy the prudency test set out in section 8.16(a) of the Code.

Brooklyn compressor station restaging and gas cooler upgrade

Under the Service Envelope Agreement approved by the Commission, GasNet was required to complete the restaging of the Brooklyn compressor. The Brooklyn compressor restaging was commissioned in the summer of 1999/2000 at a cost of $1.8 million.

GasNet submits that the restaging of the compressors and gas cooler upgrade were justified on the basis that it was essential to meet the new station duty requirements. The restaging was part of the overall system upgrade which was required to maintain system deliverability beyond 2000. In particular, the restaging was essential to provide the higher flows and pressures for summer injections of gas into WUGS. The compressor had previously been staged for much lower delivery pressures to supply the Geelong and Ballarat systems and the existing coolers had insufficient cooling capacity to meet the new station needs.

The compressor restaging was carried out by the original equipment manufacturer. In relation to the upgrading of the coolers, tenders were sought and the lowest final cost option was adopted. On this basis, GasNet submits that capital expenditure satisfies the prudency test set out in section 8.16(a) of the Code.

5.9 Depreciation 1998-2002

5.9.1 *Code requirements*

Section 8.9 of the Code provides that, in determining the Capital Base at the commencement of each Access Arrangement Period, *Depreciation for the immediately preceding Access Arrangement Period* must be taken into account.

5.9.2 *Depreciation Methodology*

GasNet applied the current cost accounting (CCA) framework and a real rate of return for establishing target revenues for the First Access Arrangement Period. Under this framework, the Capital Base was notionally re-valued in line with inflation on an annual basis. A real straight line depreciation profile was adopted to determine the Depreciation Schedule for the First Access Arrangement Period.

5.9.3 *GasNet's proposal*

As a result of the difference between forecast and actual New Facilities Expenditure, an issue arises as to whether, for the period prior to 1 January 2003, the Capital Base should be depreciated on the basis of the forecast capital expenditure or whether it should be depreciated on the actual capital expenditure incurred in the First Access Arrangement Period.

In establishing the Capital Base for the commencement of an Access Arrangement Period, section 8.9 of the Code requires the Capital Base at the commencement of the immediately preceding Access Arrangement Period be written down by the Depreciation for the immediately preceding Access Arrangement Period.

The term *Depreciation* is defined as:

> *in any year and on any asset or group of assets, the amount calculated according to the Depreciation Schedule for that year and for that asset or group of assets.*

The term *Depreciation Schedule* is defined as:

> *the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the Covered Pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of determining a Reference Tariff.*

These provisions of the Code appear to contemplate a mechanical application of the Depreciation Schedule. On this basis, the Depreciation Schedule would be applied without any adjustment to reflect the expenditure on actual assets. That is, GasNet's Capital Base would be depreciated on the basis of forecast capital expenditure rather than actual capital expenditure.

5.10 Inflation 1998 - 2002

As required by section 8.9 of the Code, GasNet has adjusted the Capital Base for inflation. Consistent with the real rate of return tariff methodology employed by GasNet, the Capital Base has been escalated each year in line with inflation. The impact on the Capital Base is set out in the AA Information.

For the period up to 31 December 2001 GasNet has used actual inflation based on the Consumer Price Index: All Groups, weighted Average of Eight Capital Cities published by the Australian Bureau of Statistics.

For 2002, GasNet has used a forecast annual inflation rate of 2.5%, which is the mid point of the Reserve Bank target range.

6 Rate of return

6.1 Summary of GasNet's Proposals

GasNet's proposals in relation to the Rate of Return apply the well established WACC and CAPM methodologies employed by the Commission and other regulators to derive a real pre-tax WACC of 8.22%.

In relation to the WACC parameters, GasNet proposes amounts that are generally within the range adopted by the Commission in recent regulatory decisions. However, in relation to a number of parameters (such as the equity beta) GasNet proposes marginally higher returns.

(a) This is consistent with GasNet's contention that the WACC is an inherently uncertain estimation (in particular the beta is difficult to determine with great accuracy) and that the long run benefits of infrastructure are promoted by an appropriate return.

(b) In addition, the higher return better reflects the risks resulting from GasNet's unique characteristics, such as:

    (i) the pay-as-you-go market carriage system, which prevents GasNet from securing long term haulage contracts; and

    (ii) the price cap regime, which exposes GasNet to volume risks and which will result in an estimated aggregate revenue shortfall of $19.3 million in the First Access Arrangement Period.

In addition, GasNet proposes a number of minor adjustments to the mechanics of the WACC estimation (for example, the selection of bond rates used to derive the risk free rate).

Finally, GasNet proposes a number of cash flow adjustments to reflect specific asymmetric risks that are not addressed by the CAPM. These are discussed in section 8.7 and Schedule 4 of this Submission.

6.2 Code requirements

Section 8.4(a) of the Code provides that, under a Cost of Service Methodology, the Total Revenue must include *a return (Rate of Return) on the value of the capital assets that form the Covered Pipeline (Capital Base)*.

Section 8.30 of the Code provides that the Rate of Return should provide a return which is commensurate with:

(a) prevailing conditions in the market for funds (presumably including equity and debt); and

(b) the risk involved in delivering the Reference Service.

Section 8.31 of the Code suggests as an example using a weighted average of the return applicable to each source of funds (equity, debt and any other relevant sources of funds) and that such returns may be determined on the basis of a well accepted financial model such as the Capital Asset Pricing Model (CAPM).

Section 8.31 of the Code goes on to provide that in general the weighted average of the returns on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice (although other approaches may be adopted where the relevant Regulator is satisfied to do so would be consistent with the objectives contained in section 8.1 of the Code).

6.3 Approaches to the Rate of Return

The general principles surrounding the concept of the Rate of Return are well established in Australian regulatory jurisprudence and the Commission has a well established position on the form of WACC and the approach to estimating its various parameters.

For example, the Code itself contains principles for determining the Rate of Return which essentially require:

> *a return which is commensurate with the prevailing conditions in the market for funds and the risks involved in delivering the Reference Service.*[21]

Similarly, the ESC has observed that:

> *The cost of capital associated with an asset is the return investors would expect to receive from that project in order to justify committing funds*.[22]

The determination of the Rate of Return presents an inherent tension between providing a sufficient return to investors and preventing the extraction of monopoly rents. The Commission has observed that:

> *It is important that the Rate of Return be set at an appropriate level which reflects a commercial return for the regulated business. Setting a Rate of Return below the cost of funds in the market could make continued investment in developing the network unattractive for the network owner. This might create pressure for the regulated business to reduce maintenance and capital expenditure below optimum levels thus degrading the quality of the service provided. Conversely, if the Rate of Return was set at too high a level by the Regulator, the regulated business would earn a return in excess of its cost of capital. This would distort investment decisions and price signals to consumers and investors, resulting in a misallocation of resources and a sub-optimal economic outcome*.[23]

The return on assets represents the largest single component of the cost of service for the GasNet regulated business, accounting for approximately half

[21] Code, Introduction to Chapter 8.

[22] ORG, *2003 Review of Gas Access Arrangements - Position Paper*, September 2001, p 37.

[23] ACCC, *Draft Statement of Principles for Regulation of Transmission Revenues*, 27 May 1999, p 71.

of the projected Total Revenue. Consequently, the determination of the Rate of Return is the largest single element in the determination of the Reference Tariffs.

6.4 Pro-infrastructure philosophy

6.4.1 *Background*

Although it is often portrayed as a mechanical, even formulaic, process, the estimation of the Rate of Return (or WACC[24]) is inherently uncertain and generally produces a range of values. In reality, it requires an exercise of subjective judgment in order to produce a specific result. In particular:

(a) the WACC is a forward-looking concept which requires an assessment of future cost of funds and future risks and therefore cannot be measured directly in the market;

(b) even the achieved return is difficult to estimate because it is highly variable and subject to exogenous shocks;

(c) the CAPM approach is theory-dependent and involves a range of subjective decisions;

(d) the validity of any CAPM exercise depends on the rigour of the assumptions used; and

(e) a range of practical problems arise in attempting to measure items that are statistically uncertain.

While it may simply be a matter of expression, GasNet submits that there is no single "correct" WACC. As discussed above, GasNet considers the WACC is in fact an inherently uncertain concept and that, in any set of circumstances, there will be a range of possible WACCs and the role of the Commission is to identify this range and then, in the exercise of its regulatory discretion and judgment, select a WACC from within this range.

GasNet considers that, in relation to WACC, it is more appropriate to speak of the *estimation* of a WACC value from available information[25].

6.4.2 *Pro-infrastructure philosophy*

In light of this uncertainty, a key question is the overall approach, or philosophy, that a regulator should adopt in exercising its judgment with respect to the various WACC parameters. In particular, in areas where there is uncertainty or ambiguity, should a regulator lean towards an interpretation that favours a higher return, a lower return or attempts to follow a middle path?

[24] The term "Weighted Average Cost of Capital" (WACC) is often used to describe the Rate of Return, because the Rate of Return reflects a weighted average of the payments to debt providers and the residual flows to equity providers. In this Submission, the expressions "Rate of Return" and "WACC" are used interchangeably.

[25] See for example, *ORG, 2003 Review of Gas Access Arrangements - Position Paper*, September 2001, p 37.

GasNet submits that, in determining the WACC, the Commission should err on the side of favouring a higher return. GasNet submits that this is required both from an economic and legal perspective.

As discussed in section 4.3 of this Submission, it is misleading to characterise this tension as a battle between investors and consumers. Rather, the tension is between the short run benefits to consumers from lower access prices and the long run benefits to consumers in encouraging investments in infrastructure by approving higher prices. As both approaches can be characterised as "pro-consumer", GasNet submits that a better characterisation is that of "anti-infrastructure" or "pro-infrastructure" approaches.

GasNet submits that the "pro-infrastructure" approach is clearly preferable as the welfare benefits of the long run objectives far outweigh the short run benefits of lower prices. The economic benefits of infrastructure investment have been considered by the Productivity Commission in its review of the national access regime. In particular, in its Position Paper in March 2001 the Productivity Commission observed that the positive externalities of infrastructure investments such as pipelines are very large and a failure to encourage investment in this infrastructure will lead to a greater loss to the economy as a whole than any short-term gain from a marginal reduction in (presumed) economic rent to an infrastructure owner[26]. In this context, it is worth noting that gas transmission costs represent only 5-10% of the delivered price of gas. Accordingly, decisions by the Commission in relation to WACC can send significant signals to infrastructure investors while having a minimal impact on end users.

6.4.3 *Code requirements*

In relation to the Rate of Return GasNet stresses the significance of the overarching principle in section 2.24 of the Code that, in applying the Reference Tariff Principles, the Commission must take into account, amongst other things, GasNet's legitimate business interests and investment in the GNS.

Similarly, section 8.1(a) of the Code states that the Reference Tariffs should be designed with a view to provide, amongst other things, the opportunity to earn a stream of revenue that recovers the efficient cost associated with the Reference Service.

Section 8.1(b) of the Code provides that a Reference Tariff Policy should be designed with a view to achieving the replication of the outcome of a competitive market. A "competitive market" is one in which workable competition prevails. It does not mean a market in which competition is so severe that margins and incentives for future investment are minimal.

In fact, it is important to emphasise that in replicating the outcome of a competitive market, long term competition principles should be applied. For example, if profitability in a market were to be squeezed beyond acceptable

[26] Productivity Commission, *Review of the National Access Regime*, Position Paper, March 2001 p xviii.

levels, participants will exit the market, and over the longer term prices will increase.

In other words, it would be artificial and a distortion for a WACC to be at such a level that does not reflect long term outcomes and returns in an environment of workable competition.

6.4.4 *Legal requirements*

In addition, GasNet submits that the Code (and similar legislative and regulatory regimes) are designed to achieve particular public policy objectives by imposing fiscal restraints in addition to any legal restraints which would otherwise apply. In particular, reforms such as the introduction of the Code were felt to be necessary in addition to existing restraints such as the Trade Practices Act prohibitions against misuse of market power.

As a fiscal imposition that overrides the ordinary proprietary rights of an asset owner (ie the freedom to choose who will have access to the asset and the terms of that access), the Code should be interpreted in the same way that courts interpret other fiscal legislation, such as taxation legislation.

It is a well established rule of statutory interpretation that fiscal legislation should be interpreted literally and, if the legislation leaves a doubt as to its meaning, the regulated entity is to be given the benefit of that doubt[27].

On the same basis, courts are reluctant to encroach on the income or property rights of a taxpayer unless the relevant statutory provisions are expressed in clear and unambiguous language[28].

Similarly, as the Code and the Law override the ordinary proprietary rights of the Service Provider (for example, to charge what the market will bear), reference can be made to the principles that are applied in relation to the power to acquire property on just terms under section 51(xxxi) of the Constitution. That constitutional guarantee of just terms is given a liberal construction. It may be said that the determination of a WACC that is a disincentive to further investment is not “just”.

6.5 WACC parameters

Given the universal acceptance of the CAPM model by regulators in Australia, GasNet has expressed its proposal in terms consistent with this model. The development of a WACC within the context of the CAPM model requires the Commission to identify a range for certain parameters and to make assumptions. The key parameters, together with GasNet’s proposals, are set out in Table 6-1:

Table 6-1: WACC Parameters

WACC Parameter	GasNet Proposal
Real risk-free interest rate	3.20%*
Nominal risk-free interest rate	5.78%*

[27] *SA Crate Pty Ltd v South* Australia (1983) 35 SASR 92.

[28] For example, see *Commissioner of Taxation v Westraders Pty Ltd* (1980) 144 CLR 55.

WACC Parameter	GasNet Proposal
Bond Maturity Period	10 years
Prevailing Bond Rates Selection Method	Dates to be agreed *ex ante* with Commission
Expected Inflation	2.5%
Inflation selection period	10 years
Debt margin	120 basis points
Cost of Debt	6.98%
Market risk premium	6.0%
Gearing Ratio	60%
Value of Imputation Credits	50%
Asset beta	0.60
Debt beta	0.06
Equity beta	1.40
Return to Equity	14.19%
Nominal Vanilla WACC	9.86%
Real Vanilla WACC	7.19%
Pre tax real WACC (based on post-tax nominal model with normalisation)	8.22%
Real tax wedge	1.04%

* These amounts are indicative only. The final amounts will be determined by reference to market observations prior to the final decision.

Each of these key parameters is discussed in detail below.

6.6 Risk-free interest rate

6.6.1 *Summary*

The CAPM defines the cost of equity as a linear function of the risk of an investment. In the absence of non-diversifiable risk (ie where the equity beta is zero), the cost of equity is equal to the risk-free rate, which is the expected return on a perfectly secure investment.

The conventional wisdom (and one which has been accepted by the Commission) is to equate the risk-free rate with the return on Commonwealth Government bonds.

As discussed above, the Code requires that the Rate of Return is a forward-looking concept. This suggests the use of the Commonwealth Government bond rate that applies now and for a reasonable period into the future.

In selecting the appropriate risk-free rate, GasNet proposes that the rate be set by reference to:

(a) a period agreed in advance between GasNet and the Commission;

(b) a reference date (being the end of the period agreed between GasNet and the Commission) agreed in advance between GasNet and the Commission; and

(c) 10-year bonds, as these give a more stable and market-reflective result than the 5-year bonds previously used by the Commission.

6.6.2 *Measurement method*

Commonwealth Government bond rates can fluctuate significantly from day to day, even for bonds with maturities of five to ten years. The Commission has previously stated that:

> *Although, in theory, an on-the-day rate is considered the best indication of the opportunity cost of capital at any point in time, the Commission accepts that there is some merit in averaging rates over a short period to abstract from day-to-day market volatility.*[29]

In the past the Commission has approved the 40-day averaging method which effectively smooths out the day-to-day fluctuations, although the month-to-month movements can still be significant.

However, rather than conducting a retrospective analysis of the Commonwealth Government bond rates in the period prior to the final decision[30], GasNet submits that there are advantages in the Commission agreeing in advance with GasNet on the appropriate period and dates to be used, with the outcome of that analysis to be included in the Final Decision. The main advantage of this approach is that it enables the regulated entity to hedge its exposure to interest rate fluctuations on a real-time basis. Under the current model, the regulated entity does not know when the 40-day period runs until after the period has expired, which prevents the regulated entity from seeking real-time hedges.

To prevent any market distortions or "gaming" opportunities, GasNet proposes that this period would be agreed, on a confidential basis, between the Commission and GasNet, but would not be disclosed to the market. This prevents any market participants from seeking to exploit artificial arbitrage opportunities created by knowing, in advance, when GasNet is likely to seek hedges from the market.

6.6.3 *Maturity period*

The selection of the appropriate maturity period for the bond rates has generated considerable controversy. The Commission has indicated a preference for a maturity period which matches the term of the Access Arrangement, which in most cases is five years.[31]

In contrast, State regulators have almost universally selected a 10-year maturity period. Table 6-2 shows a selection of the maturity periods adopted by Australian regulators in recent decisions.

[29] ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p 38

[30] Which is the process adopted in recent Commission decisions such as ACCC, *MAPS Gas Access Arrangement* (Final, 2001).

[31] For example, ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p 38.

Table 6-2: Bond Maturity Periods

Regulator	Decision	Date	Maturity Period
ACCC	Final Decision, TPA and VENCorp Access Arrangement	October 1998	5 years
ORG	Multinet, Westar and Stratus Access Arrangement	October 1998	10 years
IPART	Final Decision, AGL Gas Networks Limited Access Arrangement	July 2000	10 years
ACCC	Draft Decision, East Australian Pipeline Ltd Access Arrangement	December 2000	5 years
ACCC	Draft Decision, Northern Territory Gas Pty Ltd Access Arrangement	May 2001	5 years
OFFGAR	Final Decision, Epic Energy Access Arrangement	June 2001	10 years
ACCC	Final Decision, Moomba to Adelaide Access Arrangement	September 2001	5 years
QCA	Allgas and Envestra Access Arrangement	October 2001	10 years
ACCC	Final Decision, Powerlink Access Arrangement	November 2001	5 years

In addition, GasNet submits that for the purposes of determining equity returns, the maturity term should match the long-term nature of the investment, as suggested by the QCA in its references to Professor Officer[32], and that this supports the selection of a 10-year maturity period.

In its Staff Paper Number 1, the ESC supported the selection of a 10 year maturity period. It noted the opinion of Credit Suisse First Boston that the "*ideal proxy for the risk free rate applicable to the period of the project would be the yield on a default risk-free bond with the same maturity".*[33]

In its conclusions the ESC noted that:

> *"The risk-free rate applied in the CAPM should be consistent with the market risk premium (MRP) also applied in the CAPM. Since the MRP is measured as a margin over the contemporaneous 10 year bond rate, it is necessary to take the current 10 year government bond rate as the risk free rate."*[34]

In addition to these considerations, GasNet also submits that five-year bond rates are undesirable because they show a marked level of volatility over a relatively short period (particularly when contrasted with 10-year bond rates).

[32] Officer, R.(1981), "The Measurement of an Entity's Cost of Capital", *Accounting and Finance*, 21(2), November, cited in QCA, Queensland Gas Distribution Access Arrangement (Final, 2001), Part B, p 211.

[33] ORG, *Weighted Average Cost of Capital for Revenue Determination: Gas Distribution*, Staff Paper Number 1, 28 May 1998, p 12.

[34] ORG, *Weighted Average Cost of Capital for Revenue Determination: Gas Distribution*, Staff Paper Number 1, 28 May 1998, p 22.

For example, the 40-day average of real rates on capital-indexed bonds (Aug 2005 series) declined from 3.51% (8 August 2001) to 3.00% (20 Sept. 2001), which is a 0.5% fall over less than seven weeks. By way of illustration, a difference of 0.6% would lead to a variation of almost 9% on the return on assets[35]. This amounts to a lottery that is divorced from the long-term nature of investment in gas pipelines.

The magnitude of this uncertainty is illustrated by a contrast between two recent regulatory decisions. In the Snowy Hydro transmission assets decision in February 2001, the Commission approved a five-year real risk-free rate of 2.78%[36]. However in the Powerlink transmission decision, the Commission, using the same methodology, derived a real risk-free rate of 3.41% in the Draft Decision in July 2001 and 3.25% in the Final Decision in November 2001[37].

Nominal rates show even higher levels of fluctuation. For example, the 40-day average of five-year bonds has varied by as much as 2% over a 10-month period.

The theory behind the forward-looking CAPM assumes that equity investors are continuously modifying their (nominal dollar) expectations as inflation expectations change and as real bond returns change. Using the Snowy and Powerlink decisions as illustrations, the CAPM model suggests that investors increased their expectation of real returns from a long-term investment by 0.64% over a period of five months[38]. Since the real risk free rate feeds straight through into the WACC returns to both equity and debt, the impact of waiting five months for the draft Snowy Decision would have been to increase the real WACC from 6.45% to 7.09% (a proportionate increase of 10%).

GasNet submits that this is an unrealistic assessment of how expectations are set in the equity market. GasNet submits that equity investors in fact take a longer term view of expected returns and that, for this reason, the 10-year real bond rate gives a more representative estimate of the expectations of investors.

As discussed above, the real risk-free rate (as used to determine the GasNet tariffs) will not be determined until the Final Decision. For the purposes of the draft Access Arrangement and this Submission, GasNet has adopted a nominal risk free rate of 5.78% and a real risk free rate of 3.2%.

6.7 Inflation forecast

Although the inflation forecast is not an explicit WACC parameter, it is an inherent aspect of the nominal risk-free rate and cost of debt parameters and

[35] See section 6.3 of this Submission.

[36] ACCC, *SMHEA Transmission Network Revenue Cap Decision 1999/2000-2003/04*, (Final, 2001), p 23.

[37] ACCC, *Queensland Transmission Network Revenue Cap Decision 2002-2006/7* (Final, 2001), p 28.

[38] ie between the final ACCC, *SMHEA Transmission Network Revenue Cap Decision 1999-2000-2003/04* and the draft ACCC, *Queensland Transmission Network Revenue Cap Decision 2002-2006/7*.

is required in order to convert from the post-tax nominal model to the real, pre-tax WACC used in tariff determination.

The trend in recent regulatory decisions appears to be that regulators use the same duration bonds to calculate the inflation forecast as they use to calculate the risk-free rate.

Consistent with this approach, GasNet proposes to forecast inflation by reference to 10-year bonds.

Market expectations of inflation can be observed in the financial markets as the difference between 10-year nominal and index-linked government bonds. As index-linked bonds have a limited range of issuance dates, it is necessary to interpolate from the available data in order to derive the index-linked bond rate which matches the nominal ten-year bond rates.

As with the risk-free interest rate, GasNet proposes to average the inflation expectations as revealed by Commonwealth Government bonds over the period agreed *ex ante*.

For the purposes of the draft Access Arrangement GasNet has assumed an inflation rate of 2.5%.

6.8 Cost of debt

Unlike the return on equity, the cost of debt is essentially an empirical matter and is observable in the financial market. The conventional method to estimate the cost of debt is to add a debt margin to the risk-free rate[39]. The debt margin can be estimated by consulting with lending institutions in the market.

The cost of debt is related to the credit rating of the company, which can be influenced by a range of external macro and micro-economic factors that can vary from time to time.

The value for the debt margin in GasNet's current Access Arrangement is 120 basis points. GasNet estimates that a company with a 60% gearing[40] and a similar risk profile to GasNet would have an effective credit rating in the range of A- to BBB.

Based on the experience gained from GasNet's recent refinancing, GasNet considers that 120 basis points remains a reasonable estimate of the debt margin for a company with those characteristics.

This is consistent with observed market data. For example, GasNet understands that the debt margin disclosed on the Commonwealth Bank of Australia "Spectrum" service on 21 March 2002 were as follows:

[39] See section 6.6 of this Submission.

[40] See section 6.10 of this Submission.

Entity Rating	Debt Margin (basis points)
A	90
A-	105
BBB+	135
BBB	196

This estimate does not include the fees and charges associated with raising debt. These costs are not related to market risk and have been separately accounted for as a business cost in the Non-Capital Costs category.[41]

Recent decisions by the Commission and other regulators have adopted debt margins between 90 and 155 basis points. Table 6-3 summarises recent debt margins adopted by regulators.

Table 6-3: Debt Margins

Regulator	Decision	Date	Debt margin adopted (basis points)
ACCC	Final Decision, TPA and VENCorp Access Arrangement	1998	120
ORG	Electricity Distribution Price Determination	2000	120
IPART	Final Decision, AGL Gas Networks Limited Access Arrangement	July 2000	90-110
ACCC	Draft Decision, East Australian Pipeline Ltd Access Arrangement	December 2000	120
ACCC	Draft Decision, Northern Territory Gas Access Arrangement	May 2001	120
OFFGAR	Final Decision, Epic Energy Access Arrangement	June 2001	120
ACCC	Final Decision - Moomba to Adelaide Access Arrangement	September 2001	120
QCA	Allgas and Envestra Access Arrangement	October 2001	155
ACCC	Final Decision, Powerlink Access Arrangement	November 2001	120

On balance, GasNet proposes to adopt a debt margin of 120 basis points. GasNet will continue to monitor the capital markets for further evidence of a debt margin in the period leading up to the final determination.

6.9 Market risk premium

The market risk premium is a key element in the determination of the expected cost of equity in a business. The market risk premium is generally defined as the difference between the risk-free rate and the average expected return in the stock market (used as a proxy for the economy as a whole). It

[41] See section 8 of this Submission.

represents the premium required by the market for those investments which have a similar risk profile to the market as a whole.

In order to calculate a forward-looking Rate of Return, it is necessary to estimate the future value of the market risk premium. The standard approach to this is to take a historical view of the premium and assume that this will hold into the future. However, the apparent market risk premium has fluctuated significantly over time and, as a result, it is prudent to smooth the fluctuations of the market risk premium and to review the average behaviour over as long a period as possible (typically 100 years).

The Commission and State regulators have consistently adopted a market risk premium of 6% in recent regulatory decisions. However, the Commission has suggested recently that a market risk premium of around 5% may be more appropriate given the (alleged) downward reassessment of the market risk premium in recent years[42] and has observed that there appears to be sufficient support to suggest that the market risk premium is now unlikely to be above 6%[43].

GasNet submits that it is incorrect to suggest that there has been a decline in the market risk premium. If anything, GasNet submits that the market risk premium is above the 6% adopted in recent regulatory decisions.

GasNet has sought advice on the market risk premium from NECG, whose report is attached to this Submission[44]. NECG has considered the available material and concluded that the consensus view of practitioners in the field is that the historic market risk premium in Australia is in the range of 6.2% to 8.1%.

NECG has also reviewed recent research that suggests that there may have been a decline in the market risk premium and concluded that there is no substantive evidence for a decline in the premium.

NECG has concluded that:

(a) the best estimate of the Australian market risk premium based on historical data is approximately 7.0%; and

(b) the best estimate of a long-horizon market risk premium for Australia based on a comparison with the United States is 7.8%.

A market risk premium of between 6% and 8% has received some support from independent regulators.

For example, in 1998, IPART examined the level of the market risk premium and concluded that there was no evidence to warrant a change from previous estimates[45].

[42] ACCC, *ABDP Gas Access Arrangement* (Draft, 2001), p 60..

[43]ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p 40.

[44] See Annexure 2.

[45] IPART (1998), *The Rate of Return for Electricity Distribution Networks*, Discussion paper, November, p. 16.

More recently, the QCA concluded, in relation to the Allgas and Envestra decision that a market risk premium of 6% was the most appropriate estimate.

The QCA analysis demonstrated that the market risk premium has historically had a reasonably stable value of between 6% to 8%. However, it was the opinion of the QCA that in recent years there had been a reduction in the market risk premium to between 5% to 7%.

At the time of its decision in 2001 the QCA felt that this reduction could be attributed to, amongst other things, a period of low interest rates, low inflation and stabilities in the Australian economy.

With the return of moderate inflation, GasNet submits that the market risk premium is most likely to return to the levels of 6% to 8% that prevailed previously. This is consistent with the view that equity return expectations are more stable than bond rates. Therefore, the negative market premiums experienced during the rapidly fluctuating bond rate periods of the 1970s can be seen as a consequence of the lagged response of the equity market.

There have been a number of other major financial events over the last 30 years, including financial deregulation in 1979 and the introduction of dividend imputation in 1987. However, as noted by the QCA, Officer has argued that imputation is unlikely to have had any significant effect on the market risk premium [46].

For the purposes of the draft Access Arrangement, GasNet has adopted a market risk premium of 6.0%.

6.10 Gearing

The financial structure of a business is determined by the gearing, which is generally expressed as a ratio of total debt to total assets, where (in a regulatory context) total assets is given by the value of the regulatory asset base in any given year.

Under the WACC model, the gearing ratio is a constant each year. The GasNet tariff employs a real Rate of Return model, which implies that the gearing is held constant in real terms. This means that, as the regulatory asset base depreciates each year, the debt level is adjusted to maintain a fixed real proportion of the total assets. In circumstance where inflation is higher than the rate of depreciation, this can mean that additional borrowings may be required in some years in order to maintain the constant gearing ratio[47].

The level of gearing influences the perceived risk of both debt and equity and also the level of taxation through the interest tax shield. However, theory suggests that the level of gearing is not critical provided it is within reasonable bounds that avoid the risk of financial distress.

[46] Officer, R. (1981), "The Measurement of an Entity's Cost of Capital", *Accounting and Finance* 21(2), November, cited in QCA, *Queensland Gas Distribution Access Arrangement* (Final, 2001), pp 214 - 218.

[47] This represents an additional cost which should be reflected in GasNet's return. See sections 6.14 and 8.7 of this Submission.

The current Access Arrangement assumes a gearing ratio of 60%, which is the ratio that has been generally accepted by the Commission and State regulators in regulatory determinations.

GasNet proposes, for the purposes of the WACC estimation, to continue to employ a 60% gearing ratio.

6.11 Imputation credits

Dividend imputation (also called franking credits) was introduced in Australia in 1987. Dividend imputation removes the double taxation of shareholder returns by allowing shareholders of a company to utilise franking credits (reflecting the tax that has already been paid at the company level) to offset tax payable on other income. The scheme applies only to Australian shareholders.

The CAPM adopted by the Commission and other Australian regulators is modified by including a gamma in the WACC estimation to reflect the return to shareholders of tax credits associated with their share dividends.

The value of an imputation credit is not directly observable in the market and can only be inferred by a combination of theory and indirect observation. The value of an imputation credit is affected by a number of factors, such as the extent to which dividends are withheld or paid out and the extent to which they can be utilised by shareholders.

The value of imputation credits is generally regarded as being below the cost of the tax paid on company profits. The ratio of actual value to potential value is referred to as the gamma.

In recent regulatory decisions, the value of gamma has been estimated at between 0.3[48] and 0.5[49]. These decisions have been influenced by the research of Hathaway and Officer who came to the conclusion in 1995 that gamma was most likely to have a value of 0.5[50].

GasNet has sought the advice of NECG on this issue. The NECG report, which is provided as an attachment to this Submission, concludes that the best estimate of gamma is 0.5.

There have been a number of recent changes to the tax system which the Commission has indicated might lead to a re-evaluation of gamma[51]. However, it is NECG's opinion that there is no cause to alter the previous assessments.

Based on advice from NECG, GasNet proposes to adopt a gamma of 0.5.

[48] IPART, *NSW Natural Gas System Access Arrangement* (Final, 2000), p 67.

[49] See, for example, ACCC, *ABDP Gas Access Arrangement* (Draft, 2001), p 62.

[50] See, for example, QCA, *Queensland Gas Distribution Access Arrangement* (Final, 2001), p 236.

[51] ACCC, *Queensland Transmission Network Revenue Cap Decision 2002-2006/7* (Final, 2001), p 21.

6.12 Effective tax rate and accelerated depreciation

6.12.1 *GasNet's proposal*

The Reference Tariffs for the First Access Arrangement Period included an allowance for tax calculated without reference to the effects of accelerated depreciation. However, in recent decisions, the Commission has indicated a preference for recognising accelerated depreciation.

Using the Commission's published model (apart from the treatment of accelerated depreciation), GasNet has calculated an effective tax rate and included in its cost of service requirements the corresponding normalised tax allowance (also called the tax wedge). The principal assumptions in this calculation are:

(a) a corporate tax rate of 30%; and

(b) no recognition of accelerated depreciation. For the reasons discussed below, GasNet submits that GasNet's investors should retain the benefits of accelerated depreciation.

In addition, GasNet submits that the Commission should not revisit its approval of the current tariffs (for example, by suggesting that the regulatory asset base be written down by amounts related to a pre-payment of taxation liabilities).

6.12.2 *Background*

The current corporate tax rate is 30%. However, where infrastructure has been installed prior to 2000, the owner of the infrastructure is permitted to accelerate depreciation for taxation purposes resulting in an excess depreciation allowance for tax in the early years of a project, and a considerable deferral (or back-ending) of any tax liabilities associated with the project. The deferral of these liabilities improves initial cashflows and reduces the net present value of the tax payable with respect to the project.

In the MAPS Final Decision, the Commission expressed the view that this issue was resolved by the use of a post-tax WACC regime. In particular, the Commission observed that:

> *This issue becomes irrelevant in the post-tax regulatory framework adopted by the Commission, as taxes are calculated on an "as you go" basis. This involves using a post-tax WACC directly available from CAPM estimates to reflect the return on assets and to capture the impact of taxes in the cashflows. Such taxes are simply added, along with other capital costs and operations and maintenance costs, to calculate the target revenue requirement for the business. This approach avoids the need for a special conversion formula and handles tax in a very transparent way*[52].

The Commission went on to conclude that:

[52] ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p 43.

As the post-tax approach provides full compensation for actual tax liabilities as they occur, it avoids the need to calculate a long-term effective tax rate and problems generated by post-tax returns diverging from market rates over time. As far as the business is concerned, the post-tax approach would remove any risks associated with future tax liabilities and provide a return always commensurate with market requirements[53].

This treatment of accelerated depreciation implicitly passes through the full benefit of accelerated depreciation to consumers.

However, GasNet submits that the benefit of accelerated depreciation should be retained by GasNet because this retention:

(a) is consistent with the policy objectives of accelerated depreciation;

(b) reflects the behaviour of a competitive market for the benefit of accelerated depreciation to be retained by the asset owner in the form of a higher return, rather than passed through to the users of the infrastructure; and

(c) is required for consistency with the Commission's 1998 Victorian Gas decisions.

6.12.3 *Policy objectives of accelerated depreciation*

GasNet has sought advice from NECG in relation to the policy objectives behind, and the operation of, accelerated depreciation. A copy of the NECG report is attached to this Submission[54].

As discussed in the NECG report, the intention of the Commonwealth Government in allowing accelerated depreciation of long-lived assets for tax purposes was to encourage investment in those assets. The aim of the Commonwealth Government was to divert the funds which would otherwise have been invested in other assets or in overseas investments. This policy was consistent with the widely held view that investment in infrastructure should be encouraged because long-lived infrastructure assets have significant positive externalities.[55]

GasNet submits that a key policy objective of the Commonwealth Government in the introduction of accelerated depreciation was the pursuit of these positive externalities.

As set out in the NECG report, NECG has concluded that there is a reasonable basis to believe that the Commonwealth Government intended that the NPV benefit of accelerated depreciation should be retained by the company in the form of a higher return, rather than passed through to the users of the infrastructure.

[53] ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p 43.

[54] See Annexure 3.

[55] See section 4.3 of this Submission.

As discussed above, the purpose of the Code is to reflect long term competitive outcomes and the retention of the accelerated depreciation benefit is consistent with this.

Therefore, GasNet submits that accelerated depreciation should be ignored for the purposes of calculating the regulatory returns for a business such as GasNet. That is, the returns should be calculated assuming a tax depreciation profile equal to the economic depreciation of the asset. To do otherwise would deprive GasNet of the benefit of accelerated depreciation, which would be contrary to the policy objective of the Commonwealth Government in relation to accelerated depreciation.

6.12.4 *Consequences of the 1998 decision*

The Commission accepted, as part of the approval of the current GasNet Access Arrangement, that GasNet should be able to retain the benefits of accelerated depreciation. In that decision, the Commission approved a pre-tax WACC regime which assumed an effective tax rate set at the corporate tax rate. The Commission noted that to attempt to incorporate accelerated depreciation into the effective tax rate introduced considerable uncertainty beyond a short time horizon, particularly as tax calculations are sensitive to assumptions regarding maintenance of the effective tax regime, inflation and the depreciable value of the assets for tax purposes[56].

However, the Commission observed that there was some resistance to this approach and that the issue required further investigation by the Commission[57].

GasNet submits that the reservations which the Commission expressed in 1998 are equally valid today. In particular, attempting to allow for accelerated depreciation introduces a number of critical uncertainties for the regulated entity. For instance, although the Commission has asserted in recent decisions that its post-tax nominal WACC removes risk for the regulated entity, this risk is only removed over the life of the asset[58]. However, this introduces considerable uncertainty for the regulated entity as it assumes that the regulated entity will enjoy, for the life of the asset, a constant:

(a) tax regime;

(b) inflation rate;

(c) depreciable asset value; and

(d) regulatory regime.

In addition, GasNet submits that, if the Commission decided to move from a WACC regime which ignored the effects of accelerated depreciation to a regime which sought to pass through the full effects of accelerated

[56] ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998), p 46.

[57] ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998), p 46.

[58] ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p 43.

depreciation to users, then this would represent an unacceptable regulatory inconsistency.

As a general rule, regulated entities are entitled to assume that regulators will, given similar circumstances, exercise their discretions in a similar way. Regulated entities (and their shareholders) are entitled to act in reliance on this assumption and a regulator should be extremely reluctant to change the way it treats particular regulatory discretions in relation to each regulated entity.

This issue is exacerbated in relation to GasNet by the statements which the Commission made as part of the 1998 decision. In that decision, the Commission observed, in relation to its decision to assume that depreciation for tax purposes is identical to economic depreciation (ie excluding the effect of accelerated depreciation), that:

> *If concessions were reflected in the cashflows, the return on equity implied by a 7.75 per cent real pre-tax WACC is 14.7 per cent. While the business might be expected to achieve this return, the benefit will basically accrue to the Victorian Government in the form of a higher sale price*[59].

By this observation, the Commission sent the unambiguous message that it expected the business to retain the benefits associated with accelerated depreciation and, more importantly, that the new owner would, as part of the privatisation process, increase its purchase price to reflect the value of this benefit.

Given the unequivocal nature of this statement by the Commission, the investors in GasNet are entitled to rely on this statement and the Commission should not resile from this statement, even if it has, on a bona fide basis, concluded that an alternative regulatory treatment is now appropriate.

6.13 Equity beta

6.13.1 *GasNet's proposal*

GasNet proposes to adopt an asset beta of 0.60 and a debt beta of 0.06. Using the Monkhouse formula, this gives an equity beta of 1.40.

Although this asset beta is higher than that approved in recent decisions (for example, the asset beta of 0.5 approved in the Commission's MAPS decision), it is justified by the unique circumstances of GasNet. In particular, the market carriage regime and the price cap tariff methodology mean that GasNet's revenues are very sensitive to changes in GDP (in comparison to other regulated gas and electricity companies).

6.13.2 *General*

The risks faced by business can be described as either systematic (non-diversifiable) or non-systematic (diversifiable).

[59] ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998), p 53.

The CAPM incorporates an allowance for systematic risk through the equity beta, which is a statistical measure of the riskiness of the asset relative to the whole market. Systematic risk is risk that cannot be mitigated through a diversified portfolio. It is measured with respect to the financial market as a whole and an equity beta of less than 1 indicates that a stock has a lower systematic risk relative to the market as a whole.

Non-systematic risks are specific or unique to an asset and may include risks such as asset stranding, bad weather and operations risk. Non-systematic risks can be reduced through a diversified portfolio and, as a result, are not reflected in the equity beta parameter of the CAPM.

Systematic risks (and the equity beta) are discussed in this section. Non-systematic risks are discussed in section 8.7 and Schedule 4 of this Submission.

6.13.3 *Estimating an equity beta*

In theory, an equity beta can be estimated from observations in the market, by correlating the returns of particular companies with the returns of the stock market as a whole. However, an observed equity beta is difficult to achieve as it requires various smoothing devices to accommodate statistical fluctuations and, in the case of GasNet, there is insufficient history to make such an estimate.

In the absence of company-specific information, the general practice is to utilise observations of a group of comparable companies. However, these financial parameters are country-specific and, in Australia, it is difficult to obtain a reasonably representative sample of companies with a sufficiently long series of observations. Therefore, the equity beta is yet another component of the WACC estimate which requires careful judgment by the Commission.

The Commission has previously recognised a degree of higher risk that applies to GasNet in comparison to other pipeline companies around Australia, as evidenced by the higher equity beta assigned to GasNet in comparison to other gas transmission companies[60].

In preparation for the revisions to the Access Arrangement, GasNet sought advice from NECG in relation to the equity beta (including the asset and debt beta) factors to be employed in the CAPM. The NECG report is attached to this Submission[61].

6.13.4 *Asset beta*

Gearing increases the equity beta of a company by adding financial risk to the normal market and operating risks. Two companies with the same market risk profile but with different levels of gearing will have different equity betas. In order to permit meaningful comparisons of betas between

[60] In ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998), the Commission approved an equity beta of 1.20 for GasNet, which was marginally higher than the equity betas of 1.16 subsequently approved for the Moomba-Sydney pipeline and the Moomba-Adelaide pipeline.

[61] See Annexure 6.

companies, it is usual practice to convert from an equity beta to an "asset beta", which is the beta that would apply if the company was financed with 100% equity. This enables comparison across companies with different gearing structures.

As discussed in the NECG report, practitioners use a number of formulae to lever/delever the equity and asset betas. The Commission has adopted the Monkhouse formula. However, as noted in the NECG report, the choice of formula is not significant provided the formula is used consistently in both the levering and delevering operations.

As discussed above, there is insufficient stock market history for GasNet from which a beta may be estimated.

NECG has undertaken a review of the asset beta for a range of companies similar to GasNet. However, as noted in the NECG report, there are very few companies comparable to GasNet which would provide a meaningful guide as to the appropriate beta and those companies for which data is available may not have a sufficient financial history to enable an accurate determination of their individual betas.

NECG has identified a number of distinctive factors relating to GasNet (in comparison to other gas and electricity transmission and distribution companies) which indicate that GasNet's volumes (and, correspondingly, revenues) are very sensitive to changes in GDP (as implied by VENCorp forecasts). This suggests that GasNet's revenues bear a strong correlation to overall market fluctuations, which implies a higher beta. In particular:

(a) GasNet is regulated under a price cap regime, which exposes GasNet to full volume risk (electricity transmission companies, for example, generally operate under a revenue cap which removes volume risk);

(b) the GasNet tariff structure is linear, in contrast to the two-part tariff often used on distribution networks and contract carriage transmission pipelines, which results in GasNet having a greater exposure to volume risks; and

(c) under the Service Envelope Agreement and MSO Rules GasNet is "locked in" to a market carriage regime and does not have significant revenues secured under take or pay contracts, as is the norm on contract carriage gas transmission systems.

As evidenced by GasNet's experience to date, these risks are not mere theoretical niceties, but can have very real effects.

In the Final Decision, the Commission approved an asset beta of 0.55. However, actual events suggest this was understated. For example, in the period from 1 January 1999 to 31 December 2001, GasNet's actual volumes have been consistently lower than forecast. As a result, GasNet's actual revenues have been significantly lower than the revenues implied in the forecasts used to determine the Reference Tariffs. This revenue shortfall is expected to exceed \$19.3 million. By way of example, a typical electricity transmission company without volume risk has an asset beta of 0.4. If this asset beta were to be increased by 0.2 to 0.6, then the revenue impact on an asset base comparable to the GasNet asset base would be approximately $5.5 million per year. This amount would not have compensated GasNet for the actual revenue loss that occurred.

Despite the limitations discussed above, NECG has concluded that an appropriate asset beta for GasNet is in a plausible range of 0.45 to 0.65. Consistent with the pro-infrastructure philosophy described above, GasNet proposes to adopt an asset beta of 0.60.

6.13.5 *Debt beta*

The debt beta is the premium over the risk-free rate for a given proportion of debt funding.

Recent regulatory decisions have adopted a considerable range of values for the debt beta. For example, the Commission has proposed values from 0 to 0.06[62], while the QCA and OffGAR have proposed values of 0.2 to 0.26[63].

NECG has concluded that the value of the debt beta is not critical provided that the same value is used consistently in the delevering formula which converts an equity beta to an asset beta.

Based on previous Commission decisions, GasNet proposes to adopt a debt beta value of 0.06.

6.14 Specific risks

This issue has been the subject of growing focus in recent regulatory decisions. The key questions to be resolved are:

(a) the extent (if any) to which specific risks should be accommodated in the regulated tariffs; and

(b) if an allowance should be made, the mechanism by which that should be achieved.

As discussed above, the CAPM does not provide for non-systematic (or specific) risks. However, consistency with the CAPM framework requires that, to the extent that they need to be recognised, specific risks should be factored into projected cashflows rather than the cost of capital[64]. For this reason, specific risks are discussed in section 8 (Non-Capital Costs) of this Submission, along with other non-capital costs such as operating and maintenance costs.

[62] See, for example, ACCC, *Queensland Transmission Network Revenue Cap Decision 2002-2006/7* (Final, 2001), p 28 and ACCC, *MAPS Gas Access* Arrangement (Final, 2001), p 52.

[63] OffGAR, *DBNGP Gas Access Arrangement* (Draft 2001), Part B, p 199 and QCA, *Queensland Gas Distribution Access Arrangement* (Final, 2001), p 201.

[64] ACCC, *MAPS Gas Access* Arrangement (Final, 2001), p 45.

7 Other capital elements

7.1 Summary of GasNet's proposals

7.1.1 *Capital Events*

In calculating its revenue requirement, GasNet has, consistent with section 8.4 and 8.20 of the Code, included amounts in respect of three capital events for the period 2003-2007.

7.1.2 *Forecast Capital Expenditure*

GasNet has forecast recoverable capital expenditure of $87.0 million (nominal) for the Second Access Arrangement Period. The main items of capital expenditure are the partial looping of the pipeline between the Brooklyn compressor station and Lara, the Gooding compressor refurbishment and the Lurgi pipeline rehabilitation. Each of these items is discussed in section 7.3 of this Submission.

7.1.3 *Depreciation*

GasNet does not propose to deviate significantly from the depreciation schedule approved by the Commission for the First Access Arrangement Period. However, consistent with section 8.33(c) of the Code, GasNet has reviewed the basis for the calculation of the economic lives of the assets in light of recent information on gas reserves and other relevant events.

7.1.4 *Inflation*

As GasNet has adopted a real rate of return tariff methodology, the Reference Tariffs incorporate an escalation of the Capital Base each year, taking into account depreciation in the preceding year. GasNet has used a forecast annual inflation rate of 2.5%, which GasNet will review when the real and nominal bond rates are finalised.

7.2 Code Requirements

In addition to the roll-forward of the previous Capital Base, the Code describes a number of supplementary components to be included in calculating the total revenue requirement.

(a) Section 8.5A of the Code provides that the Cost of Service Methodology must be applied on a basis that deals with the effects of inflation (see section 7.5 below).

(b) Sections 8.20–8.22 of the Code outline how forecast capital expenditures may be included in the Capital Base (see section 7.3 below).

(c) Section 8.4(b) of the Code requires the calculation to take into account depreciation of the Capital Base (see section 7.4 below).

This methodology must be followed in a manner which is consistent with the fixed principles under the Tariff Order, particularly clause 9.2(a)(3), which relates to the calculation of the Capital Base to be rolled forward in a subsequent Access Arrangement. However, as is submitted in section 5.2.4, the Tariff Order fixed principles and the Code requirements sit together comfortably and do not impose inconsistent requirements.

7.3 Forecast Capital Expenditure

7.3.1 *Code Requirement*

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

If the Commission agrees to Reference Tariffs being determined on the basis of forecast New Facilities Investment, this does not automatically imply that such New Facilities Investment will meet the requirements of section 8.16 of the Code when the Commission considers revisions to an Access Arrangement submitted by a Service Provider. However, the Commission may agree, at the time the New Facilities Investment takes place that it meets the requirements of section 8.16 of the Code. The effect of this is to bind the Commission's decision when the Commission considers revisions to an Access Arrangement submitted by the Service Provider (section 8.21 of the Code).

Section 8.22 of the Code also notes that the Reference Tariff Policy should specify how discrepancies between forecast and actual investment are to be reflected in the Capital Base at the commencement of the next Access Arrangement Period (with this decision to be designed to best meet the objectives of section 8.1 of the Code).

7.3.2 *GasNet's proposal*

The forecast capital expenditure for the Access Arrangement Period is set out in the Table 7-1. An explanation of each of the items identified in Table 7-1 is provided below.

Table 7-1: Estimated Capital Expenditure (nominal $ million)

Year ending 30 June	2003	2004	2005	2006	2007
Brooklyn Loop	-	-	-	-	20.70*
Gooding Compressor refurbishment	-	-	6.49	8.13	7.95
Lurgi pipeline refurbishment	2.05	2.10	1.55	5.83	5.97
City Gate Upgrades[65]	-	2.36	2.53	4.41	-
Wollert Automation	-	1.50	1.82	-	-
Small laterals	1.54	1.58	1.62	1.66	1.70
Maintenance Capex	1.90	1.43	0.51	0.59	1.12
Total	5.49	8.97	14.52	20.62	37.44

* This represents the recoverable portion of the Brooklyn Loop capital expenditure

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

7.3.3 *Brooklyn Loop*

As discussed in section 5.8.3, the construction of the Brooklyn Loop, which was expected to be built in 2000, has been deferred. GasNet now expects to construct a partial looping of the Brooklyn-Corio Pipeline in 2007. The forecast construction cost is $32.4 million (2002 dollars).

As discussed below, GasNet submits that a portion (the Recoverable Portion) of the Brooklyn Loop can be reasonably expected to pass the requirements of section 8.16 of the Code when the expenditure is forecast to occur.

The Brooklyn Loop is an augmentation of the SWP which has been designed to increase the deliverability of the SWP into Melbourne. It consists of a 500 mm pipeline with a length of 36 km which is laid in the easement adjoining the existing Brooklyn to Corio pipeline (the loop will terminate at Paradise Road approximately 11 km from the Lara connection point with the SWP).

The duplication is required as part of an overall project to meet deliverability requirements for the system under the load growth and gas flows forecast over the period to December 2007. The forecast incremental gas demand is expected to be met from gas supplied through the SWP injected from WUGS and other Otway Basin sources.

The current supply capacity into Melbourne from the SWP and Brooklyn to Lara pipelines is 250 TJ/day under realistic operating conditions. The partial looping will expand the capacity of the SWP from 250 TJ/day to approximately 320 TJ/day.[66] As indicated in the VENCorp APR, the full looping of the pipeline to Lara adds significantly more capacity and may be the most sensible option. However, the supply/demand balance show that the system does not require this additional capacity until after 2007.

The incremental revenue associated with the Brooklyn Loop is the additional revenue generated by the higher flows that can be injected at Iona and delivered into Melbourne. These incremental revenues must be calculated at the prevailing (unaugmented) Reference Tariff on the SWP which GasNet has calculated to be 4.0860 $/GJ (2003 dollars), based on a capacity limit of 250 TJ/day. This tariff has then been applied to the additional capacity of the Brooklyn Loop, which is up to an additional 70 TJ/day. The NPV of the incremental revenues earned from the Loop is $20.7 million in 2007. This value is treated as New Facilities Investment for the purposes of calculating the new GasNet tariffs. The remainder of the investment will be treated as a Speculative Investment.

Cost estimates for the project are based on past experience with similar projects and take into account the high rock content on the pipeline route and the significant amount of urban development adjacent to the pipeline route. In addition, the construction will require a disproportionate number of directional drills and associated tie-ins to cross roads, highways, sewers, creeks and rivers. Cost estimates which benchmark at $45,000 per inch/kilometre exceed a typical cross country benchmark. However, as indicated above, there are a number of construction difficulties associated

[66] Annual Planning Review, Victorian Energy Networks Corporation, November 2001, p 32.

with this route. On this basis, GasNet submits that 56% of the forecast capital expenditure on the Brooklyn Loop is reasonably likely to meet the requirements of section 8.16 of the Code when the expenditure is forecast to occur.

7.3.4 *Gooding compressor station refurbishment*

The Gooding compressor station refurbishment is expected to be commissioned over the period 2005-2007 at a cost of $20.3 million (2002 dollars).

The compressor station, which was constructed in 1976, is nearing the end of its 30 year technical life. This life is consistent with the technical life for compressor stations adopted by most other transmission pipeline companies.[67] The current compressors are showing signs of wear and erosion consistent with being in service for nearly 30 years. The station has an operating duty which has subjected the rotating equipment to unusually high levels of thermal cycling associated with a high frequency of stops and starts. In addition, the compressor staging no longer matches the ideal operating point which has moved with changes in sources of supply.[68] GasNet proposes to replace the turbines and compressors with packages optimally staged for future operating needs and incorporating the low emission and dry seal technologies currently available.

The refurbishment of the compressor station is also required:

(a) to replace the ancillary equipment including exhaust systems, air intake housings, back up generator and gas and water jacket heaters which have substantially deteriorated with age;

(b) to add station cooling to sustain longer operating periods through fewer stops and starts; and

(c) to upgrade the PLC control system to ensure compliance with the recently released IEC 61508 standard governing the design of safety systems.

For the reasons identified above, GasNet submits that the capital expenditure is reasonably likely to meet the requirements of section 8.16 of the Code. Cost estimates are based on past experience of similar projects and information from original equipment manufacturers. Cost estimates also take into account the requirement under clause 19(l) of the Environment Policy (Air Quality Management) No. 5240 which requires a generator of a new or substantially modified source of emissions to apply best practice in the management of those emissions.

7.3.5 *Lurgi pipeline rehabilitation*

The Lurgi pipeline rehabilitation is expected to take place over the period 2003 - 2007. The capital works will be staged and the results of each stage will determine the nature of the expenditure for the next stage and hence final

[67] See for example, ACCC, *MAPS Gas Access* Arrangement (Final, 2001), p 20.

[68] See Annual Planning Review, VENCorp Energy Networks Corporation, November 2001, p 20.

project costs will be dependent on the results of pigging and subsequent dig up investigations. The estimated costs for the project range from $5.4 million to $28.9 million depending on the results of the internal inspection.

The Lurgi pipeline was built in 1956 and is the oldest gas transmission pipeline in Australia. The Lurgi line was built in accordance with the available technologies and standards of the day. Pipe manufacturing, coating systems, construction techniques and corrosion mitigation science have since advanced significantly.

GasNet has been unable to undertake any internal inspections of the pipeline to identify evidence of corrosion as the line valves are not designed to enable the passage of a pig. In order to internally inspect this pipeline, it will be necessary to conduct significant works to enable geometric and corrosion pigs to travel the length of the pipeline. Such works include replacing line valves.

The current maximum operating pressure for the Lurgi pipeline is 2760 kPa. Depending on the survey results there is a real possibility that the pipeline, or segments of the pipeline may need to be de-rated to operate at pressures below 1050 kpa. To continue to provide equivalent capacity and service requirements from a de-rated pipeline, significant works will need to be carried out. This work will involve:

(a) building cross connections between the 6890 kPa Longford - Dandenong pipeline and the de-rated 1050 kPa Lurgi pipeline.;

(b) carrying out alterations within the Dandenong terminal station for the supply of gas into the 2760 kPa and 700 kPa systems, currently supplied from the Lurgi pipeline;

(c) building new city gates at Morwell and at the end of each cross connection;

(d) the partial looping of the Longford to Dandenong pipeline; and

(e) substantial replacement or repair of sections of the pipe and/or coating.

The capital works will be staged to ensure that only necessary works will be conducted. The results of each stage will determine the nature of the expenditure for the next stage. Each of the stages and the options for rehabilitating the pipeline are set out below.

(a) Stage 1 - Pipeline is prepared for pigging including the removal/replacement of selected line values. Pigging is conducted in 2005. Results of pigging analysed and verified with a dig up program. The estimated cost of Stage 1 is $4.19 million.

(b) Stage 2 - Rehabilitate the pipeline according to the results of the pigging analysis. Depending on the level of deterioration identified, the three possible options are:

(i) **Option 1**

Rehabilitate the pipeline in its entirety for continued operation at 2760 kPa in 2006 by repairing defects for an estimated cost of $1.25m. This option assumes the achievement of satisfactory pigging results.

(ii) **Option 2**

De-rate the 10.2 km Dandenong to LV1 segment to 1050 kPa and undertake work to compensate for the change, including installing a city gate at LV1, modifying the facilities at the Dandenong terminal station and half looping the Longford to Dandenong pipeline between Drouin and Bunyip.

The estimated cost of works is $9.43 million.

(iii) **Option 3**

De-rate the entire Lurgi line and undertake work to compensate for the change, including the construction of a city gate and a short pipeline to Jeeralang from the Tyers to Morwell pipeline, looping the Longford to Dandenong pipeline as described above, building cross connections between the Longford to Dandenong pipeline and Lurgi pipeline and building heaters and regulators at each cross section.

The estimated cost of works is $24.74 million.

Due to the age of the pipeline and the fact that the pipeline transported manufactured gas for the first 13 years of operation, it is likely that large quantities of sludge and debris are present. The accuracy of the metal loss results will depend on the extent to which the surface of the pipeline can be cleaned. The achievement of conclusive pigging could also be hampered by the fact that older pipelines have variable material permeability and wider wall thickness tolerances.

If pigging results are inconclusive, then GasNet would have to make a determination as to the suitability of the pipeline to continue to operate at 2760 kPa (MOAP). It is likely that such a determination would lead to the adoption of option 2 or 3.

Options 2 and 3 are considered the most cost efficient options available to meet the capacity requirements of a partially or fully de-rated pipeline. Cost estimates are based on past experience with the recent construction of eight city gates and benchmark pipeline costs applicable for short laterals and augmentations. As it is not possible to predict which outcome is most likely, an average of the possible outcomes (that is, $16.0 million (2002 dollars)) has been assumed.

7.3.6 *City gate upgrades*

Upgrades at the Dandenong, Wollert and Morwell city gates and the Tyers pressure limiter will be conducted over the period 2006 to 2007. The forecast cost of the upgrades is $5.3 million (2002 dollars).

These upgrades are necessary for the following reasons.

(a) Most of the regulators and associated controls are over 30 years old and experience frequent hydraulic oil leaks. They are becoming less reliable and more expensive to keep in service.

(b) There are no liquid separation facilities (except at compressor station inlets) throughout the transmission system to separate liquids injected into the transmission system by producers. The liquids are injected in low levels and dropped out of the stream flow and quantities build up over time. GasNet currently conducts periodic line valve syphoning to remove excess liquids from the pipeline low points. With greater diversity of markets and supply sources and the tendency for plants to operate at peak capabilities, higher levels of liquid carryover can be anticipated in the future. Liquid carry over is very difficult to detect using the current technology and gas quality monitoring equipment. Therefore, GasNet proposes to install liquid removal facilities at each of the these stations.

(c) The design and operational requirements of the Wollert city gate have changed a number of times since it was first constructed. Major re-engineering works are required to rationalise and upgrade the equipment and controls for this city gate.

(d) The Tyers pressure limiter is currently a single run station with limited capability to enable routine or emergency breakdown maintenance without isolating supply to downstream of the station.

For the reasons identified above, GasNet submits that the capital expenditure is reasonably likely to meet the requirements of section 8.16 of the Code. Cost estimates are based on past experience with similar projects.

7.3.7 *Wollert compressor station automation*

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

In addition to allowing the reliable remote operation of the system by VENCorp, the automation of the compressor is required for the following reasons.

(a) Due to the poor reliability of the control system, the station currently requires manning for start up, which is not viable in the long term.

(b) Spare parts and product services are becoming more difficult to source leading to unacceptable repair delays.

(c) Market dynamics drive the compression scheduling through a market clearing engine, requiring prompt and reliable unit starting, stopping and variable speed controls.

(d) The uplift penalties associated with system constraint caused by equipment failure means that a greater level of equipment reliability is required.

For the reasons identified above, GasNet submits that the capital expenditure is required to maintain the safety and integrity of the system.

Cost estimates are based on past experience with automations at the Brooklyn and Gooding compressor stations.

7.3.8 *Gas heaters at Dandenong, Wollert and Tyers*

GasNet proposes to install gas heaters at Dandenong in 2003, Wollert in 2004 and Tyers in 2005. The forecast cost of the projects is $3.0 million (2002 dollars).

The *Gas Safety (Gas Quality) Regulations* 1999 (Vic) and VENCorp "Gas Quality Guidelines" were amended in August 2000 to allow for a broader range of gas qualities. This was intended in part, to allow for more supply diversity from new field developments and interstate capacity. A consequence of this change is that there are now higher probabilities that liquid condensates will form with the lower gas temperatures due to the pressure reductions at the pressure regulator stations.

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

There is an increasing trend for producers to inject gas with increased quantities of higher hydrocarbons. The tendency for liquid condensate to form at the current downstream gas temperatures is expected to increase as more producers supply into the system and the current producers supply into more markets. The current winter trend of using rich gas compositions to meet winter supply peaks is likely to increase in the future.

The cost of installing the heating system is based on benchmark costing derived from recent similar projects at Brooklyn and Lara.

For the reasons identified above, GasNet submits that the capital expenditure is reasonably likely to meet the requirements of section 8.16 of the Code.

7.3.9 *Lateral pipelines*

From time to time, GasNet is required to construct small lateral pipelines to service new business or industrial premises. GasNet expects that at least three laterals (at an average cost of $2.5 million each (2002 dollars)) will be constructed during the Second Access Arrangement Period. Accordingly, GasNet has made an allowance of $1.5 million (2002 dollars) for each year of the Second Access Arrangement Period for the construction of laterals.

7.3.10 *Maintenance capex*

GasNet has included an allowance in each regulatory year for maintenance capital expenditure. Total forecast maintenance capital expenditure is $6.5 (2002 dollars) million. This includes IT upgrades (both hardware and software), upgrading of assets such as cathodic protection units, station instruments, electronic systems and heat exchangers and the acquisition of field and workshop equipment.

7.4 Depreciation

7.4.1 *Code Requirement*

Under the Cost of Service Methodology proposed by GasNet, depreciation of the Capital Base over the Second Access Arrangement Period represents one element of the costs used in establishing Reference Tariffs. Sections 8.32 and 8.33 of the Code set out the principles for calculating depreciation. The Depreciation Schedule should be designed:

(a) to result in the Reference Tariff changing over time consistently with the efficient growth of the market for the service provided;

(b) so that depreciation occurs over the economic life of the assets with progressive adjustments to reflect changes in the expected economic life of the assets; and

(c) subject to the capital redundancy provisions (section 8.27 of the Code), so that an asset is to be depreciated only once so that the total accumulated depreciation of an asset will not exceed the value of the asset at the time the asset was first incorporated into the asset base.

7.4.2 *GasNet's Proposal*

GasNet proposes to continue to apply the current cost accounting (CCA) framework for establishing target revenues. Under this framework, the Capital Base is notionally re-valued in line with inflation on an annual basis.

GasNet also proposes to retain a real rate of return approach to setting target revenue. Using the re-valued figures in conjunction with a real rate of return effectively provides the same return over the life of the asset as an unadjusted capital base coupled with a nominal rate of return. However, using a real rate of return provides a more level tariff profile over time than alternative approaches.

The Depreciation Schedule for the First Access Arrangement Period was based on a real straight line depreciation profile. GasNet proposes to retain this profile, except for the SWP which will be levelised over the first 20 years. GasNet submits that adopting a real straight line depreciation profile strikes a reasonable balance between:

(a) a highly front-ended profile (obtained by the application of nominal straight line depreciation) which is less risky to the pipeline company, but which leads to a rapid reduction in tariffs over time; and

(b) a highly back-ended, levelised tariff, which is significantly riskier because it defers capital recovery to an uncertain future.

GasNet does not propose to deviate significantly from the Depreciation Schedules approved by the Commission for the First Access Arrangement Period. However, consistent with section 8.33(c) of the Code, GasNet has reviewed the basis for the calculation of the economic lives of the assets in the light of recent estimates of gas reserves and other relevant events. New pipelines which have been built since the commencement of the First Access Arrangement Period have also been included in the Depreciation Schedule.

The following steps have been taken in determining the Depreciation Schedule.

(a) Select the appropriate categories of assets.

(b) Determine a reasonable technical life for each of the asset categories and, based on the commissioning dates, determine the remaining technical life for each of the asset categories.

(c) Reduce the remaining technical life by the relevant economic factors that can lead to earlier redundancy and hence determine the remaining economic life of each asset group.

7.4.3 *Asset categories and Technical Life*

Table 7-2 shows the defined asset groups and technical lives adopted for each group.

Table 7-2: Assets categories and technical life

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

The asset groups remain unchanged from the First Access Arrangement Period except for a further sub-categorisation of pipeline assets and the inclusion of easements. As discussed in section 5.5.4 of this Submission, the economic life of an easement is the same as the economic life of the pipeline to which the easement relates.

GasNet has reviewed the technical lives of each asset group and has concluded that there is no reason to change the technical lives from the previous estimates which were incorporated into the Reference Tariffs for the First Access Arrangement Period. In addition, GasNet has consulted GHD, who derived the original estimates of the ODRC for GasNet's assets and who advised on the technical life to be used to establish the original economic lives of the assets. GHD have advised that they see no reason to change the original estimates of technical lives for the GasNet assets.

7.4.4 *Economic Life*

Depreciation represents an allowance for a return of the capital invested in the business such that the capital associated with each asset is fully recovered over its lifetime. The Code requires that each asset or group of assets which form part of the Covered Pipeline should be depreciated over the economic life of the assets.

The term *economic life* is not defined in the Code. However, GasNet submits that it is generally accepted to mean the period over which reasonable revenues are likely to be earned from the asset, given normal levels of maintenance and in the absence of any significant level of capital refurbishment.

GasNet commissioned Saturn Resources to review and update the analysis they conducted to derive the estimates of the asset lives used in relation to the First Access Arrangement Period. Saturn's report has been provided to the Commission on a confidential basis. In the First Access Arrangement Period, GasNet's pipeline assets were divided into two distinct groups, the Longford Group (comprising the Longford to Melbourne transmission assets) and the rest of the system (including the WTS), with a different economic life for each group.

Since the start of the First Access Arrangement Period, GasNet has constructed two new pipelines (the Interconnect and the SWP) which have been included in the assessment of the economic lives of GasNet's pipeline assets.

For the purposes of analysing the economic lives of the pipeline assets, GasNet's assets have been grouped into the following elements, made up of:

(a) Longford Group;

(b) South West Transmission Group (consisting of the SWP and the WTS); and

(c) rest of system.

This grouping recognises the relationship of pipelines to the gas reserves. The use of the South West Transmission Group reflects the fact that the use of this system of pipelines will be strongly influenced by the gas developments in the Otway Basin.

The focus of Saturn's report was an analysis of the factors that can affect the ability of the pipeline to earn reasonable revenues in the future. The factors considered by Saturn were:

(a) gas reserves;

(b) bypass risk;

(c) rezoning and forced relocations; and

(d) unexpected and unspecified factors.

The results of Saturn's analysis are shown in Table 7-3 below.

Table 7-3: Saturn Analysis of Economic Life by Pipeline Group

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

The economic lives for the majority of the system are consistent with the estimates made for the First Access Arrangement Period. The SWP is accorded a longer life reflecting the recent construction date and the anticipated long-term value of connection between the metropolitan area and WUGS. GasNet believes that this facility will have an ongoing value despite the bypass risks to the rest of the system. The economic life of the Longford pipeline has been reduced consistent with recent forecasts of the depletion of Bass Strait reserves and the growth in interstate exports.

Non-pipeline assets have shorter technical lives than pipelines. Therefore, the technical life generally sets the economic life of non-pipeline assets. Where the technical life of a non-pipeline asset exceeds the economic life of the pipeline associated with the non-pipeline asset, the life of the non-pipeline asset is bounded.

7.4.5 *Bypass Risks*

One of the factors underlining Saturn's analysis of the economic lives of GasNet's assets was the effect of bypass risks. GasNet has conducted its own analysis of these risks. GasNet's analysis shows that long term load growth can combine with the significant economies of scale in pipeline construction to make it economic to build entirely new supply pipelines from interstate sources to the major load centres in Victoria, effectively bypassing the existing network. Given the significant growth in gas demand forecast in Victoria over the next 20 to 30 years and the anticipated depletion of local sources of supply over that same period, the results of this analysis indicate that it is prudent to depreciate existing and new pipelines over a period that may be significantly shorter than the expected technical life.

An example of this kind of risk has been provided by the potential bypass of the WTS by the Iona to Adelaide pipeline. The WTS would not ordinarily be subject to bypass unless there was a significant increase in load on this system. However, the decision to construct an interconnection between Iona and Adelaide to access currently undeveloped fields, and the coincidence that the proposed pipeline passes close to major loads on the WTS, has placed the WTS at some risk of bypass.

A further example of bypass risk can be demonstrated by the following case study. Consider the situation where:

(a) Bass Strait and the Otway Basin are substantially depleted of gas;

(b) one or more supplies is sourced via Moomba (possibly Carnarvon, Bonaparte, Browse or PNG basins); and

(c) the load in Victoria is 345 PJ per year by 2025 (based on extrapolation of the most recent ABARE forecast),

In these circumstances, it would be economic to construct a pipeline from Moomba in a direct route to Melbourne, a distance of 1100 kilometres. The required diameter for a 15 MPa pipeline would be approximately 42 inches and would cost approximately $1.3 billion. GasNet has calculated that a plausible tariff for this pipeline would be $0.44 per gigajoule.

If existing pipelines were capable of supplying, say, 100 PJ per annum into Victoria, then a lower diameter 36 inch pipeline would suffice at a cost of $1.1 billion. GasNet has calculated that a plausible tariff for the residual 245 GJ per year is $0.54 per gigajoule. Therefore, the opportunity value of the existing long distance pipelines from Moomba to Melbourne is approximately $0.10 per GJ.

On this basis, GasNet submits that, with the anticipated load growth over the next 20 to 30 years and the development of new sources of supply and interconnectors, the outcome can be to significantly devalue existing pipeline investments, irrespective of the remaining technical life of those assets.

In the case of GasNet's network, it is not possible to say which parts of the network are most at risk, since it will depend on the precise route of new interconnectors. Certainly, some pipelines, particularly laterals, will still be required. However, GasNet submits that it is appropriate for a prudent pipeline investor to assume that the economic life of the pipeline will not be as long as the technical life in the present uncertain environment.

7.4.6 *SWP*

The SWP is a new pipeline in competition with other injection pipelines and requires a reasonable tariff in order to encourage growth. Therefore, GasNet proposes to adopt a 50-year economic life and levelised depreciation for the first 20 years. This is discussed further in Schedule 5.11.

7.4.7 *Depreciation Schedule*

Table 7-4 shows the calculated depreciation allowance for each class of asset and the total depreciation allowance that has been included in the Total Revenue. As discussed in section 7.4.2, these figures are based on the existing CCA framework utilising a real rate of return to calculate revenue.

Table 7-4: Depreciation Allowance by Asset Category ($million)

Asset Category	2003	2004	2005	2006	2007
Pipelines	13.7	14.3	14.9	15.6	15.6
Compressors	4.2	4.4	4.8	4.7	4.1
System control facilities	0.9	0.9	1.1	1.2	1.3
Odorisation	0.01	0.01	0.01	0.01	0.01

Asset Category	2003	2004	2005	2006	2007
Gas Quality	0.02	0.02	0.02	0.02	0.02
General land and building	0.2	0.2	0.2	0.2	0.2
Other	0.3	0.2	0.2	0.2	0.2
Total	19.3	20.0	21.2	21.9	21.4

7.5 Inflation: 2003 - 2007

Consistent with section 8.5A of the Code, the Reference Tariffs have been calculated so as to deal with the effects of inflation. As GasNet has adopted a real rate of return tariff methodology, the Reference Tariffs incorporate an escalation of the Capital Base each year, taking into account depreciation in the preceding year. GasNet has applied an annual inflation rate of 2.5%.

8 Non-Capital Costs

8.1 Summary of GasNet's Proposals

GasNet's proposed Transmission Tariffs incorporate the following allowances for the non-capital costs associated with the Tariffed Transmission Service. For illustration, only the 2003 allowances are included.

Table 8-1: Non-capital costs for 2003 ($ nominal million)

Non-capital cost		Allowance
O&M	Pipeline maintenance	5.9
	Compressor maintenance	3.3
General & administrative		8.0
Fuel gas		1.2
Working capital allowance		0.3
Asymmetric risks		0.7
Capital raising costs		2.5

In addition, two items are carried forward from the First Access Arrangement Period being the K-factor carry over ($14.0 million in total) and the benefit sharing allowance ($5.4 million in total after adjustments for increased workload and forecast regulatory fees which were not actually levied).

The allowances for pipeline and compressor maintenance and general and administrative costs are based on GasNet's best estimates and represent:

(a) no change in real terms from the corresponding forecast costs for 2002 approved in the Final Decision, despite a significant increase in pipeline length and installed compressor power, and a $1.1 million increase in insurance premiums; and

(b) as illustrated by the Cap Gemini benchmarking report, compare very favourably with similar pipeline companies in Australia and overseas.

Over the Second Access Arrangement Period, GasNet's operating costs remain relatively flat. However, there are some variations from year to year, particularly in relation to pipeline maintenance costs. As discussed in section 8.3.2 of this Submission, pigging is a major component of pipeline maintenance costs and accounts for the major component of forecast operating cost variations from year to year.

The allowance for fuel gas relates principally to compressor operation, which is beyond GasNet's control. The allowance for compressor fuel is derived from system models and is based on forecast demand and supply profiles.

The return on working capital relates to the passive linepack and equipment inventories.

The K-factor carry-over represents the expected accumulated K-factor adjustment at the end of 2002 resulting from the price control mechanism in the Tariff Order. This represents revenue from the First Access Arrangement Period to which GasNet is entitled but has been prevented from collecting due to the tariff rebalancing constraint.

The benefit sharing allowance reflects a fair sharing of the efficiencies GasNet has been able to achieve in the First Access Arrangement Period. These efficiencies will be available to Users in all subsequent Access Arrangement Periods. GasNet has calculated the NPV of these enduring efficiency gains, and proposes to retain 20% as a fair sharing of these benefits.

The Asymmetric Risk allowance represents a series of asymmetric risks faced by GasNet which are not addressed elsewhere and, if no allowance were made, would be likely to result in GasNet's revenues falling short of its cost of service.

8.2 Non-capital costs

8.2.1 *Code requirements*

The Code (sections 8.36 and 8.37) allows the recovery of all operating, maintenance and other non-capital costs that would be incurred by a prudent Service Provider, acting efficiently and in accordance with good industry practice, in providing the Reference Service.

Attachment A to the Code requires the Service Provider to disclose certain costs in the Access Arrangement Information, unless it would be unduly harmful to the legitimate business interests of the Service Provider. The costs to be disclosed include wages and salaries, contract services including rental equipment, materials and supply, gas used in operations, property taxes and corporate overheads and marketing. Some disaggregation by zones, services or categories of assets is also required.

8.2.2 *GasNet's proposal*

Under the Cost of Service Methodology, GasNet's Total Revenue is calculated on the basis of, amongst other things, *the operating, maintenance and other non-capital costs incurred in providing all services provided by the Covered Pipeline*.[69]

GasNet submits that the plain reading of this requirement is that the Reference Tariffs are calculated so as to provide a recovery of the forecast non-capital costs. This is supported by section 8.37 of the Code, which provides that:

> *A Reference Tariff may provide for the recovery of all Non-Capital Costs (or forecast Non-Capital Costs, as relevant) except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service.*

GasNet submits that the requirement to achieve the lowest sustainable cost of delivering the Reference Service means that maintenance expenditures should be incurred with a balanced view between current and future expenditures. That is, savings on preventative maintenance in one period should not be

[69] Code, section 8.14.

made at the risk of higher expenses in the future if equipment is allowed to fall into disrepair.

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

(a) operating costs;

(b) return on working capital;

(c) K factor carry-over;

(d) benefit sharing allowance;

(e) asymmetric risk allowance; and

(f) capital raising costs.

Each category of forecast non-capital costs is discussed below. GasNet submits that these costs do not exceed the level of an efficient and prudent Service Provider in accordance with accepted and good industry practice. In particular:

(a) these costs are consistent with historic levels of GasNet's non-capital costs (see section 8.3 of this Submission);

(b) when compared against benchmark studies of comparable pipeline networks, these costs are reasonable (see section 8.4.5 of this Submission).

8.3 Operating costs

8.3.1 *Components of operating costs*

Operating costs have been divided into the following activity based categories.

(a) Operating and maintenance costs (O&M) which include:

  (i) pipeline maintenance costs (operation and maintenance of pipelines, in-line regulators, heaters and valves, and provision of odorant); and

  (ii) compressor maintenance (operation and maintenance of compressor stations, excluding fuel).

(b) Fuel gas costs (for compressor operations and heaters).

(c) General and administrative costs (G&A).

GasNet's forecast operating costs must be considered within the context of the Market Carriage system operating in Victoria. Under the Service Envelope Agreement, GasNet is required to undertake maintenance in accordance with a maintenance schedule approved by VENCorp. Under the MSO Rules, GasNet is exposed to uplift penalties if a failure of any piece of equipment on the GasNet system leads to a cost incurred in the market that would otherwise not be incurred. This exposure can amount to as much as $1 million per annum.

In addition, there is a relatively small amount of line pack in the system and therefore the failure of a compressor to start or continue to operate can have a significant impact on the market. Accordingly, it is essential that GasNet's compressors and control systems be maintained in good working order. Furthermore, GasNet must maintain a quick response capability to deal with potential equipment failures, as line-pack levels can decline rapidly if a compressor fails.

While there have been significant reductions in staff numbers, there has been very little recruitment of younger staff. This has resulted in the company having a high average age workforce. In addition, the depth of the skill base has been insufficient to ensure continuity of service and there is a high dependence on individuals in critical areas. This is neither prudent nor sustainable. To mitigate this business risk and to ensure that GasNet's future skills requirements will be met, GasNet has recently recruited junior staff, including graduate and trainee engineers, to develop for the future and to provide back up in critical areas. The costs associated with this recruitment program are reflected in the forecast operating costs.

The operating costs forecast covers the expenses (excluding taxes) GasNet expects to incur in making the gas transmission system available to VENCorp in accordance with the Service Envelope Agreement.

The forecast has been prepared in light of the anticipated future demands on the system and with regard to:

(a) technical regulatory requirements (including licences and permits under the *Pipelines Act 1967* (Vic) and the Environment Protection Act 1970 (Vic));

(b) GasNet's obligations under the Service Envelope Agreement;

(c) the GasNet Safety Case under the *Gas Safety Act 2001* (Vic); and

(d) the standards of efficiency indicated by relevant Australian and international benchmarks.

The various components of GasNet's forecast non-capital costs for the period 2003 to 2008 are shown in Table 8-2 below.

Table 8-2: Forecast of GasNet's operating costs, Jan 2003- Dec 2007[70] (nominal $million)

Operating cost	2003	2004	2005	2006	2007
Pipeline	5.9	6.8	6.2	7.4	7.4

[70] The forecast costs set out in Table 8-2 constitute that part of GasNet's operating costs which are relevant to the provision of the regulated service. GasNet also provides a metering service and a LNG service. The costs associated with these services have been separated from the costs associated with the regulated service according to a set of transparent accounting measures. Unregulated activity costs are confidential to GasNet. However, GasNet has provided the allocation model to the ACCC for their review.

Operating cost	2003	2004	2005	2006	2007
maintenance					
Compressor maintenance	3.3	3.6	3.7	3.7	3.8
G&A	8.0	8.4	8.6	8.9	9.1
Fuel gas	1.2	1.3	1.4	1.6	1.7
Total	18.4	20.1	19.9	21.6	22.0

Excluding reset costs in 2006 and 2007 which are not charged for in this Access Arrangement Period.

Each of these cost categories is considered in greater detail below.

8.3.2 *Pipeline maintenance costs*

These costs cover the activities directly associated with maintaining the GNS (comprising 1,930 kilometres of pipeline) in good operating order. This cost category includes:

(a) pipeline patrol and easement maintenance;

(b) servicing of valves, regulators and heaters;

(c) provision of odorant and servicing of odorant facilities;

(d) corrosion protection services;

(e) licence fees and charges;

(f) a proportion of the costs associated with operation of the computerised asset management systems;

(g) a proportion of the costs associated with engineering and support functions;

(h) a proportion of the costs associated with management of the GasNet Safety Case;

(i) pigging operations on specific pipe segments; and

(j) communication cost associated with pipeline operations.

GasNet has prepared a forecast of pipeline maintenance costs from a detailed analysis of work requirements over each year to 2007. The forecast is shown in Figure 8-1 in real 2003 dollars.

Figure 8-1 below shows the trend in pipeline expenses normalised by length of pipe (in $2003)[71], for the period 1998 to 2007.

[71] The CPI has been adjusted down by 2.5% in 2000 to account for the GST effect on inflation.

Figure 8-1: Pipeline Maintenance/Km

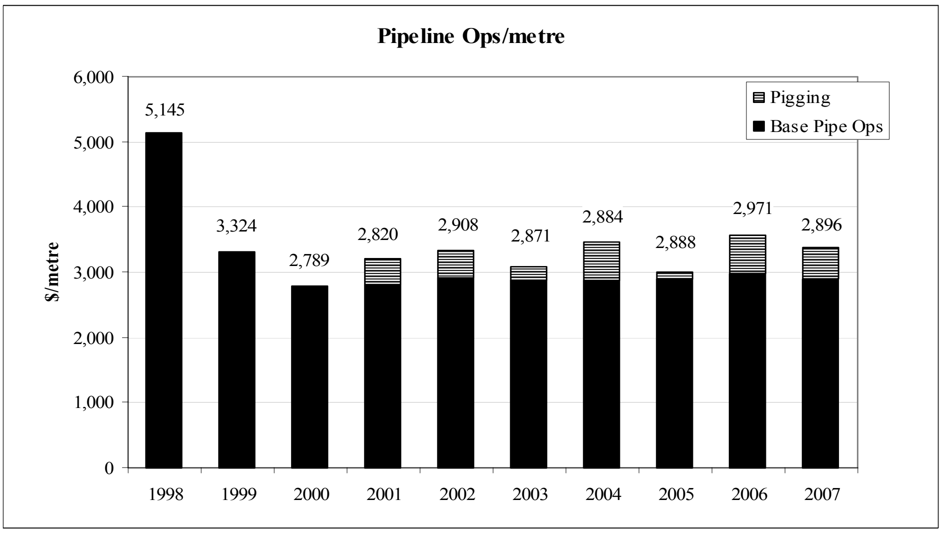


Figure 8-1 shows a significant decline in real normalised operating costs over the current regulatory period which have been brought about by management initiatives to improve efficiency. Those initiatives include:

(a) the adoption of a risk based management of pipeline easements consistent with AS 2885 which has led to significant cost savings through reduced patrol frequencies in low risk passive country areas;

(b) outsourcing of metropolitan daily patrols and inspections and of certain easement maintenance activities;

(c) multi-skilling of personnel, particularly with the use of country based personnel for first response and routine maintenance activities;

(d) the adoption of reliability centred maintenance principles to optimise maintenance tasks and frequencies against business and technical risks;

(e) the rationalisation of engineering and office based operational functions; and

(f) the closure of country depots.

GasNet is not forecasting a significant increase in the length of pipelines over the next regulatory period until the Brooklyn Loop is constructed in 2007. However, with the aging of the pipeline network, GasNet believes it is necessary and prudent to increase the level of pigging operations on a number of the older pipelines in the system.

GasNet considers that the forecast pipeline maintenance costs are prudent. This assessment is based on the results of a benchmarking study[72] and on a comparison of forecast costs with historical normalised costs, after allowing for the additional pipeline maintenance activities.

[72] See section 8.4.5 of this Submission.

8.3.3 *Compressor maintenance costs*

Compressor maintenance costs cover the activities directly associated with providing and maintaining, in good operating order, the facilities at the five compressor stations on the GNS.[73] The cost of compressor fuel is treated separately.

This category of cost covers maintenance of:

(a) gas-fired engines that power the compressors;

(b) compressors, station gas valves, and regulators;

(c) gas coolers including associated water cooling towers;

(d) electronic programmable logic controllers (PLCs) for unit and station controls;

(e) the balance of the plant including back up power generators and ancillary heaters;

(f) the compressor sites, buildings and surrounding areas;

(g) a proportion of the costs associated with the operation of computerised asset management systems;

(h) a proportion of the costs associated with engineering and support functions;

(i) a proportion of the costs associated with management of the GasNet Safety Case; and

(j) communication costs associated with compressor stations.

GasNet has prepared the forecast of compressor maintenance costs from a detailed analysis of work requirements over each year to 2007. The forecast shown in Figure 8-2 is shown in real 2003 dollars.

In making a comparison of costs from one year to the next, it is important to adjust and normalise the costs for the workload undertaken in each year (especially given that over the period 1998 - 2001, GasNet added two compressor stations to the original three). The simplest measure of workload in the case of compressor maintenance is the capital investment in the compressor stations being managed (this reflects the size and complexity of each station and hence the likely maintenance task). The capital investment is determined by the optimised replacement cost (ORC) of each station. For the older stations, this is determined on the basis of the original valuation of the GasNet system undertaken in 1998. For compressors installed since that date, the capital investment has been based on the actual cost.

[73] The costs associated with GasNet's two compressors on the EAPL system are not included.

Figure 8-2: Compressor Maintenance as a percentage of capital investment

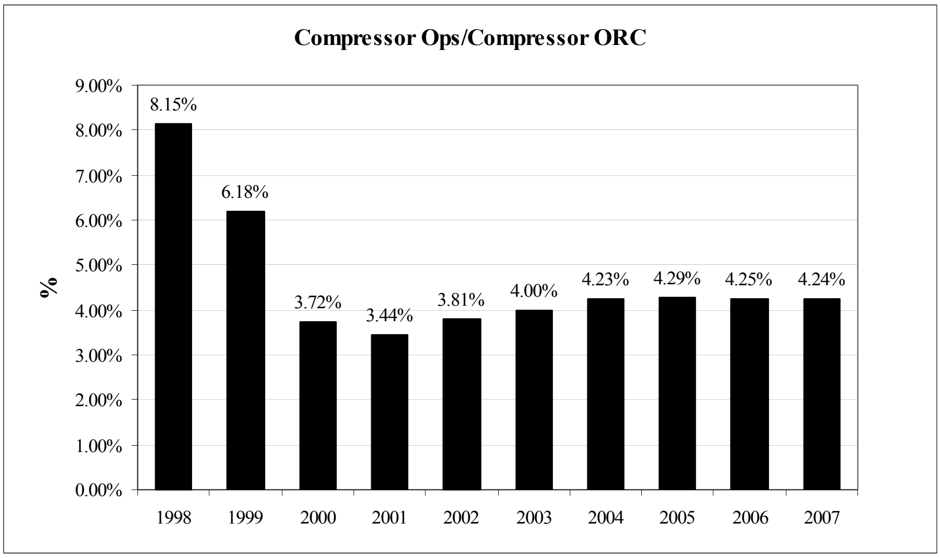


Figure 8-2 shows a significant decline in real operating costs over the current regulatory period, brought about by management initiatives to improve efficiency. These initiatives include:

(a) multi-skilling of personnel, particularly with the use of country based personnel for first response and routine maintenance activities; and

(b) the adoption of reliability centred maintenance principles to optimise maintenance tasks and frequencies against business and technical risk.

GasNet is not forecasting the construction of any new compressor stations over the next regulatory period. However, the forecast includes:

(a) a prudent allowance for random failure of rotating equipment (an indication of the potential impact was a failure of a turbine blade on a Brooklyn Centaur unit which necessitated a premature overhaul of the engine in 2000 for an approximate cost of $400,000);

(b) the increasing costs of technical compliance (for example, the standards of maintenance and the associated field documentation to support compliance with technical regulatory requirements is increasing as evidenced by the recent publication of IEC61508 for control of electronic control systems); and

(c) the proportionally higher operating costs associated with:

  (i) running the Iona compressor station due to the remoteness of its location and the reciprocating technology in use; and

  (ii) the significant increase in the frequency of starts and stops at the Brooklyn compressor station and the associated reduction in service life of the rotating equipment.

GasNet considers that the forecast compressor maintenance costs are prudent. This assessment is based on the results of the benchmarking study[74] and on a comparison of forecast costs with historical forecast costs, after making a prudent allowance for additional expected costs.

8.3.4 *General and Administrative costs*

This category of costs covers activities not directly related to the pipeline operations and includes:

(a) finance, accounting and treasury;

(b) commercial and marketing;

(c) legal and regulatory expenses;

(d) system planning;

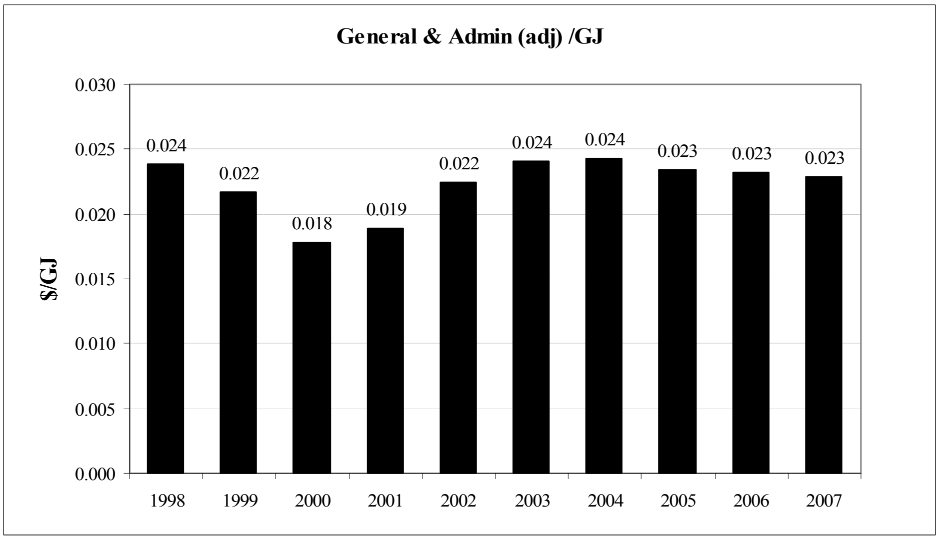
(e) executive management and Board costs; and

(f) stock exchange listing expenses.

As with the other operating costs, it is necessary to normalise the G&A costs for the workload that is undertaken in each year. The consultants engaged to undertake the benchmarking study have made comparisons of G&A expenses between companies by calculating the G&A expense per GJ.

GasNet has calculated the G&A expense per GJ from the commencement of the calculation period to the end of the forecast period in 2007. These normalised costs are shown in Figure 8-3 below. The forecast costs exclude the exceptional costs shown in Table 8-3 below.

Figure 8-3: Adjusted G&A/GJ



[74] See section 8.4.5 of this Submission.

Figure 8-3 shows relatively little change over the historical and forecast periods, save for a significant reduction in costs in 2000 and 2001. This reduction was initiated as a direct response to the dramatic reduction in GasNet revenues in 1999, resulting from the exceptionally warm winter in that year. In practical terms, the reduction was achieved through reduced levels of administrative support, delays in filling vacant positions (in particular, the chief financial officer, a back-up system planner and a business development manager) and lower levels of business development and marketing. These measures were temporary and not sustainable on an on-going basis. GasNet is not forecasting any significant change in G&A costs in the next regulatory period beyond the exceptional costs shown below.

The forecast includes an allowance of $0.4 million to expand GasNet's general marketing activities. GasNet is exposed to volume risk as is evident from actual experience over the past three years, and therefore it is important that GasNet promotes growth in gas volumes. While other participants in the gas industry have an incentive to market gas (for example, retailers), this incentive is not as strong as it is for GasNet. In particular retailers only earn a small margin on the total revenues from delivering gas to consumers, whereas GasNet retains the full revenues from any additional volumes flowed (and vice versa, GasNet can lose the full revenues if forecast growth fails to eventuate). In addition, the three principal retailers in Victoria (Origin, TXU and Pulse) also market electricity hence there is less incentive for them to market gas over electricity.

GasNet believes that gas marketing has diminished in importance since the reforms to the industry, which may party be due to the fact that volume risk has been pushed upstream from retailers to the asset owners. Therefore, GasNet now believes that it must provide a supportive role in the marketing of gas, particularly to large-use applications such as cogeneration, power station developments and other large-scale industrial uses. To this end, GasNet appointed a business development manager in 2001 as part of its strategy to develop marketing activities over the next 5 years.

There are also a number of exceptional costs which must be taken into account when assessing GasNet's G&A costs. These costs include:

(a) ongoing litigation expenses arising from the Longford fire and explosion in 1998;

(b) Listing and governance costs (Board and ASX costs from 2002 onwards);

(c) extraordinary increases in insurance costs (the Service Envelope Agreement imposes an obligation on GasNet to insure the transmission system for their full insurable value against damage or destruction and to maintain public liability insurance of $250 million); and

(d) regulatory reset costs.

As indicated above, GasNet is required under the Service Envelope Agreement to insure the transmission system and to maintain public liability insurance. Therefore, GasNet is not in a position to self-insure. GasNet budgeted for insurance costs of $0.3 million. However, actual insurance costs have increased to $1.7 million. Further, GasNet submits that it is unlikely that insurance costs will fall during the next regulatory period. Indeed, there is a real risk they will continue to rise. However, GasNet submits the most efficient solution is to incorporate an allowance based on actual insurance costs coupled with a pass through if costs increase (see section 8.8 of this Submission). The actual insurance cost for 2002 will not be known until after the date of this Submission.

Listing and governance costs includes costs associated with listing on the ASX (which were not incurred prior to 2002 since GasNet was floated at the end of 2001). It also includes Board and other governance costs which were not included in previous budgets, as GasNet's previous owner GPU did not allocate such costs to GasNet.

Table 8-3 shows a break down of these exceptional costs.

Table 8-3: Exceptional costs ($ million)

Cost category	**2002 (Forecast)**	**2003 (Forecast)**	**2004 (Forecast)**	**2005 (Forecast)**	**2006 (Forecast)**	**2007 (Forecast)**
Reset costs	0.5	0	0	0	1.0	0.6
Esso litigation	0.4	0.2	0.2	0.2	0.2	0.2
Increase in Insurance costs	1.4	1.4	1.4	1.4	1.4	1.4
Listing and governance costs	1.2	1.2	1.3	1.3	1.3	1.4
Total	3.5	2.8	2.9	2.9	3.8	3.6

8.3.5 *Fuel Gas Cost*

GasNet must provide gas for compressor operations and must purchase this gas at market rates. However, VENCorp controls the operation of the compressors, which are scheduled on the basis of the output of the market clearing engine. Therefore, GasNet does not have control over the operation of the compressors and should not be accountable for the quantities of gas used.

However, as GasNet procures the gas for compressor operations from the market, it has provided a forecast of compressor usage. This forecast is based on the forecast injection and withdrawal volumes described in section 9.6 of this Submission. These forecasts have been used in conjunction with the GasNet system planning model to derive the volumes required by each compressor station in each year of the Second Access Arrangement Period.

The forecast compressor fuel costs together with the actual costs from the start of the First Access Arrangement Period are shown in Table 8-4.

Table 8-4: Historical and forecast compressor fuel costs ($ million)

1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
1.0	0.7	0.6	0.9	1.1	1.2	1.3	1.4	1.6	1.7

The forecast fuel costs show a steady increase as demand on the system grows. Some of the historical costs show lower levels of fuel use than was expected due to the exceptionally warm winters when overall demand was low. High compressor usage occurs when system demand exceeds 700 TJ/day. Therefore an exceptionally warm winter will have a disproportionate impact on compressor fuel use.

8.3.6 *Return on working capital*

GasNet proposes a working capital allowance reflecting the costs of:

(a) investment in passive linepack gas (this gas is required in order to keep the pipeline pressurised and available for service); and

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

In section 3.6.2 of the Final Decision, the Commission approved a return on net working capital of approximately $600,000 per annum. However, in recent decisions, the Commission has indicated a reluctance to include any allowance for working capital on debtors and creditors.

GasNet accepts this proposition and has omitted from its working capital allowance any amounts reflecting average debtors and creditors. GasNet submits that the two items in relation to which it is seeking an allowance reflect genuine costs which are not otherwise reflected or offset in the Reference Tariff.

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

Table 8-5 shows the cost associated with each of these items and the forecast return on working capital for the period 2003 to 2007.

Table 8-5: Forecast return on working capital ($ million) (nominal)

	2003	**2004**	**2005**	**2006**	**2007**
Return on linepack	0.2	0.2	0.2	0.2	0.2
Return on inventories	0.1	0.1	0.1	0.1	0.1
Total	0.3	0.3	0.3	0.3	0.3

8.4 Key performance indicators - operating costs

8.4.1 *Code requirements*

Category 6 of Attachment A of the Code includes a requirement that KPIs be included in the access arrangement information. The Code cites two examples of these KPIs.

(a) Industry KPIs used by the Service Provider to justify "reasonably incurred" costs.

(b) The Service Provider's KPIs for each pricing zone, service or category of asset.

Section 8.6 of the Code provides that the Regulator may have regard to any financial and operational performance indicators it considers relevant to determine the level of costs within the range of feasible outcomes under section 8.4 (total revenue) of the Code that is most consistent with the objectives contained in section 8.1 of the Code.

8.4.2 *GasNet's proposal*

GasNet has adopted the following methods to demonstrate that its forecast operating costs are prudent.

(a) Firstly, GasNet's forecast operating costs have been compared against a range of statistics collected from published data of other Australian pipeline companies.

(b) Secondly, GasNet has commissioned a benchmarking report from international consulting firm Cap Gemini which compares GasNet's operating costs with a wide range of Australian and overseas pipeline companies.

8.4.3 *KPI's concepts and qualifications*

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

Working capital costs have been excluded from the KPI statistics as they are unique to each pipeline company and are relatively small in magnitude.[75]

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

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

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

[75] GasNet's treatment of working capital costs is discussed in section 8.3.6 of this Submission.

insurance cost (discussed in section 8.3.4 of this Submission) has also been excluded for the purposes of inter-company comparisons.

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

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

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

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

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

8.4.4 *KPIs*

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

(a) Operating costs per GJ of gas delivered;

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

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

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

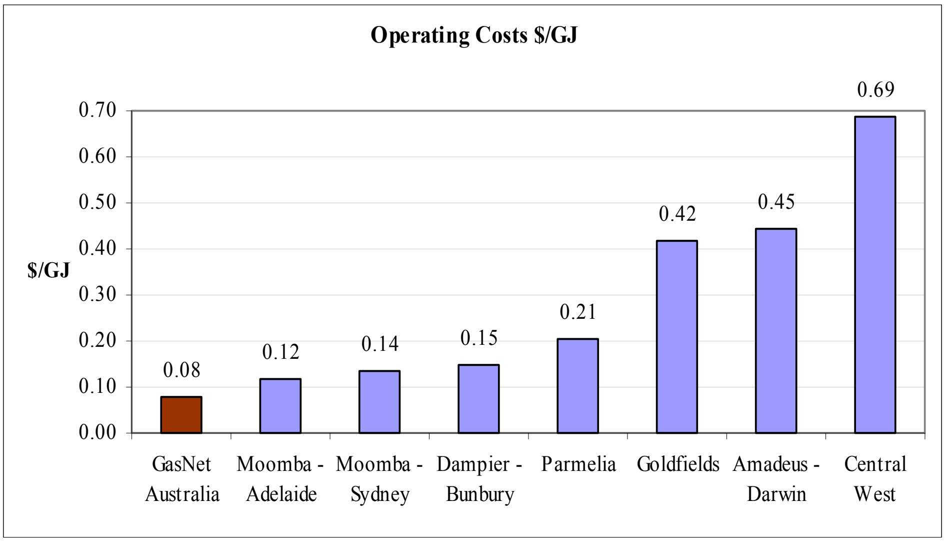
(e) O&M costs as a percentage of the capital investment.

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

Operating costs per GJ of gas delivered

Gas deliveries is the simplest measure of the output of a transmission company. Figure 8-4 below illustrates that on this broad measure of efficiency, GasNet is one of the leading companies.

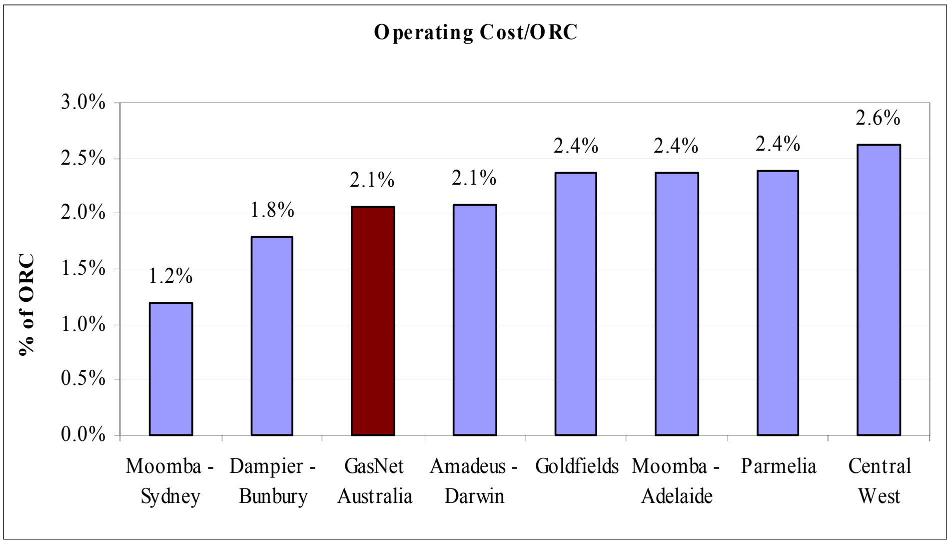
Figure 8-4: Operating costs per GJ delivered



Operating costs as a % of capital investment

Another measure of efficiency is operating costs as a percentage of capital investment. This measure capture both the length of the pipeline system, and the number and size of the compressor stations installed. As indicated in Figure 8-5 below. GasNet performs well in relation to other Australian pipeline companies on this measure.

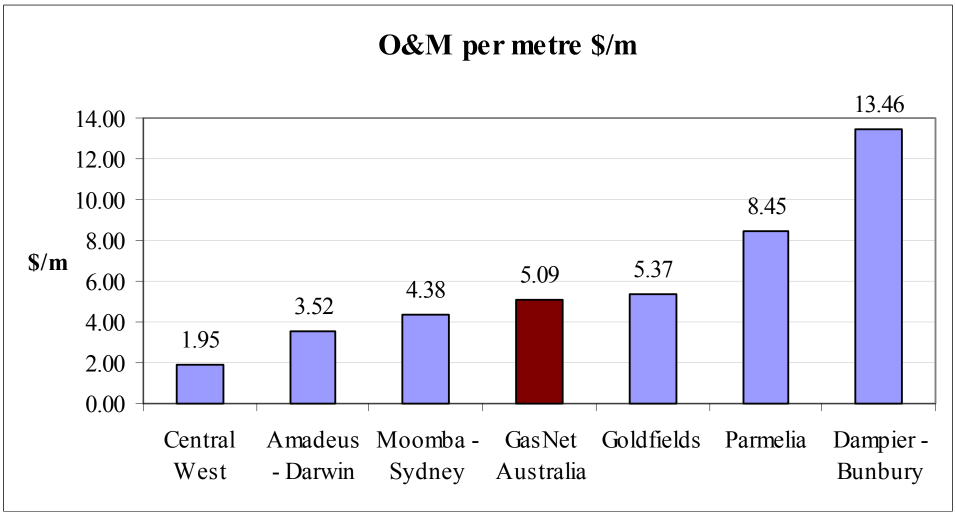
Figure 8-5: Operating Cost/Capital Investment



O&M costs per metre of pipeline

One of the simplest measures of O&M efficiency is cost per metre of pipeline. Figure 8-6 below shows that, on this measure, GasNet sits in the mid range of the scale. One of the reasons that GasNet has higher costs is that it operates a higher number of compressor stations (ie five) each with multiple compressors installed, and therefore incurs higher compressor maintenance costs (which is a major component of O&M costs). In addition, GasNet has a higher percentage of its pipelines located in urban and intensive farming areas where the cost of owning and maintaining pipelines is considerably higher than in less developed areas.

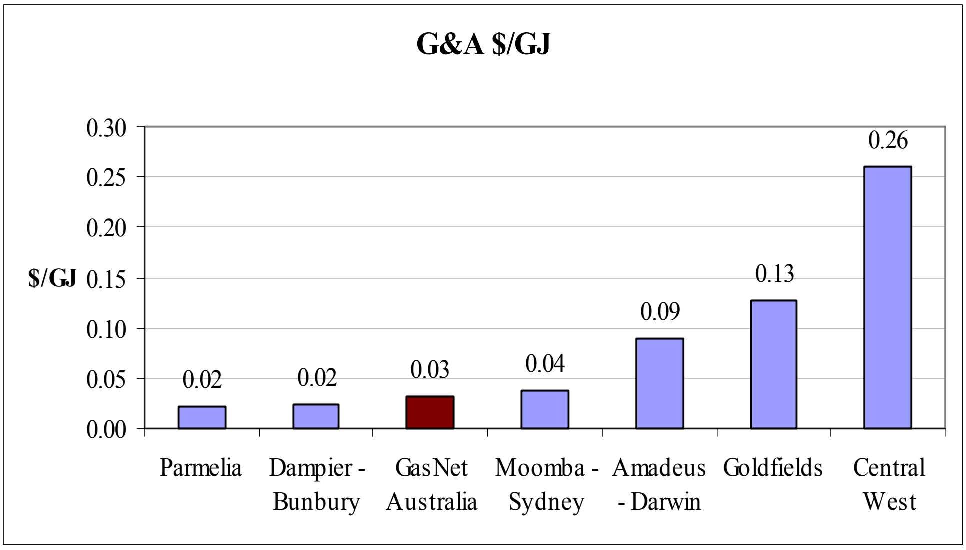
Figure 8-6: O&M costs per metre of pipeline



G&A costs per GJ of gas delivered

G&A expenses are unlikely to be related to the distance the gas travels. A more appropriate measure is gas volumes delivered. Figure 8-7 below illustrates that, on this measure, GasNet performs very well in comparison to other Australian pipeline companies. This conclusion is also supported by the information contained in the Benchmarking Report (see section 8.5.4 of this Submission).

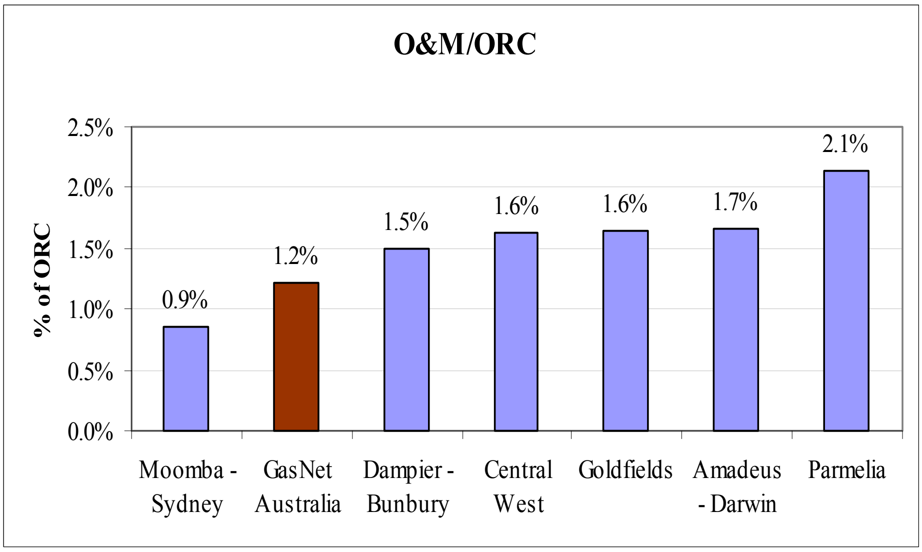
Figure 8-7: G&A costs per GJ delivered



O&M costs as a percentage of capital investment

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

Figure 8-8: O&M costs as a percentage of capital investment



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

Compressor costs as a percentage of capital investment

The Commission has previously cited AGA studies which suggests that compressor maintenance costs would be typically between 3% and 6% of the capital investment in the compressors.[76] GasNet has calculated its compressor maintenance costs to be between 3.5% and 4.0% of capital investment. This puts GasNet at the lower end of the range indicated in the AGA report.

8.4.5 *Benchmarking Report*

GasNet has commissioned a detailed Benchmarking Report from international consultants Cap Gemini. The report contains confidential data from GasNet and from a wide sample of Australian and international gas transmission companies. The report has been provided to the Commission on a confidential basis.

The study is based on GasNet's actual operating results for the year 2000 and also includes historical 1999 and projected year 2001 results. The sample consists of 24 companies from Australia, Canada, USA and South America.

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

The study compares GasNet's results against four specific "peer group" companies, as well as against the results of all 24 participating companies.

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

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

(b) pipeline maintenance expenses; and

(c) compressor maintenance expenses.

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

G&A expenses

The Benchmarking Report concluded that GasNet's overall G&A expenses per million cubic metres delivered were 55% lower than the average of the peer group. GasNet's unit costs fell very close to the lowest or best quartile of all participating companies. Figure 9-1 in Schedule 9 compares GasNet's total G&A costs per million cubic metres of gas delivered to the other companies in the sample.

Pipeline maintenance expenses per pipeline kilometre

The Benchmarking Report analysed pipeline maintenance expenses on the basis of the length of the pipeline system. The Benchmarking Report indicates that this is lower than the peer group average and the all company median. Figure 9-2 in Schedule 9 compares GasNet's pipeline maintenance expenses per kilometre with those of the other companies in the sample.

Compressor Maintenance Expenses

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

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

However, the Benchmarking Report notes that GasNet has a very low compressor utilisation factor, reflecting its seasonal demand patterns. Intermittent stop-start operation leads to higher costs compared to other companies. The Benchmarking Report also notes that some of the companies in the study operate long haul systems with very high unit horsepower and high utilisation rates. This tends to put GasNet at a competitive disadvantage when its costs are compared to the all company group. Figure 9-3 in Schedule 9 compares GasNet's compressor maintenance expenses per million cubic metre-kilometre with those of the other companies in the sample.

8.5 K-factor carry over

GasNet's current Access Arrangement contains a Fixed Principle which provides that, in making a price determination in relation to a tariffed transmission service for the subsequent Access Arrangement period, the Commission must:

> *"have regard to the need to take into account the value of KT_t (as defined in part A of schedule 5) for the first year of the subsequent Access Arrangement period, as though that year represented a regulatory year "t" for the purpose of applying the formula for KT_t".*

GasNet has maintained an account representing the K factor and submitted this to the Commission each year as part of its annual tariff approval process. The K factor which is to be rolled forward into 2003 under the price control model will not be known until the end of 2002. Therefore, GasNet has made a forecast of the expected amount to be carried forward into the next regulatory period. Any discrepancy between the actual and forecast K factor for 2002 will be added to the K factor calculated for the year 2003 under the proposed new price control model for the Second Access Arrangement Period (see Schedule 3 of the draft Access Arrangement). The estimated K-factor to be carried forward is $14.0 million. GasNet proposes to add the forecast K factor carry forward to the forecast operating costs as an extraordinary expense applying at 1 January 2003. However, this cost will be levelised over the recovery period 2003 to 2007 in the same manner that operating costs are levelised with the selected X factor.

8.6 Benefit sharing allowance - efficiency gains in First Access Arrangement Period

8.6.1 *Background*

GasNet proposes to include in its revenue requirement an allowance reflecting efficiency gains made in the First Access Arrangement Period.

GasNet operates under a system of incentive based regulation whereby tariffs are locked-in during the Access Arrangement Period. The intention of incentive based regulation is to give the company an incentive to improve efficiencies and reduce costs over the term of the Access Arrangement so that customers can benefit from these efficiencies in subsequent years.

However, it is generally recognised that the incentive to improve efficiency is limited to the extent that a company can only keep the benefits of efficiency gains during the current Access Arrangement Period, after which they are passed on to Users. A company will clearly seek greater efficiency savings if it can keep these gains beyond the current Access Arrangement Period. The intention of "benefit sharing" is to promote a higher level of improvement in efficiency by sharing these benefits in subsequent Access Arrangement Periods between the company and the Users.

The Fixed Principle contained in GasNet's current Access Arrangement requires the Commission to ensure a fair sharing of efficiency gains between GasNet and Users in subsequent Access Arrangement Periods and, in ensuring a fair sharing of benefits, the Commission may have regard to (without limitation):

(a) the need to offer GasNet a continuous incentive to improve efficiencies both in operational matters and in capital investment; and

(b) the desirability of rewarding GasNet for efficiency gains, especially where those gains arise from the management initiatives to increase efficiency.

The fixed principle identifies operating costs and capital expenditure as two potential areas where efficiencies may be achieved.

8.6.2 *GasNet's proposal*

In relation to capital expenditure, GasNet considers that there is a limited role for benefit sharing. Unlike gas distribution businesses, GasNet's capital expenditure profile tends to be lumpy and well defined. Capital expenditure is usually confined to a small number of projects. Each of the capital expenditure projects is assessed on an individual basis and is subject to a prudent investment test (both *ex ante* and *ex post*) under the Code.

In relation to efficiencies in operating costs, GasNet proposes that the following model be used to assess the benefit from efficiencies in the current Access Arrangement Period to be shared between GasNet and Users in subsequent periods:

(a) assess the benefit that Users gain from the enduring efficiency improvements made during the First Access Arrangement Period;

(b) determine a reasonable share of these benefits that should be kept by GasNet and the quantum of that benefit; and

(c) build this benefit into the tariffs to apply over the Second Access Arrangement Period.

The benefit that Users gain from operating efficiencies made during the First Access Arrangement Period is calculated as the difference between the forecast of operating costs for the Second Access Arrangement Period (in real dollars) and the last year of the original forecast of operating costs ($2002).

Table 8-6: Calculation of Efficiency Gains

Original Tariff Model Operating Costs adjusted for additional workload[(a)]	$18.9 million
Less average Operating Cost Forecast 2003-2007[(b)]	-$16.6 million
Annual Benefit to Customer	$2.22 million

(a) The original tariff model forecast operating cost for 2002 was $17.2 million (in 2003) adjusted for actual inflation, after deducting an amount of $0.8 million for regulatory expenses which were budgeted for but not levied. This figure has been further adjusted upwards by $1.6 million per year to take into account the additional workload associated with new pipelines (the SWP and Interconnect) and further investment in compressors (Springhurst and Iona).

(b) This figure excludes reset costs, increase in insurance costs and the ESSO litigation costs.

Extrapolating these efficiency gains over the life of the GNS, the NPV of efficiency gains made during the First Access Arrangement Period is $27.0 million. GasNet proposes that a reasonable sharing of this benefit is 20%, or $5.4 million in 2003 (NPV). GasNet proposes to recover this share over the

Second Access Arrangement Period. This amount is included in the Non-Capital cost in 2003, and is levelised over the period 2003 to 2007 using the tariff X-factors.

8.6.3 *ESC approach not appropriate to GasNet*

An alternative mechanism for quantifying the carry-over of the reward associated with efficiency-improving initiatives has been proposed by the ORG (now the Essential Services Commission) in relation to access arrangements for gas distributors in Victoria.[77] Under this proposal GasNet would keep the financial benefit of an efficiency gain made at any time during an Access Arrangement Period for a term of five years. This would allow some (but not all) benefits to be retained beyond the current period and into the subsequent period.

Given a number of assumptions, these incentive arrangements would provide GasNet with approximately 30 per cent of the long term benefit generated by any efficiency gains, with the remainder flowing through to customers.

GasNet submits that the ESC model discussed above should not apply to efficiency gains made during the First Access Arrangement Period.

GasNet acknowledges that this model has the theoretical advantage of providing a consistent incentive to improve in each year of an access arrangement. However, the continuous incentive to improve only arises from this model if the model was known to GasNet at the commencement of the First Access Arrangement Period. GasNet was not aware that this incentive model would be applied, and therefore could not respond to it.

8.7 Asymmetric risks

8.7.1 *Proposal*

GasNet proposes to include in its cost of service an allowance reflecting the following asymmetric risks that are not adequately reflected elsewhere in the Total Revenue calculation. Table 8-7 below details each category of asymmetric risk.

Table 8-7: Categories of Asymmetric risk

Asymmetric Risk	Allowance ($ p.a.)
Property related risks	20,000
Deductibles in current insurance arrangements	140,000
Credit risk	252,000
Terrorist threat	65,000
Risk of stranding	75,000
Other risks	200,000
Total	**752,000**

GasNet accepts that specific risks should not be reflected in the rate of return calculated using CAPM. However, GasNet submits that, there are a number

[77] See Office of the Regulator General, *2003 Review of Gas Access Arrangements, Position Paper*, September 2001, Part III.

of specific risks that should be reflected in the Reference Tariffs. The key characteristics of these "allowable" risks are that:

(a) they are asymmetric (ie the possible negative outcomes are significantly larger than the possible positive outcomes);

(b) they are difficult (if not impossible) to insure against at commercial rates;

(c) they cannot be diversified away by investors because the counterparties to these risks are not public companies in which investors can invest; and

(d) taken together, they produce the result that the likely economic income that GasNet expects relating to the Reference Tariffs is less than the target economic income that is used to determine the Reference Tariffs (ie the Total Revenue).

These asymmetric risks are discussed further in Schedule 4.

8.8 Capital raising costs

Raising capital is an integral part of any commercial organisation and the costs associated with raising both debt and equity represent a significant and necessary expense.

GasNet proposes to include in its non-capital costs an annual allowance of $2.4 million in relation to its prudent capital raising costs, comprising the following amounts:

Table 8-8: Capital Raising Costs

Capital Raising Event	Annual allowance($ million)
Equity raisings (IPO, new placements)	0.5
Debt financing	2.0
Total	2.5

These costs are based on a combination of a reasonably prudent capital and debt raising program and GasNet's actual circumstances consistent with:

(a) funding ongoing capital expenditure; and

(b) market practice.

The debt raising cost consists of the fees and charges associated with the transaction of debt facilities. It is additional to the debt premium discussed under the WACC. Assuming an enterprise value of $539.7 million (GasNet's opening Capital Base), a gearing ratio of 60% and an average debt rollover period of 5 years, the debt raising allowance represents a transaction cost (in addition to the margin) of approximately 62 basis points. This is consistent with GasNet's recent debt financing costs.

This is also consistent with observable market data. A study which is often cited estimated the average total direct issuance costs as a percentage of the total proceeds for US Corporations during the period 1990 to 1994 as follows[78]:

Proceeds ($ US million)	Total Costs
$100 - 200	2.31%
$200 - 500	2.19%
>$500	1.64%

The equity raising allowance is a proxy for the transaction costs involved in raising equity capital, which could involve sale of the business, or smaller equity raisings to undertake capital expenditure. Based on a 40% equity component of the total enterprise value of $539.7 million, the proposed equity raising allowance corresponds to approximately 21 basis points. This is consistent with the costs of GasNet's recent IPO float amortised over 30 years.

[78] I. Lee, S. Lochhead, J. Ritter and Q. Zhao, "The Costs of Raising Capital" Journal of Financial Research, Spring 1996, pp 59-74.

9 Tariffs and Tariff Path

9.1 Summary of GasNet's Proposals

This section is designed to demonstrate the basis upon which tariffs for the Tariffed Transmission Service have been determined. Under the cost of Service methodology adopted by GasNet, Reference Tariffs are determined according to the following procedure.

(a) The target revenue is calculated for each year of the Second Access Arrangement Period based on forecasts of costs comprising a pre-tax return on capital invested, capital expenditure, depreciation, operating and maintenance expenses and other non-capital expenses, (see section 9.2 of this Submission).

(b) The peak and annual flows at each off-take are forecast for the Access Arrangement Period (see section 9.3 and Schedule 6 of this Submission).

(c) Costs are allocated to delivery points using the procedures described in section 9.4 and Schedule 5 of this Submission and the forecast tariffs determined by dividing the selected charging parameters into the allocated costs.

(d) Tariffs are grouped into injection pipelines and withdrawal zones, and smoothed to follow a CPI-X tariff path.

(e) Initial tariffs are determined for the year 2003, and a price control formula is specified to describe how the tariffs are to be adjusted each year (see section 9.5 of this Submission).

9.2 Forecast Revenue

9.2.1 *Code requirements*

Section 8.4 of the Code sets out three different methodologies for determining Total Revenue, namely Cost of Service, Internal Rate of Return (**IRR**) and NPV.

GasNet has proposed the Cost of Service model. Under this model, the Total Revenue recovers the following costs:

(a) pre-tax return on assets;

(b) depreciation; and

(c) operating, maintenance and other non-capital costs.

9.2.2 *GasNet's proposal*

GasNet's proposals in relation to each of these individual components that make up the revenue requirement have been detailed in other parts of this Submission.[79] Table 9-1 summarises each of these components.

Table 9-1: Summary of Components of the revenue requirement

Components of Revenue Requirement	2003	2004	2005	2006	2007
Return on assets	45.73	45.62	45.72	46.02	46.17
Depreciation	19.28	20.04	21.16	21.91	22.16
Non-capital costs	42.91	23.69	23.43	25.25	25.66
Total	107.92	89.35	90.31	93.18	93.99

To create a smooth pricing path, GasNet has proposed that tariffs in each year after the first year of the Access Arrangement Period should be escalated by the factor CPI-X. Consequently, forecast revenue calculated on the basis of tariffs multiplied by volumes will differ from the target revenue determined under the Cost of Service Methodology. The initial tariffs and the X value are set so that the NPV of the forecast revenue stream is the same as the NPV of the target revenue. The target revenues and forecast revenues for the five year regulatory period are set out in Table 9-2 below.

Table 9-2: Target and Forecast Revenue ($million)

Year ending 31 December	2003	2004	2005	2006	2007
Revenue requirement ($m)	107.92	89.35	90.31	93.18	93.99
Forecast Revenue ($m)	93.92	94.96	96.11	96.53	96.67

9.3 Forecast Volumes

9.3.1 *Code requirements*

Under section 8.4 of the Code, Total Revenue may be calculated on the basis of forecast volumes. In addition, sections 8.38 to 8.41 of the Code allow Reference Tariffs to be based on forecast volumes.

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

9.3.2 *GasNet's Proposals*

Section 4 of the AA Information contains summary information in relation to GasNet's volume forecasts. This section of the Submission is intended to provide an explanation of the assumptions underlying those forecasts.

The forecast annual volumes for the Second Access Arrangement Period and the forecast peak day volumes are set out in Table 9-3 and Table 9-4 below. The basis for the forecast is the annual volume forecast provided in the VENCorp Annual Planning Review. However, as discussed in section 9.6.3

[79] See section 6 (Rate of return), section 7.4 (Depreciation) and section 8 (Non-capital costs) of this Submission.

of this Submission, GasNet has modified the published VENCorp forecast to take into account a warming trend.

Table 9-3: Forecast Annual Withdrawal Volume 2003-2007

Annual Volumes (PJ/year)	2003	2004	2005	2006	2007
Conventional Market	204.0	211.0	217.7	221.3	223.7
Gas-Fired Power Station	12.2	14.3	15.0	15.9	17.6
Storage refill	3.6	3.6	4.3	3.2	3.4
Total	219.8	228.9	237.0	240.4	244.7

Table 9-4: Forecast Peak Day Volumes 2003-2007

Co-incident peak day (1:2) (TJ/day)	2003	2004	2005	2006	2007
Conventional Market	1075	1107	1139	1161	1175
Gas-Fired Power Station	57	67	70	74	82
Total	1132	1174	1209	1235	1257

The forecast injection volumes are set out in Table 9-5. These volumes refer to the average of the 10 peak days, which is the billing determinant used to levy the injection charges.

Table 9-5: Forecast Peak Day Injection[80] (Average of 10 peak injections)

TJ/day	2003	2004	2005	2006	2007
Longford	830	845	845	845	845
Culcairn	17	17	17	17	17
Port Campbell	182	207	234	248	256

9.3.3 *Forecast annual volumes*

The forecast volumes are based on the annual volume forecasts provided in the VENCorp APR. GasNet understands that this forecast is based on input from the National Institute for Economic and Industry Research, data from gas distributors and VENCorp's own internal research.

However, based on recent research, it appears that previous forecasts from VENCorp and its predecessors were biased upwards. The bias arose from a failure to identify a warming trend in Melbourne, which is apparent from the information charted by VENCorp in Figure 7.1 in Schedule 7 showing a history of annual degree days[81] for Melbourne. At the time of the First Access Arrangement, the total Effective Degree Days ("**EDD**")[82] for Melbourne for an average year was estimated to be 1532 EDD. Based on the trend analysis, VENCorp has determined that the best estimate for average weather in 2001 is 1445 EDD. Given a temperature sensitivity of 38

[80] Injection forecasts are limited by capacity constraints where relevant. There is no injection charge for LNG injections at Dandenong.

[81] The total Degree Days is the sum over each day of the year of Max (0, 18-T), where T is the average daily temperature in degrees Celsius.

[82] EDD is a mixed measure of temperature, wind chill factor, hours of sunshine and a seasonal factor which shows a greater correlation to gas demand than Degree Days alone.

TJ/EDD[83], the effect of this change is to reduce the forecast annual volume by approximately 3.3 PJ.

In preparing their forecast for the VENCorp APR, VENCorp chose not to extrapolate the warming trend evident in the data on the Melbourne DD (See Annexure 12 to this Submission). That is, VENCorp maintained a constant level of 1445 EDD for the forecast period. GasNet understands that this was because of uncertainty as to the cause of, and likely continuation of, this warming trend.

GasNet has commissioned a report from the CSIRO (which has been provided to the Commission) which sought to ascertain the cause of the trend, and to make an informed assessment as to the likelihood that the trend would continue. The report concluded that there has been a warming trend in Melbourne, and that it arises from a combination of the enhanced Greenhouse effect, and an urban heat island effect. The report also concluded that it was reasonable to expect this trend to continue.

On the basis of this report, GasNet has modified the published VENCorp forecast to continue the identified warming trend of 5.5 EDD/year. The effect of this modification is to reduce the forecast annual load in 2007 by approximately 1.2 PJ.

9.3.4 *Forecast peak day volumes*

The peak day forecast is taken from the VENCorp APR. VENCorp has not identified any evidence of a trend in peak day flows, despite evidence of a decline in annual volumes. However, the coldest day EDD is more variable year to year than the annual EDD and therefore it is more difficult to identify whether a trend is present. As it is likely that such a trend is likely to be very small, GasNet currently accepts the forecasts provided by VENCorp without modification.

There is very little information available on the peak day load within the gas-fired power stations. The situation is complicated by the fact that the relevant peak is the coincident peak day with the conventional market (ie industrial, commercial and residential market) and not the actual peak day consumption by the peaker power stations. Analysis of actual data for 2000 and 2001 shows that the coincident peak day for the gas-fired power stations is significantly lower than the actual peak day for this market segment. From an analysis of actual market data for 2000 and 2001, GasNet has estimated a coincident (winter) load factor of 59% for the gas-fired power load.

9.3.5 *Forecast gas exports*

Gas can be exported interstate from the GasNet system at the injection points at Iona (through the proposed Victoria-Adelaide pipeline), at Culcairn (into the EAPL pipeline), and possibly at Longford (into the EGP). The original TPA Access Arrangement included an assumption of 3 PJ/yr exported from Culcairn.

[83] Annual Gas Planning Review, VENCorp Energy Networks Corporation, November 2001, p 80.

GasNet considers that there will be significant net inflows of gas at each injection point. This means that any exports will be purely contractual, and will be back-hauling against the predominant flow. While this has occurred in the past to a limited extent, contractual counter flows are inefficient. By engaging in a simple gas swap, both forward and back-hauling parties can save significantly on their transmission charges.

GasNet is aware that at least one party intends to establish a trading hub in the near future. It is reasonable to suppose that by 2003, the practice of gas trading will be well established, and inefficient contractual counter-flows will be avoided. In light of these likely developments, and in the absence of any evidence for gas exports, GasNet has decided to forecast no interstate exports from the GasNet system.

9.3.6 *Withdrawal Tariff Zone forecasts*

GasNet has applied the global annual and peak day forecasts to the actual volumes at each off-take to generate a forecast of volumes withdrawn at each off-take, and by aggregation at each Withdrawal Tariff Zone. The forecasts have been further segregated into Tariff-D and Tariff-V loads. These forecasts have been moderated by the more detailed forecasts provided by VENCorp at the System Withdrawal Zone[84] level, for both annual and peak volumes.

Where additional information is available, specific off-take or zonal forecasts are made (while retaining the overall consistency with the annual and peak day forecasts). Specific forecasts have been made for the following off-takes and zones:

(a) Geelong (loss of cement production);

(b) Latrobe (growth of cogeneration load);

(c) Murray Valley (more rapid growth than the average); and

(d) Carisbrook (more rapid growth than average within the Wimmera[85] pipeline service area).

The supply to the gas-fired power stations occurs at specific existing off-takes on the GasNet system. Where necessary, GasNet has added new off-takes to supply a proposed peaker power station. As discussed above, GasNet has used a variety of information to assess the level of consumption at each off-take. The majority of the power generation load is located in the Metro zone, with smaller volumes taken in the Latrobe and SWP Zones.

Gas storage refills are located at the LNG facility at Dandenong and WUGS at Iona. The forecast of refill volumes depends on a range of commercial and market factors. It is also disproportionately affected by the severity of each winter. GasNet has constructed a simulation model of withdrawals and

[84] The System Withdrawal Zones divide the total system into six zones. These zones are used by VENCorp for system planning purposes.

[85] The Wimmera pipeline is owned by Coastal and is not part of the GasNet system, but it receives its gas supply from the GasNet off-take at Carisbrook).

injections into storage, which forecasts the expected refill volumes assuming average weather conditions.

GasNet has made a forecast of expected refill volumes based on:

(a) the simulation model;

(b) the contractual take-or-pay arrangements at the WUGS facility; and

(c) the MSO Rules for the operation of the LNG facility.

However it is important to note that these forecasts are highly uncertain. GasNet has adopted a tariffing method which charges only the marginal operating cost for refill volumes. Therefore any increase or decrease in refill volumes will be reflected in approximately equal changes in fuel costs.

9.3.7 *Supply Forecast*

Historically, most of the Victoria's gas has been supplied by Esso/BHP Billiton from Bass Strait. However, with the completion of the Interconnect Pipeline, the SWP and the EGP, the Victorian market now has access to the gas resources in the Cooper Basin, the Otway Basin and the Kipper, Baleen and Patricia fields in Bass Strait. Given the diversity of supply sources available to the Victorian market, it is clear that there will be an increasing level of competition to supply the market.

Table 9-6 sets out the potential sources of gas.

Table 9-6: Potential sources of Gas

Injection Zone	Gas Supply
Longford	• Bass Strait fields controlled by Esso/BHPP; • Baleen/Patricia/Kipper fields, connected to the EGP at Orbost and supplied at Longford via the VicHub;
Port Campbell	• Port Campbell onshore fields developed by Santos; • Off-shore Otway fields at Thylacine and Geographe being developed by Origin and Woodside; • WUGS storage facility; • Offshore Otway fields at Minerva and La Bella being developed by BHP/Billiton;
Pakenham	• possible development of Yolla
Culcairn	• Moomba fields
Dandenong	• LNG storage facility

In this highly competitive market, it is extremely difficult to project the likely level of supply of gas from each source. There is no independent and reliable source that can provide this information. In addition, much of the information that is available in the market is confidential. In the light of these circumstances, GasNet has relied on the following information to determine the supply forecasts:

(a) contractual gas supply information as published by VENCorp in the Annual Planning Review;

(b) supply plans and contracts announced in the press;

(c) confidential discussions with industry participants; and

(d) reasonable assumptions as to the outcome of the competitive process.

GasNet's assumptions as to the likely level of supply from each of these sources is set out in Schedule 6.

9.4 Cost allocation and tariff setting

9.4.1 *Tariff design principles*

GasNet has not made significant modifications to the current tariff design. This is because:

(a) the unique circumstances of the Victorian Market Carriage system constrain the ability to vary the tariff design principles significantly; and

(b) there are benefits in maintaining consistency in tariffs between periods. This minimises costs and complexities for Users in assessing risks and upgrading systems.

However GasNet has addressed some anomalies in the original cost allocation procedures and some areas where the tariff can be considerably simplified without detriment to existing Users. In addition, GasNet has been approached by a number of market participants who have identified areas where a bypass pipeline would be more economical than the existing transmission tariff, which suggests that some aspects of the existing tariff design are not efficient.

The tariff design for the Second Access Arrangement Period is structured along the following principles, which are unchanged from the existing design except where noted. The justification for these design principles was canvassed in detail in (and accepted by the Commission as part of) the original TPA Access Arrangement Information.

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

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

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

(d) Costs are allocated to 1 in 2 winter peak flows and annual flows in the ratio or 60% to peak and 40% to annual. This differs from the current model which allocates 65% of costs to the 1 in 20 winter peak flow. (The cost allocation procedure is described in detail in Schedule 5.7.)

(e) Withdrawals are charged within 15 withdrawal zones or points (an increase over the current 12 zones or points to reflect the need for prudent discounts).

(f) Within each withdrawal zone there are up to 3 tariff classes. The existing tariff classes of Tariff-D and Tariff-V are supplemented by a storage refill tariff. The reason for introducing two new classes is discussed in Schedule 5.10.

(g) Injection tariffs are charged at each of the injection zones, except Dandenong.

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

(i) The withdrawal charge is levied on the actual flows each month (an "Anytime" charge). A different withdrawal charge applies to each tariff class. The reason for changing from the existing design is discussed in Schedule 5.10.

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

9.4.2 *Cost allocation procedures*

A detailed description of the cost allocation procedures is set out in Schedule 5.7. In summary, costs are grouped into the following categories and allocated as shown in the following table Table 9-7.

Table 9-7: Cost Allocation Procedures

Cost Category	Allocation Method
System Assets (return on and of capital) (excluding the SWP and Interconnect Assets)	Physical path
Direct Operating Costs[86]	Physical path
Costs rolled-in under the System-Wide Benefits Test (Interconnect Assets)	Postage Stamp
SWP Costs	Direct to zone
Interconnect Zone Residual Costs	Direct to zone
Non-System Assets[87] (return on and of capital)	Postage Stamp
General & Administrative Operating Costs	Postage Stamp
Return on Working Capital	Postage Stamp
Benefit Sharing Allowance and K-Factor Carry-Over	Postage Stamp
Asymmetric risk	Postage Stamp

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

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

Cost Category	Allocation Method
System Assets (return on and of capital) (excluding the SWP and Interconnect Assets)	Physical path
Capital raising costs	Postage Stamp

A separate incremental cost allocation regime applies to the SWP and the Interconnect. GasNet is proposing an injection tariff to recover the entire cost of the SWP and 8% of the Interconnect Pipeline. The relevant costs that must be recovered from the injection tariff are the asset costs (return on and of capital) and the incremental costs associated with the projects. This is a direct allocation procedure as indicated above.

9.5 Tariff path

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

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

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

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

The fixing of the price path constitutes an incentive mechanism. The tariff adjustment procedure is not altered if actual volumes or actual costs differ from the initial forecast, except as provided for in the pass-through procedures discussed in section 9.9 of this Submission. This methodology exposes GasNet to both volume and cost risk, and removes these risks from GasNet customers.

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

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

GasNet has operated under a similar price control mechanism during the First Access Arrangement Period. However, as a result of individual tariff component rebalancing constraints, and given significant under-recoveries of revenue in each year, GasNet has accumulated a large correction factor which has not been recovered during the First Access Arrangement Period. GasNet proposes to remove these constraints in the Second Access Arrangement Period so that GasNet revenues are always brought back to the prescribed average revenue after no more than one year.

With respect to the individual tariff components, the standard procedure is to escalate each component annual by the CPI-X factor, where there is a specific X for each tariff component. However, it is possible that this procedure will not lead to the correct average revenue, as described above (that is, the published average revenue, as adjusted for actual inflation and for any over/under recoveries from the previous year). This will require an adjustment to the tariff components. GasNet proposes that, in the first instance, the tariff components for any year will be adjusted by an equal percentage increase-(decrease) above the tariff components derived by applying the standard CPI-X formula to the previous year's tariff components. The adjustment will be made to ensure that the average revenue expected for that year will be equal to the published average revenue, adjusted for actual inflation, and for any over/under recoveries in the previous year. Because all tariff components are adjusted by the same percentage, the tariff relativities between customers will be maintained. However, GasNet also believes that it is appropriate to retain some flexibility to rebalance the relative weights of one tariff component against another, where for example GasNet believes that gas volumes are being inhibited by the tariff design. Given the overall average revenue target, GasNet will only benefit from this procedure where it believes that the volume growth (and hence welfare gain) expected from a reduction in one tariff component is greater than the volume decline expected from the increases in other tariff components.

Hence GasNet proposes that any tariff component can be adjusted by up to 2% above the equal percentage change discussed above. This will require a decrease in other tariff components relative to the equal percentage change.

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

9.6 New Facilities Investment

Under GasNet's proposed Access Arrangement any extension to, or expansion of, the GNS will be covered by the Access Arrangement unless GasNet gives notice to the ACCC stating that the extension will not form part of the Access Arrangement. This is consistent with the policy contained in GasNet's current Access Arrangement except that the restriction on excluding only "significant" extensions (ie extensions costing more than $5 million or extensions greater than 10 kilometres) has been removed.

GasNet submits that the requirement to automatically include small laterals as part of the Covered Pipeline inhibits investment in those pipelines, particularly where the laterals are funded by one or more foundation customers. If a lateral pipeline is covered, it automatically comes under the MSO Rules and therefore there is no guarantee that the foundation customers will be allocated transmission rights above other Users. With the benefit of experience, GasNet submits that the requirement to include small extensions as part of the Covered Pipeline is unduly restrictive.

In addition, extending coverage to small laterals is implicitly allowing for open access to these laterals. This is incompatible with the nature of those pipelines which are essentially service lines to a specific customer. GasNet is at a severe disadvantage in tendering to build these laterals as alternate pipeline companies can offer a dedicated pipeline to the prospective User.

All revisions to the Access Arrangement to increase the Capital Base to recognise the costs incurred in constructing an extension or expansion will be considered under the relevant provisions of the Code (including sections 8.15 to 8.19).

9.7 Capital Redundancy

The redundant capital policy in GasNet's current Access Arrangements provides that the Commission may review, and if necessary, adjust the Capital Base to take account of "wholly or partially redundant assets".

The reference to "partial redundancy" in GasNet's current Access Arrangement creates some uncertainty in that it is not clear what level of redundancy is required before an asset will be removed from the Capital Base. For example, if a pipeline is not fully utilised in a particular year could this result in the pipeline being excluded from the Capital Base.

The GNS is an integrated system and therefore, it is important that only those assets which no longer contribute to the provision of the service in any way are excluded from the Capital Base. For this reason, GasNet proposes to adopt a revised capital Redundancy Policy which provides that the Capital Base may only be adjusted to take account of wholly redundant assets, being assets which no longer contribute in any way to the provision of the Tariffed Transmission Service.

9.8 Incentive Mechanism

9.8.1 *Code requirement*

Section 8.44 of the Code provides that a Reference Tariff Policy should, wherever the relevant regulator considers appropriate, contain a mechanism to enable a Service Provider to recover all or a share of any returns from the sale of a Reference Service that exceeds the level expected at the beginning of the Access Arrangement Period. The mechanism should be designed to encourage the service provider to:

(a) increase the volume of sales of all Services;

(b) minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services;

(c) develop new services in response to the needs of the market for Services;

(d) undertake only prudent investment; and

(e) ensure that Users and Prospective Users gain from any increased efficiency, innovation and improved sales (but not necessarily in the Access Arrangement period during which such increased efficiency, innovation or volume of sales occur).

9.8.2 *Aspects of efficiency carryover*

There are two aspects of the efficiency carryover.

(a) The treatment of the carryover of efficiency gains made in the first regulatory period (ie 1998 to 2002) in the 2003 to 2008 regulatory period.[88]

(b) The efficiency carryover mechanism to be applied in the long term (ie 2008 onwards).

9.8.3 *Post - 2002 incentive mechanism*

GasNet has included a Fixed Principle in the Access Arrangement relating to how efficiency gains achieved in the Second Access Arrangement Period are to be treated in the subsequent Access Arrangement Period. The Fixed Principle provides that:

> The Commission must include in the Reference Tariffs for the Third Access Arrangement Period an allowance relating to the efficiency gains achieved in the Second Access Arrangement Period, calculated as follows:
>
> $B = S \times NPV$ in perpetuity of $(C_2 - C_3)$
>
> where
>
> B is the benefit sharing allowance, which cannot be less than zero;
>
> S is an amount (between 0 and 1) representing a reasonable share of these benefits that should be kept by GasNet taking into account the actual conditions faced by GasNet, including the ageing of the GNS and changes in workload;
>
> C_2 is the forecast operating costs approved by the Commission for the last year of the Second Access Arrangement Period adjusted to account for additional workload;
>
> C_3 is the average forecast operating costs approved by the Commission for the Third Access Arrangement Period;
>
> All amounts are expressed in 2008 dollars.

As discussed in section 8.6.3 of this Submission, an alternative method for quantifying the carry over of the reward associated with efficiency improving initiatives has been proposed by the ESC in relation to access arrangements for gas distributors in Victoria. For the reasons set out below, GasNet does

[88] This is discussed in section 8.6 of this Submission.

not consider that this is an appropriate incentive mechanism for future Access Arrangement Periods.

(a) The ESC model assumes that operating costs will continue to decrease over time. However, most operating costs (particularly maintenance costs) will increase over time with the aging of the system, rather than show a decrease due to efficiency improvements.

(b) The model links operating costs to the incentive mechanism rather than allowing an independent assessment of the prudency of the forecasts as required by the sections 8.36 and 8.37 of the Code.

(c) The model contemplates the negative carry over of costs which exceed the benchmark forecast. This adds additional risk to the company, as the company is already taking a risk by tying its revenue to a forecast of costs, where that cost forecast may not be achieved due to events out of the control of the company. For example, GasNet has experienced unexpected costs during the First Access Arrangement Period as a consequence of the Longford explosion and the extremely high insurance costs incurred post September 11.

9.8.4 *Volume risk incentive*

In addition, GasNet is subject to volume risk. Therefore, it has a strong incentive to promote gas consumption in Victoria.

9.9 Pass through events

9.9.1 *GasNet's proposal*

GasNet proposes to include in the GasNet Access Arrangement a set of pass through rules which would permit GasNet to apply to the Commission to pass through within-period cost changes relating to:

(a) a change in taxes event;

(b) a regulatory event; and

(c) an insurance event.

The key features of GasNet's proposal is that these events are all beyond GasNet's control and any pass through is subject to approval by the Commission.

GasNet submits it is reasonable, given the five-year duration of the Second Access Arrangement Period, to accommodate a streamlined process for the pass through of these costs.

9.9.2 *Change in Taxes Event*

This would entitle GasNet to pass through the costs associated with changes in taxes (other than income tax and capital gains tax). For example, if land taxes increased, then GasNet would be able to pass through the associated costs.

9.9.3 *Regulatory Event*

This would entitle GasNet to pass through the costs associated with regulatory changes that materially increased the costs associated with the GNS. For example, if the gas safety regulatory regime was changed to increase significantly GasNet's safety costs, then this would be a pass through event.

9.9.4 *Insurance Event*

Following recent international events, there has been a hardening of the insurance market, which has resulted in a significant increase in premiums. In these circumstances, GasNet considers the most efficient solution to be that:

(a) GasNet's Transmission Tariffs will incorporate the cost of insurance premiums at current rates; but

(b) if there is a material increase in insurance costs, then GasNet is entitled to pass through the increased costs.

Therefore, this pass through event would apply if there has been a change in one or more costs in the insurance comprising GasNet's specified minimum insurance level and, as a result of that change, the aggregate costs of GasNet's insurance exceeds the benchmark insurance costs incorporated into the Transmission Tariffs.

9.10 Reference tariffs and reference tariff policy

9.10.1 *Code requirements*

Section 3.4 of the Code requires the Regulator to be satisfied that the Access Arrangement and any Reference Tariff to be included in the Access Arrangement comply with the Reference Tariff Principles described in section 8 of the Code.

Section 3.5 of the Code requires the Access Arrangement to include a policy describing the principles that are to be used to determine a Reference Tariff. The Reference Tariff Policy must, in the Regulator's opinion, comply with the Reference Tariff objectives set out in section 8 of the Code.

9.10.2 *GasNet's Proposal*

Clause 4 of GasNet's Access Arrangement sets out GasNet's proposed Reference Tariffs and Reference Tariff Policy. Schedule 5 of this Submission also contains a detailed explanation of the constituents of the proposed Reference Tariffs.

GasNet submits that its proposed Reference Tariffs and Reference Tariff Policy are consistent with the objectives set out in section 8 of the Code. In clause 9.10.3 below, GasNet describes how each of those objective have been met.

9.10.3 *Section 8.1 objectives*

Recovery of efficient costs associated with the provision of Reference Service - 8.1(a)

GasNet proposes to retain the Cost of Service Methodology for revenue determination, which is the methodology used in the current PTS and WTS Access Arrangement. Under this approach, the Reference Tariffs approved by the Commission must deliver a revenue stream sufficient to recover the efficient costs of providing the Reference Service. The “efficient costs” referred to in section 8.1(a) refer to both non-capital costs and capital expenditure.

GasNet has submitted key performance indicators and a summary of a benchmarking study undertaken by Cap Gemini which suggest that GasNet’s costs compare favourably with other pipelines companies. This is discussed in further detail in section 8.4 of this Submission.

The major items of forecast capital expenditure include the Brooklyn Loop, Gooding compressor station refurbishment and the Lurgi pipeline refurbishment. As discussed in section 7.3 of this Submission, GasNet considers that each of these items of capital expenditure is likely to pass the requirements of section 8.16 of the Code when the expenditure is expected to occur.

On this basis, GasNet submits that its proposed Reference Tariffs are set at the appropriate level to recover the efficient costs of providing the Reference Service.

Replicating the outcome of a competitive market - 8.1(b)

GasNet’s regulated rate of return is based on CAPM benchmarks. Therefore, the returns achieved are expected to be similar to those achieved by firms facing similar market risks. Pricing that is reflective of efficient costs is also a feature of competitive markets.

As indicated above, GasNet considers that its proposed Reference Tariffs are set at an appropriate level to recover the efficient costs of providing the Reference Service. In addition, GasNet submits that its proposals in relation to the WACC and associated parameters are commensurate with the conditions prevailing in markets for funds and the risk involved in delivering the Reference Service[89].

On this basis, GasNet submits that its proposed Reference Tariffs are consistent with the objective of replicating the outcome of a competitive market.

Ensuring the safe and reliable operation of the pipeline - section 8.1(c)

GasNet’s proposed Reference Tariffs are based on costs forecast as being necessary for the safe and reliable operation its pipelines. As discussed in section 8 of this Submission, GasNet submits that the proposed Reference

[89] Refer to section 6 of this Submission.

Tariffs and Reference Tariff Policy are consistent with the safe and reliable operation of the pipeline.

Not distorting investment decisions in pipeline systems nor in upstream or downstream industries - section 8.1(d)

The rate of return set by the Regulator should be sufficient to cover the Service Provider's cost of capital. A rate of return that is lower than that required by the Service Provider to cover the cost of capital will not attract investment in the long run. A higher level than required rate of return could enable a Service Provider to set tariffs at a level which would allow them to earn monopoly rents and result in the misallocation of resources.

GasNet considers that its proposed rate of return at a level which is consistent with the principle of not distorting investment decisions.

Efficiency in the level and structure of the reference tariffs - section 8.1(e)

GasNet's proposed Reference Tariffs are discussed in Schedule 5 of this Submission. These tariffs are all set between the marginal cost and deprival value of the particular service and GasNet submits that they meet the requirements of the Code.

Incentives to reduce costs and to expand the market - 8.1(f)

GasNet's proposals meet this requirement. For example:

(a) GasNet tariffs are not altered by changes in costs (except as provided for in the Pass-Through rules). This means that GasNet keeps the gains from efficiency improvements till the end of the regulatory period, and therefore has an incentive to pursue efficiencies. Moreover, GasNet's proposed benefit sharing regime for operating efficiencies (see section 9.8 of this Submission) provides GasNet with an increased incentive to achieve lower costs; and

(b) the volume risk implicit in the price control methodology (see section 9.5 of this Submission) provides GasNet with an incentive to maximise gas volumes.

9.10.4 *Section 8.2 objectives*

Total Revenue to be established consistently with the principles and according to one of the methodologies contained in section 8 of the Code - section 8.2(a).

GasNet's revenue requirements are based on the cost of service methodology which is consistent with the Code. GasNet considers that its proposals in relation to the value of the Capital Base to be rolled forward, Depreciation and operating and maintenance costs are consistent with the principles contained in section 8 of the Code.[90]

[90] See sections 6, 7.4 and 8 of this Submission.

The proportion of total revenue that any one reference tariff is designed to recover is calculated consistently with the principles of section 8 of the Code - section 8.2(b).

GasNet's cost allocation procedures are described in Schedule 5 of this Submission. The costs associated with GasNet's unregulated activities (metering and LNG) have been separated from the costs associated with the regulated service according to a set of transparent accounting measures. Details of the allocation of costs between regulated and unregulated activities have been provided to the Commission on a confidential basis. GasNet submits that these procedures are consistent with the principles of section 8 of the Code.

The proportion of total revenue recovered from users of a service is calculated consistently with the principles of section 8 of the Code - section 8.2(c).

Section 8.42 of the Code provides that pricing should, to the maximum extent that it is technically and commercially reasonable, be cost reflective.

As discussed in Schedule 4, GasNet considers that its tariff methodology is consistent with the principles contained in section 8.42 of the Code.

Incentive mechanisms are incorporated consistently with the principles of section 8 of the Code - section 8.2(d)

GasNet's proposed Access Arrangement incorporates an incentive mechanism that permits GasNet to retain certain returns (if any) from the Transmission Tariffs during the Second Access Arrangement Period. GasNet submits that this mechanism is consistent with the principles set out in section 8 of the Code.

Forecasts are best estimates - section 8.2(e)

As discussed in section 9.6, GasNet submits that its forecast volumes are reasonable.

10 Access policies, terms and conditions and review of arrangement

10.1 Summary of GasNet's proposals

10.1.1 *Allocation of responsibilities*

Consistent with section 10.2 of the Code, there has been an allocation of responsibilities between GasNet and VENCorp relating to the different elements of an Access Arrangement. Each of GasNet and VENCorp is responsible for the description of a Services Policy and Reference Tariffs. However, VENCorp is responsible for describing the terms and conditions of access, the Capacity Management Policy, the Trading Policy and the Queuing Policy. GasNet is responsible for the Extensions/Expansions Policy.

10.1.2 *Services Policy*

As set out in the draft GasNet Access Arrangement, GasNet proposes to revise the form of its Services Policy to bring it into line with underlying commercial and regulatory arrangements. These revisions will have no substantive impact on Users shipping gas via the GNS.

The key elements of GasNet's proposal are as follows.

(a) As the GNS is a Market Carriage transmission system, Users and Prospective Users of the GNS are offered one Reference Service (or bundle of Reference Services), being the transportation of gas via the MSO Rules.

(b) VENCorp, as operator of the GNS under the MSO Rules, is responsible for the provision of the Reference Service.

(c) Although it is a "Service Provider" under the Code, GasNet does not, under the MSO Rules, provide gas transmission services directly to Users.

(d) For the purposes of Reference Tariff calculation, the Reference Service comprises two components:

  (i) the VENCorp Services, which VENCorp provides itself (these are dealt with in the VENCorp Access Arrangement); and

  (ii) the Transmission Service, being the benefit of the availability of the GNS. In order to provide this component, VENCorp relies on the Service Envelope Agreement with GasNet.

GasNet has discussed this proposal with VENCorp, which has indicated it has reservations about the proposal.

10.2 Allocation of Access Arrangement responsibilities

10.2.1 *Background*

Under the Code, both the owner and operator (if any) of a Covered Pipeline must lodge an Access Arrangement (as a result of the wide definition of "Service Provider").

However, the Code recognises the commercial reality that a number of gas pipelines involve a legal and commercial separation between a pipeline owner and a pipeline operator and that, in certain circumstances, the owner/operator model may make it difficult for each party to comply fully with the Code.

Section 10.2 of the Code provides that where (as in the case of the GNS) there is a separate owner and operator of a pipeline, the owner and operator may, by the cumulative effect of their Access Arrangements (which, of course must be approved by the regulator) allocate responsibility for complying with the obligations imposed under the Code.

This allocation is relatively straightforward in relation to the operational obligations under the Code (for example, the requirement under section 5.1 of the Code to establish an information package for users). However, these provisions are also capable of applying in relation to the allocation of Access Arrangement requirements. For example it would be sufficient for the role of operating a queuing policy to be allocated to the operator only. This is consistent with the approach approved by the Commission in the 1998 Access Arrangements.

10.2.2 *Proposed allocation of responsibilities*

Consistent with this approach, GasNet proposes that responsibilities be allocated between GasNet and VENCorp under section 3 of the Code relating to the elements of an Access Arrangement as shown in Table 10-1.

Table 10-1: Allocation of Access Arrangement responsibilities

Element	Contained in VENCorp Access Arrangement?	Contained in GasNet Access Arrangement?
Services Policy	Yes (see section 10.2 below)	Yes (see section 10.2 below)
Reference Tariffs	Yes - relating to VENCorp Services	Yes - relating to Transmission Services (see section 10.2 below)
Terms and Conditions	Yes - as per MSO Rules	No
Capacity Management Policy	Yes - market carriage	Yes - market carriage
Trading Policy	Yes - as per MSO Rules	No
Queuing Policy	Yes - as per MSO Rules	No
Extensions and Expansions Policy	No	Yes
Review and expiry dates	Yes - 1 January 2008	Yes - 1 January 2008

GasNet submits that this allocation is consistent with the Code and, subject to the treatment of the Reference Service (see section 10.2 below) is consistent with the current GasNet and VENCorp Access Arrangements.

10.3 Services Policy

10.3.1 *Background*

As set out in the draft GasNet Access Arrangement, GasNet proposes to revise the form of its Services Policy to bring it into line with underlying commercial and regulatory arrangements. The key change is to clarify that VENCorp is not a "User" within the meaning of the Code. These revisions will have no substantive impact on Users shipping gas via the GNS.

The current Access Arrangements were among the first Access Arrangements to be proposed under the national gas access regime and the only Access Arrangements to grapple with a Service Envelope Agreement and a Market Carriage regime. With the benefit of experience since 1998 in the interpretation and practical implementation of these Access Arrangements GasNet considers that the current Services Policy does not accurately reflect the underlying commercial and regulatory arrangements and is potentially confusing for Users as to the nature of the relevant legal relationships.

In order to understand the background to this issue, it is necessary to examine the legal relationships established as part of the restructuring of the Victorian gas transmission system in 1998.

As discussed in section 3.2 of this Submission, GasNet owns the GNS and VENCorp operates the GNS. GasNet and VENCorp are parties to the Service Envelope Agreement, under which:

(a) GasNet agrees to:

  (i) make available the entire GNS to VENCorp; and

  (ii) provide a range of supporting services to VENCorp; and

(b) VENCorp agrees to:

  (i) operate the GNS in accordance with the MSO Rules; and

  (ii) have the direct legal relationship with Users regarding a range of issues, including payment of charges for transmission services.

VENCorp effects the transmission of gas for Users via the market carriage system, which comprises:

(a) the MSO Rules (which both VENCorp and the Users must comply with). The MSO Rules, in conjunction with the Tariff Order, set out the basis on which VENCorp may recover its costs through the VENCorp tariffs; and

(b) a Gas Transportation Deed between VENCorp and each User, under which the User promises to pay the transmission charges directly to GasNet (although GasNet is not a party to this Deed).

The MSO Rules, in effect, establish a comprehensive regime governing access to and the operation of the PTS. For example:

(a) section 52 of the *Gas Industry Act 2001* (Vic) provides that the purpose of the MSO Rules is the regulation of the operation of the gas transmission system for the purposes of achieving a competitive market for gas in which third parties are granted access to the "gas transmission system" (ie the PTS); and

(b) under the MSO Rules, a retailer which uses the PTS must register with VENCorp (clause 1.1.5) and all registered participants who intend to inject gas into or withdraw gas from the PTS must do so via nominations lodged with VENCorp under the MSO Rules (clause 3.1.2).

As a result, any market participant who seeks access to ship gas on the PTS is compelled by the regulatory regime to deal with VENCorp under the MSO Rules. Although GasNet has some operational interface with market participants (for example, in relation to metering or allocation of "new" AMDQ) it has no direct legal relationship with market participants in relation to the shipping of gas on the PTS.

10.3.2 *Defects in the current Services Policy*

The Services Policy in the current PTS Access Arrangement provides that:

(a) the Reference Service provided by GasNet comprises making the "tariffed transmission service" available to VENCorp "as User";

(b) the "tariffed transmission service" is defined as making the PTS available to VENCorp, for VENCorp to operate in accordance with the MSO Rules.

GasNet does not dispute that it provides services to VENCorp in the form of the Service Envelope Agreement. However, GasNet considers that the characterisation of the Reference Service and the description of VENCorp as "User" in the current Access Arrangement are inconsistent with the Code.

Purpose of Code

The purpose of the Code is to promote third party access to pipeline services. However, the services under the Service Envelope Agreement are, by definition, services that can only be provided to one person (in this case VENCorp).

Consistent with this philosophy, the Code adopts a different definition of "services" from that used in Part IIIA of the *Trade Practices Act 1974* (which governs access to essential facilities). In particular, under the *Trade Practices Act*, the definition of a "service" expressly includes *the use of an infrastructure facility*. However, the definition of "Service" under the Code (which follows a similar format) omits this item. This is consistent with GasNet's view that the Code governs access to services provided *by means of* pipelines as opposed to the *use of* a pipeline.

Service sought by significant part of market

Under the Code, at least one Reference Service must be likely to be sought by a significant part of the market. In the circumstances, it is difficult to see how the system availability under the Service Envelope Agreement (as opposed to the haulage of gas by means of that availability) is sought by any person other than VENCorp or how VENCorp can be said to constitute a significant part of the market.

Similarly, if the GasNet Reference Service constitutes making the transmission system available to VENCorp, then is that a Service which other Users can seek and which, under the Code, GasNet could be compelled to provide?

Service Envelope Agreement

Under the Code, the main purpose of a "Reference Service" is to enable a User who does not have a contract for that service to enjoy a "short circuit" route to seek access to the Reference Service at the applicable Reference Tariffs (ie by means of the arbitration process in the Code). However, VENCorp already has its entitlement to the system availability under the Service Envelope Agreement and therefore does not require the current specification of the Reference Service.

Not surprisingly, the current Access Arrangement (which provides that GasNet will make the tariffed transmission service available to VENCorp as User) is inconsistent with clause 11.2 of the Service Envelope Agreement[91], which provides that GasNet must prepare and send to each market participant periodic invoices *for the tariffed transmission services provided by VENCorp to that market participant*.

10.3.3 *GasNet's proposal*

The key elements of GasNet's proposal are as follows.

(a) The overall structure, as seen by shippers, will not change. The only substantive change is the description of the relationship between GasNet and VENCorp.

(b) As the GNS is a market carriage transmission system, Users and Prospective Users of the GNS are offered one Reference Service (or bundle of Reference Services), being the transportation of gas via the MSO Rules.

(c) VENCorp, as operator of the GNS under the MSO Rules, is responsible for the provision of the Reference Service.

(d) Although it is a "Service Provider" under the Code, GasNet does not, under the MSO Rules, provide gas transmission services directly to Users.

(e) For the purposes of Reference Tariff calculation, the Reference Service comprises two components:

[91] A copy of which was published as part of the approval of the ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998).

(i) the VENCorp Services, which VENCorp provides itself (these are dealt with in the VENCorp Access Arrangement); and

(ii) the Tariffed Transmission Service, being the benefit of the availability of the GNS. In order to provide this component, VENCorp relies on the Service Envelope Agreement with GasNet.

As discussed above, GasNet's proposal simply reflects the existing underlying commercial and regulatory arrangements. These commercial and regulatory arrangements were recognised by the Commission where, in section 1.2 of the Final Decision, the Commission observed that:

> *Although [GasNet] as the pipeline owner and VENCorp as the pipeline operator are both service providers as defined under the Victorian Access Code, [GasNet will not] directly provide services to users or prospective users … VENCorp will then provide services to other users of the PTS in accordance with the MSOR … From a practical perspective, VENCorp may be considered to be the real service provider.*

10.3.4 *What this Access Arrangement covers*

As a result of this proposal, and consistent with section 10.2 of the Code, the draft GasNet Access Arrangement proceeds on the basis that:

(a) responsibility for the VENCorp Services component of the Reference Service Policy is allocated to VENCorp; and

(b) responsibility for describing the Tariffed Transmission Service component of the Reference Service is allocated to GasNet.

Therefore, this Access Arrangement relates to the Tariffed Transmission Service, including the portion of the Reference Tariff applicable to the Tariffed Transmission Service.

10.3.5 *Transmission Service*

As discussed above, the Tariffed Transmission Service is a component of the Reference Service and comprises the benefit of the availability of the GNS. VENCorp obtains this availability under the Service Envelope Agreement and the Tariffed Transmission Service (as part of the bundle of services provided to Users) is provided on the terms and conditions set out in the MSO Rules.

There is no further material or "fuller" description of the Tariffed Transmission Service. This illustrates a key advantage of the GasNet proposal, namely that by reflecting the MSO Rules and the Service Envelope Agreement (which contain all the relevant detailed provisions), the Services Policy can be kept brief and simple.

10.4 Terms and conditions of service

The terms and conditions on which Users obtain the Reference Service are set out in the MSO Rules.

Consistent with section 10.2 of the Code, responsibility for complying with the obligation to include terms and conditions of supply in an Access Arrangement have been allocated to VENCorp.

10.5 Capacity management policy

GasNet proposes that the GNS be a Market Carriage Pipeline. Under section 3.8 of the Code, the Regulator must not accept an Access Arrangement which states that the Covered Pipeline is a Market Carriage Pipeline, unless each relevant Minister in the jurisdictions in which the Covered Pipeline is located have given their consent to the classification of the pipeline as a Market Carriage Pipeline. As discussed in section 3.4 of this Submission, the New South Wales and Victorian Ministers have notified GasNet of their consent to the classification of the GNS as a Market Carriage pipeline.

10.6 Trading policy

Under section 3.9 of the Code an Access Arrangement for a Covered Pipeline which is described in an Access Arrangement as a Contract Carriage Pipeline must include a Trading Policy. However, as GasNet has proposed that the GNS be a Market Carriage Pipeline, section 3.9 of the Code does not apply.

10.7 Queuing policy

Consistent with section 10.2 of the Code, responsibility for the requirement to include a Queuing Policy in an Access Arrangement has been allocated to VENCorp.

10.8 Extensions and expansions policy

Section 3.16 of the Code provides that an Access Arrangement must include a policy which:

(a) sets out the method to be applied to determine whether any extension or expansion to the pipeline should be treated as part of the Covered Pipeline; and

(b) specifies how an extension or expansion which is to be treated as part of the Covered Pipeline will effect tariff.

The first of these requirements is dealt with in clause 5.1 of the Access Arrangement, which provides that any extension to, or expansion of, the GNS will be covered by the Access Arrangement unless GasNet gives a notice to the ACCC stating that the extension will not form part of the Access Arrangement. This is consistent with the policy contained in GasNet's current Access Arrangement except that the restriction on excluding only "significant" extensions (ie extensions costing more than $5 million or extensions greater than 10 kilometres) has been removed. This is discussed further in section 9.6 of this Submission.

In relation to the second requirement, clause 5.2 of the Access Arrangement deals with the effect of an extension or expansion on Reference Tariffs. Clause 5.2 provides that all revisions to the Access Arrangement to increase the Capital Base to recognise the costs incurred in constructing an extension or expansion will be considered under the relevant provisions of the Code (including sections 8.15 to 8.19).

10.9 Review and expiry of Access Arrangement

The adoption of a five year Access Arrangement Period is consistent general with practice. In addition, the Revisions Commencement Date coincides with the expiration of the Service Envelope Agreement. A five year Access Arrangement Period is also consistent with the fixed principles in the Tariff Order where the definition of "subsequent access arrangement period" is defined as the period of 5 calendar years from 1 January 2003.

GasNet and VENCorp have agreed that the Revision Commencement Date will be 1 January 2008.

10.10 Fixed Principles

In accordance with section 8.47 of the Code, GasNet proposes to include two Fixed Principles in its Access Arrangement, one dealing with the K factor carry over and the other dealing with the sharing of efficiency gains.

GasNet proposes that if, at the end of the Second Access Arrangement Period, there is an accrued balance in the K-Factor of the Price Control Formula in Schedule 4 of the Access Arrangement, then that accrued balance would be carried forward into the Reference Tariffs for the Third Access Arrangement Period. This simply allows for a true up (in either direction) consistent with the proposed Price Control Formula.

In relation to the issue of the sharing of efficiency gains, GasNet proposes that the following model be used to assess the benefit to be shared from the Second Access Arrangement Period to the subsequent Access Arrangement Period:

(a) assess the benefit that customers gain from efficiency improvements made during the Second Access Arrangement Period, which is measured as the difference between the forecast operating costs for the new regulatory period and the last year of the forecasts for the Second Access Arrangement Period;

(b) determine a reasonable share of these benefits that should be kept by GasNet during the subsequent Access Arrangement Period and the quantum of that benefit; and

(c) build that benefit into the tariffs to apply over the subsequent Access Arrangement Period.

GasNet submits that this approach to the sharing of efficiency gains is consistent with the objectives set out in section 8.44 of the Code and provides the Commission with an appropriate degree of flexibility in applying the Fixed Principle to the subsequent Access Arrangement Period.

11 Interpretation

11.1 Glossary

Access Arrangement has the meaning given in the Code.

Access Arrangement Period has the meaning given in the Code.

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

AMDQ means Authorised MDQ under the MSO Rules.

Anticipated Incremental Revenue has the meaning given in the Code.

APT means Australian Pipeline Trust.

Capacity Management Policy has the meaning given in the Code.

Capital Base has the meaning given in the Code.

CAPM means the Capital Asset Pricing Model.

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

Commission means the Australian Competition and Consumer Commission.

Cost of Service Methodology means the revenue methodology of that name described in clause 8.4 of the Code.

Covered Pipeline has the meaning given in the Code.

Depreciation Schedule has the meaning given in the Code.

EPD means the Energy Projects Division of the Victorian Department of Treasury and Finance.

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

ESC means the Essential Services Commission.

Extensions/Expansions Policy has the meaning given in the Code.

Final Approval means the final approval of the TPA and VENCorp Access Arrangements issued by the Commission on 16 December 1998.

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

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

Fixed Principles has the meaning given in the Code.

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

GasNet (NSW) means GasNet Australia (NSW) Pty Ltd ABN 14 079 136 413 (formerly Transmission Pipelines Australia (Assets) Pty Ltd).

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

GFCV means Gas and Fuel Corporation, Victoria.

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

GNS means GasNet System.

GTC means Gas Transmission Corporation.

Incentive Mechanisms has the meaning given in the Code.

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

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

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

KPI means key performance indicator.

Market Carriage has the meaning given in the Code.

Market Carriage Pipeline has the meaning given in the Code.

Market Participant has the meaning given in the MSO Rules.

MSO Rules has the same meaning given in the *Gas Industry Act 2001* (Vic).

New Facilities Investment has the meaning given in the Code.

Non Capital Costs has the meaning given in the Code.

Operating Lease Arrangement means the short-term arrangement for lease of the PTS and WTS between TPA and TPAA.

ODRC means optimised depreciated replacement cost.

Pipeline has the meaning given in the Code.

Prospective Users has the meaning given in the Code.

PTS means the principal transmission system and has the meaning given in the PTS Access Arrangement.

PTS Access Arrangement means the Access Arrangement by GasNet for the PTS which was first approved by the Commission for the period 15 March 1999 to 31 December 2002.

PTS Capital Base means the Capital Base of the PTS from time to time.

Queuing Policy has the meaning given in the Code.

Rate of Return has the meaning given in the Code.

Recoverable Policy has the meaning given in section 8.18 of the Code.

Reference Service means the service described in clause 3.2 of the Access Arrangement.

Reference Tariff has the meaning given in the Code.

Reference Tariff Policy has the meaning given in the Code.

Revisions Commencement Date has the meaning given in the Code.

Revisions Submission Date has the meaning given in the Code.

Second Access Arrangement Period means the Access Arrangement Period commencing on 1 January 2003 and ending on 31 December 2007.

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

Services has the meaning given in the Code.

Services Policy has the meaning given in the Code.

Service Provider has the meaning given in the Code.

Speculative Investment has the meaning given in the Code.

Speculative Investment Fund has the meaning given in the Code.

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

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

Tariffed Transmission Service means the availability of the GNS, as sourced by VENCorp through the Service Envelope Agreement.

Tariff Order means the Victorian Gas Industry Tariff Order 1998.

Total Revenue has the meaning given in the Code.

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

TPAA means GasNet (NSW) (formerly Transmission Pipelines Australia (Assets) Pty Ltd).

Trading Policy has the meaning given in the Code.

Transmission Tariff means the provision of the Reference Tariff for the Reference Service associated with the Tariffed Transmission Service, calculated in accordance with the Access Arrangement.

Users has the meaning given in the Code.

VENCorp means Victorian Energy Networks Corporation.

VENCorp Access Arrangement means the Access Arrangement by VENCorp for the PTS which was approved by the Commission for the period 15 March 1999 to 31 December 2002.

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

Victorian Code means the Victorian Third Party Access Code for Natural Gas Pipeline Systems made on 9 December 1998.

WACC means weighted average cost of capital.

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

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

WUGS means the Western Underground Gas Storage located at Iona.

11.2 Referencing conventions

This Submission includes abbreviated references to a number of regulatory decisions following the conventions described in Schedule 8.

12 List of Schedules

13 List of Annexures

This Submission is accompanied by a range of supporting material comprising the following annexures:

Annexure 1: Extracts from relevant materials

Annexure 2: NECG - Market Risk Premium (**Confidential**)

Annexure 3: NECG - Regulatory Treatment of Accelerated Tax Depreciation (**Confidential**)

Annexure 4: NECG - Imputation Credits (**Confidential**)

Annexure 5: NECG - Asset, Equity and Debt Beta (**Confidential**)

Annexure 6: Remaining Economic Life of GasNet's Transmission Assets, prepared by Saturn Resources (**Confidential**)

Annexure 7: Valuation of Non-Insured Risks prepared by Trowbridge (**Confidential**)

Annexure 8: CSIRO Report - Projected changes in temperature and heating degree-days for Melbourne, 2003-2007

Annexure 9: 2001 Comparative Performance Benchmarking for Natural Gas Pipeline Industry prepared by Cap Gemini (**Confidential**)

Annexure 10: Consultation Paper on Proposed Tariff Design for the Victorian Gas Transmission System, prepared by NERA

Annexure 11: VENCorp Energy Networks Corporation, Annual Planning Review 2002-2006, dated November 2001

Annexure 12: Melbourne DD Trend prepared by VENCorp