Response to the Commission's draft decision

on proposed access arrangement for the Principal Transmission System

Dated 20 December 2007

Contents

1 Introduction

1.1 Background

On 30 April 2007, GasNet Australia lodged with the Commission its proposed Access Arrangement and Access Arrangement Information for the Victorian PTS for the period 2008-2012, together with a detailed submission in support of the proposed Access Arrangement. GasNet is the owner of the PTS and VENCorp is the operator of the PTS.

On 14 November 2007, the Commission released its Draft Decision on GasNet's proposed Access Arrangement. The Commission has invited written submissions on the Draft Decision.

This is GasNet's response to the Commission's Draft Decision. GasNet may make further submissions and to respond to submissions lodged by other interested parties.

This response adopts the conventions established in GasNet's Submission, in particular, the glossary in section 14.1.

1.2 Confidentiality

This response is not confidential.

2 Roll forward of Capital base

2.1 Corrections for 2002 forecasts (DD section 3.1.5.1)

Draft Decision

In calculating its Capital Base at the beginning of the AA2 period, GasNet provided an estimate of $0.66 million for capex in 2002, whereas the actual capital expenditure in this period was $0.31. The Draft Decision proposes to claw back the returns earned by GasNet on the overestimate. The Draft Decision calculates that the return on the value of this overestimate over the AA2 period is $6.91 million.

The Draft Decision also proposed that the Capital Base be adjusted to take into account the difference between the forecast inflation for the December quarter of 2002 (0.54%) and the actual inflation for the December quarter of 2002 (0.72%) and that a return on the resultant increase in the Capital Base be allowed. The Draft Decision calculated the amount of the extra return as $0.34 million.

GasNet Response

Inflation adjustment

GasNet agrees with the Draft Decision's estimate of the extra return to account for the inflation adjustment.

Capital expenditure adjustment

The capital expenditure forecast for 2002 incorporated in GasNet's Second Access Arrangement was $0.574 million not $0.66 million as stated in GasNet's Submission (see GasNet AA Information dated 17 January 2003, Table 2-1, Regulatory Asset Base.xls). Accordingly, the difference between the forecast and actual capital expenditure for 2002 is actually $0.267 million.

GasNet notes that the amount of the return on the value of the overestimate calculated by the Draft Decision is incorrect. The return on this amount over AA2 is actually $0.108 million rather than $6.91 million as proposed by the Draft Decision. The calculation of this amount includes allowance for CPI indexing of the amount and compounding of the return annually. It does not make allowance for depreciation of the capital amount as no adjustments are made for actual depreciation rather than forecast. That is, the depreciation associated with this capital amount has been deducted from GasNet's opening Capital Base for AA3 so GasNet does not gain any extra benefit from the depreciation on this amount.

As demonstrated above, the amount of the over-recovery is an immaterial amount in the context of GasNet's overall revenue proposal. As such, GasNet is surprised at the proposal to regulate forecast revenue to this level.

2.2 Brooklyn to Lara Pipeline (DD section 3.1.5.3)

Draft Decision

The Brooklyn to Lara pipeline project (previously known as the Corio Loop) was approved by the Commission in June 2006 in response to an *ex ante* application made by GasNet under section 8.21 of the Code. At that time the Commission determined that an amount of $63.7 million ($2006) was reasonably expected to pass the prudent investment and system wide benefits test under the Code.

As part of its Submission, GasNet proposed that this amount be treated as forecast capital expenditure on an as-commissioned basis. However, the Draft Decision requires GasNet to capitalise actual (or a best estimate of) capital expenditure incurred on the Brooklyn to Lara pipeline to 31 December 2007, including interest during construction, and to include the remainder of the costs as forecast capital expenditure.

The Draft Decision also noted that the Commission had not had time to review the revised cost estimate for the project which had been submitted by GasNet and will do so as part of its final decision.

GasNet Response

With respect to the allocation of costs between the current and next regulatory period, GasNet is indifferent to the mechanism used to roll the asset into the Capital Base, provided the interest during construction is calculated consistently.

Construction of the Brooklyn to Lara pipeline has commenced. The steel pipe has been procured and coated, the easements have largely been acquired and an EPC contract has been tendered leading to the appointment of a construction contractor on a fixed price contract. Field work commenced in October this year.

On 21 August 2007, GasNet provided the Commission with detailed information on the current status of the Brooklyn to Lara Pipeline project, including the latest design and construction basis, route map, cost estimates and the monthly profile of costs. This information is shown in Attachment 1. The revised cost estimate at that time was $68.9 million (actual dollars).

On 18 October 2007, GasNet formally submitted a further revised cost of $69.0 million (actual dollars) to the Commission and requested that it consider the higher cost estimate for approval in the Draft Decision. This cost, in 2006 dollars, is $67.37 million, which is 5.7% higher than the amount approved by the Commission in 2006 as part of the *ex ante* decision. The Code requires that the Commission must be satisfied that this higher amount also passes the tests in section 8.16(a) of the Code in order to approve the revised cost.

The dominant reason for the increase in costs for the project relates to the increase in construction costs which has occurred over the past two years. In early 2007, GasNet conducted a tender in order to select a preferred construction contractor for the project. Three bidders were short listed and asked to submit detailed bids in relation to the project. After assessing all of the tenders, GasNet determined that the most efficient tenderer was A J Lucas and on that basis it was awarded the contract. Given the competitive nature of the tender conducted by GasNet, GasNet considers that the overall revised costs for the project do not exceed the amount that would be invested by a prudent Service Provider.

GasNet also submits that the higher revised cost for the project continues to pass the test in section 8.16(a)(ii)(B) of the Code. This is because the small cost increase of $3.7 million in 2006 dollars, which is less than a 6% increase, is insignificant compared to the net market benefits (benefits in excess of costs) of $93.1 million ($120 million if competition benefits are included) identified by VENCorp for this project.

On this basis GasNet submits the revised cost of $69.0 million (plus return on investment costs during construction) for approval for the Brooklyn to Lara pipeline as part of the current Access Arrangement revision.

3 New Facilities Investment

3.1 Corporate Restructuring Costs (DD section 3.2.5.2(ix))

Draft Decision

The Draft Decision rejected GasNet's proposal that $8.84 million in corporate restructuring costs be recovered through incorporation into the Capital Base. The Draft Decision's view was these costs are not costs associated with delivering the reference service and that these costs would be taken into account by each party in arriving at the price for buying and selling the asset.

GasNet Response

GasNet's response to this issue is dealt with in sections 9.3-9.4.

4 Forecast Augmentation Capital Expenditure

4.1 Overview (DD section 3.3)

GasNet's proposed capital expenditure program included an amount of $245.90 million in respect of augmentation capital expenditure. The Draft Decision rejected all of this capital expenditure except for the pre-approved Brooklyn to Lara pipeline project.

Capital expenditure in relation to the Sunbury, Ballarat and Carisbrook loops, the Stonehaven compressor and the Brooklyn Wollert easements was rejected on the basis that it did not satisfy the prudent investment test under section 8.16(a)(i) of the Code.

Capital expenditure in relation to the Northern Zone, and Pakenham and Warragul loops was rejected on the basis that the requirements of the system integrity test were not reasonably expected to be satisfied. In the case of the Northern Zone augmentation and the Warragul loop, the Draft Decision's view was that the economic feasibility test and not the system integrity test is the more appropriate test to apply to these projects.

4.2 Use of system integrity test for augmentations (DD section 3.3.4.2)

Draft Decision

The Draft Decision accepted GasNet's interpretation of "integrity" and that *prima facie*, capex proposals for the purpose of avoiding breaches of the minimum system pressure requirements could meet the system integrity test. However, the Draft Decision does not accept that the underlying driver for augmentation capital expenditure is an anticipated breach of the minimum system pressure requirements. It believes that the proposals are expansive in nature and driven by the need to meet increasing demand and therefore should be assessed under the economic feasibility test.

GasNet Response

GasNet submits that the Draft Decision's interpretation and application of the system integrity test is incorrect and not appropriate in the circumstances.

The Draft Decision took the view that it is necessary to ensure that the correct test under section 8.16(a)(ii) of the Code is applied because of the cost recovery implications. The Draft Decision states that:

- the economic feasibility test ensures that capital costs incurred are principally recovered from incremental users who benefit from the capex proposal;
- the system integrity test generally results in recovery from users localised to the segment of the network where system integrity is maintained; and

- the system-wide benefits test provides for recovery from users across the entire network.

There is nothing in the Code to justify this interpretation. Section 8.16(a)(ii) includes three alternative tests - if proposed capex meets one of those tests the amount of the investment can be rolled into the Capital Base. While the tests may, as the Draft Decision suggests, have different cost recovery implications in some circumstances, it is possible, and indeed for many proposals likely, that proposed capital expenditure will meet more than one of the tests in section 8.16(a)(ii). Where this is the case, the regulator does not have the discretion to decide that a capex proposal which meets one of the tests under section 8.16(a)(ii) will not be allowed unless it is also demonstrated to meet another one of the tests.

GasNet submits that:

(a) approval of the augmentation capex under the system integrity test is consistent with the Code because the augmentations proposed are necessary to maintain minimum system pressure (in the context of increasing demand and the market carriage system);

(b) this interpretation is supported by decisions of other regulators in relation to distribution networks; and

(c) application of the economic feasibility test in the context of the expansion to meet load growth in market carriage system is inappropriate because the capex costs cannot be allocated to incremental users or to incremental usage of existing users.

GasNet also believes that the proposed augmentation capital expenditure meets the system-wide benefits test. The PTS is a single integrated pipeline system and augmentations which allow GasNet to continue to deliver gas across Victoria benefit all users.

Maintaining minimum system pressure in the context of market carriage

GasNet believes that augmentations are justified under the system integrity test notwithstanding that they would also enable the PTS to meet increasing demand. GasNet believes that this argument is even more compelling in the context of the market carriage system.

Market carriage incorporates a number of important features that are different from a traditional contract carriage transmission pipeline. In general terms, the objective of the market carriage system is to use market signals rather than firm contractual rights to allocate gas/capacity on the pipeline.[1] More particularly:

(a) shippers are not required to reserve specified capacity under long-term contracts in order to ship the gas through the market carriage system (instead, they can request various amounts of gas on any given day);

[1] See section 52(3) of the Gas Industry Act 2001 and clause 1.1.2 of the MSOR.

(b) subject to emergency 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 on gas supply and through which all gas imbalances are taken to be bought or sold.

A related component to providing safe and secure services to VENCorp is the requirement that access to such services be provided to all users. VENCorp's curtailment powers are limited to emergencies and threats to system security. The MSO Rules and the market carriage system are based on the premise that there will be sufficient capacity to meet demand at the market clearing price. In contract carriage transmission pipelines, where the Service Provider can enter into a contract to underpin the cost of capital required to provide capacity in excess of contracted MDQ. However, in the Victorian system there is no mechanism (commercial or regulatory) which requires users to make a commitment to contribute to the costs (before or after the investment is undertaken).

Therefore, as market carriage systems are designed to give access in order to meet load and demand requirements, the capital expenditure must be implemented in order for the market carriage system to work as intended and in accordance with the market objective (with minimum pressure levels maintained). Accordingly, the augmentation is necessary to maintain the integrity of the services in the context of the market carriage system.

Regulatory precedent

The interpretation and application of section 8.16 of the Code by State regulators supports GasNet's position that its augmentation proposals meet the system integrity test. Generally, State regulators have approved capital expenditure under the system integrity test (or indicated that it would be permitted under the Code to do so) in much broader circumstances, as set out below.

- The ESC of South Australia acknowledged the need for security of supply augmentations on the basis of reducing the risk of outages, notwithstanding that the augmentations may have other outcomes and benefits, such as increasing capacity and accessibility for certain areas.[2]

- In its recent draft decision on the gas distribution networks regulatory reset, the ESC in Victoria appears to have taken the view that it is not obliged to expressly consider whether the appropriate test in section 8.16(a)(ii) has been met. Instead, it relied on section 8.49 of the Code to determine whether a Reference Tariff meets the requirements of Chapter 8 of the Code. In particular, the ESC appears to have

[2] Essential Services Commission of South Australia, Draft Decision, Proposed Revision to the Access Arrangement for the South Australian Gas Distribution System, March 2006 p 121-122, and Final Decisions, 30 June 2006, pg 113. Although ESCOSA rejected the inclusion of the proposed augmentations in the forecast new facilities investment, this was not based on a concern with the merits of the projects but on doubts over the timing of the projects and cost anomalies.

inferred that the capex proposals meet one of the tests in section 8.16(a)(ii).

- In 2000 and 2005 IPART approved forecast capex under the system integrity test for the Alinta AGN Limited (formerly AGL Gas Networks) gas distribution network for an augmentation to the "primary loop". The augmentation was required to meet load growth.

Application of economic feasibility test

Unlike contract carriage pipelines, GasNet does not contract directly with users in relation to the reservation of capacity on its pipelines. As a result, it is not possible for GasNet to differentiate between different users of a particular section of pipeline and therefore charge different tariffs (or a surcharge) in relation to that use.

Further, in relation to most of the increased demand, it is not possible for GasNet to differentiate the incremental volume from the existing volumes within a given zone and therefore identify the incremental demand. This is in part because GasNet does not have a direct contractual relationship with users and in part because the increased demand largely relates to incremental demand (including residential demand) in established areas rather than substantial new developments. As a result, the only practical procedure is to charge a surcharge to all gas demand within each relevant zone.

As discussed above, the Draft Decision took the view that it is necessary to ensure that the correct test under section 8.16(a)(ii) of the Code is applied because of the cost recovery implications. However, in practice, if the incremental users cannot be identified this reasoning is not compelling or appropriate for the following reasons.

- All end-users using a particular segment of the network (ie all end-users in a zone) will be required to pay for the capex. As a result, the allocation of capex costs between the economic feasibility test and the system integrity test may not differ (the extent of any difference would largely depend on the cost allocation policy, which is discussed further below).

- The economic feasibility test is likely to result in tariff spikes in certain areas, particularly regional areas, which is likely to affect economic development in those areas. This is not appropriate given that there is no compelling justification for the cost allocation proposed by the Draft Decision.

In contrast, GasNet believes that the cost allocation method it has employed with the system integrity test is fair, reasonable and cost reflective (and permitted by the Code). Costs are allocated to users according to the use they make of GasNet's assets, but assets are valued at their optimized replacement cost, rather than at their depreciated value. This removes the effect that asset vintage has on allocated costs. This methodology, and the principles behind it, have been accepted in the past by the Commission for refurbishment capital expenditure, and GasNet believes it is equally valid and appropriate for augmentation capital expenditure. The key principle underlying this method is that users who receive the same service should not pay significantly different tariffs due the extent of depreciation of the individual assets serving each user. This is implicit in the allocation method under the system integrity test, but is inconsistent with the method of allocation under the economic feasibility test.

4.3 Northern Zone (DD section 3.3.4.3(i))

GasNet Proposal

GasNet proposed a major augmentation of the northern pipeline from Wollert to Culcairn by winter 2009, to address forecasted breaches of minimum pressures at Culcairn and Shepparton. The pressure breaches at Culcairn will prevent GasNet from honouring the allocation of 17 TJ/day of AMDQ for exports at Culcairn.

The project consists of three parts:

(a) $39.6 million to replace existing aging assets and expand the Wollert compressor station;

(b) $14.6 million to install a 12.1km loop from Wollert to line valve 3 on the northern pipeline; and

(c) $24.9 million to construct a new compressor station at Euroa.

The total cost for the combined project is $79.1 million.

Draft Decision

The Draft Decision considers that the amount of $79.1 million is reasonably likely to satisfy the prudent investment test. However, the Commission has taken the advice of Sleeman Consulting that a single loop to line valve 5 is preferred to the combination of a shorter loop to line valve 3 and a new compressor station at Euroa. This is because, having regard to the greater operating costs associated with the Euroa compressor, this proposal results in the lowest sustainable costs over time.

The Draft Decision considers that the part of the investment which maintains the export capability at 17 TJ/day meets the system integrity test, whereas the part of the investment which addresses the breach of minimum pressures on the Echuca lateral should be assessed against the economic feasibility test. The Commission requires that the portion of the asset which is assessed under each test should be apportioned on the basis of expected gas flows.

GasNet Response

Prudent investment test

GasNet has carefully reviewed the alternative proposal put forward by Sleeman Consulting. Sleeman Consulting's preference for the longer loop option is based on the following assumptions:

- the capital cost is marginally lower;

- the operating costs of a pipeline are lower than the operating costs of a compressor; and

- the fuel gas use is lower with a longer loop than with the Euroa compressor.

GasNet's view is that the true differences between the options are marginal for the reasons set out below.

- Sleeman Consulting's overall costing is not materially different from GasNet's estimate.

- The fuel gas use under the GasNet proposal is in fact lower than the fuel gas use under the longer loop scenario, despite the fact that GasNet is proposing a new compressor station.

  This has been confirmed by new analysis of the fuel gas forecast which has attempted to optimise the operation of the Wollert and Euroa compressors. Assuming that VENCorp does operate the system optimally, then it has been found that on up to 200 days a year, the Euroa compressor can take the compression burden off the Wollert compressor. The Saturn compressor proposed for Euroa is smaller and therefore uses significantly less fuel than the proposed Centaur unit at Wollert, and hence over the course of a year the combined system is marginally more fuel efficient than the Wollert compressor alone. GasNet has calculated an annual saving in fuel gas use of about 19 TJ.

- Sleeman Consulting is correct that there is an operating cost advantage to its proposal. GasNet estimates the annual operating cost (excluding fuel) at Euroa to be 2.2% of the capital value,[3] which is approximately $0.54 million/year. In comparison the operating cost of the longer loop is only $0.05 million/year. Therefore, the operating cost of the Euroa option is marginally higher than for the longer loop option, even allowing for the fuel saving.

However, GasNet believes that the Euroa option should be preferred because it gives greater flexibility to match future capital expenditure to the expansion of the system over time. Assuming the relatively low demand growth from the VENCorp 2007 APR, the future capital expenditure under the Euroa option is more closely matched to the growth of demand than under the longer loop scenario. The timing of these investments has been confirmed by VENCorp system planning. Based on GasNet's modelling, the net present value of costs under each scenario is shown in the table below. For the longer loop, GasNet has used its own capex estimate as well as Sleeman Consulting's lower capex estimate.

[3] GasNet has observed historical opex as 2.9% of compressor ORC. However Calvert has noted that with the escalation in facility costs, it is more appropriate to use 75% of this value.

Table 4.1: NPV of investment options

NPV (excl Wollert)	GasNet capex	Sleeman Consulting capex
Euroa option	$52.1 million	$50.5 million
Loop option	$55.0 million	$53.3 million
Difference	$2.9 million (5.6%)	$2.8 million (5.5)%

It can be seen from the table that the Euroa option has a 5.5% advantage over the loop option, even after allowing for the higher operating costs of the compressor. Therefore on the basis of a present value analysis, the lowest sustainable cost over time is reasonably likely to be obtained by constructing the Euroa compressor station and a short loop to line valve 3.

It should be noted that this augmentation scenario is based on a low 0.9% growth per annum from the latest long term VENCorp volume forecast. This forecast assumes slowing of demand due to a Greenhouse response, which may not apply in the northern zones. If growth was faster than assumed, then the benefit of the Euroa option would be even greater.

Other reasons that favour the Euroa compressor option are that it:

- will be configured to compress both north and south, so there is greater ability to import gas from Culcairn in a system emergency, enhancing security of supply;
- supports potentially greater growth on laterals, in particular the Echuca/Shepparton lateral, since the Euroa compressor can maintain maximum pressures into the inlet of the lateral; and
- improves operational flexibility by providing better control of linepack, which is required to manage fluctuations in withdrawals from the northern zone, and fluctuations in the inlet pressure to the Wollert compressor station.

In the event that the Commission does not accept GasNet's submissions, GasNet is concerned that:

- it will not receive an opex allowance for the Euroa compressor in AA3 or in future regulatory periods; and
- if it proceeds with the project as it has proposed, there is a risk that these assets will not be rolled into the Capital Base at the next regulatory review, even if the actual amount of the investment is equivalent to the Commission's preferred asset mix.

System integrity test

GasNet's general response to this issue is contained in section 4.2 above.

If this test is applied, it is likely that a significant Surcharge would be required on customers in the Echuca zone, which could lead to reduced consumption or lower growth in demand. GasNet would have to consider whether this imposed an unacceptable risk profile on the investment which is incompatible with the regulated rate of return. It may be that the expansion cannot be justified at the regulated rate of return.

However, if it were accepted that “expansive” augmentations should be considered under the economic feasibility test, GasNet believes that the Commission’s application of this principle to the Northern zone should be clarified.

Refurbishment capital expenditure

More than one third of the proposed investment relates to refurbishment of the Wollert compressor station. The Wollert compressor station would have required refurbishment even in the absence of a need to augment the northern zone because it is near the end of its economic life, as explained in the GasNet Compressor Strategy report submitted with its access arrangement revisions in April 2007. The three Saturn units at Wollert would have required replacement at an estimated cost of $27 million in order to maintain the capability of the station.

This amount of the investment should therefore be assessed under the system integrity test because they are required to maintain the continuity and reliability of existing services.

Apportionment of investment to the economic feasibility test

The Draft Decision has created two categories of investment for the purpose of the application of the 8.16 tests. Augmentation designed to maintain the AMDQ at Culcairn is deemed to pass the system integrity test, whereas augmentation designed to avoid a breach of minimum pressures on the Echuca lateral is required to pass the economic feasibility test.

The total investment to be apportioned between the system integrity test and the economic feasibility test is $79.1 million less the refurbishment component of $27 million, which leaves $52.1 million. The Commission requires that the apportionment of this amount be based on the gas flows. The gas flows relevant to the economic feasibility test are the forecast flows on the Echuca lateral, which is subject to a breach of minimum pressures from 2010. The flows relevant to the restoration of the 17 TJ/day of export capability are the flows in all remaining Northern zones. It is general growth in all these zones which has led to the threat to the export capability. The relevant gas flows are the flows in the Wodonga, North Hume, South Hume and Murray Valley zones, plus the 17 TJ/day of exports at Culcairn, plus a portion of the flows into the Calder zone along the Kyneton lateral to Bendigo.

Because the augmentation is driven by the peak day forecast, the relevant apportionment should be based on forecast peak day gas flows in each zone.

Application of the economic feasibility test

In the event that the economic feasibility test must be applied to this investment, then GasNet may seek approval for a Surcharge under section 8.25 of the Code. This would be based on the apportionment of costs discussed above. In particular:

(a) the forecast amount of $27 million would be included in the forecast Capital Base under the system integrity test as discussed above;

(b) of the remaining $52.1 million, the portion associated with restoration of the 17 TJ/day of export capability would also be included in the forecast Capital Base under the system integrity test; and

(c) of the remaining amount associated with the Echuca lateral, the Recoverable Portion would be included in the Capital Base. The Recoverable Portion would be the amount which is reasonably expected to pass section 8.16(a)(ii)(A) of the Code (noting that the Draft Decision has found that the whole investment passes the prudent investment test). The remaining forecast investment will be recovered by a Surcharge.

The Recoverable Portion would be calculated as the amount that would be recovered from the Anticipated Incremental Revenue, which is defined in the Code as:

> *"the present value (calculated at the Rate of Return) of the reasonably anticipated future revenue from the sale of Services which would not have been generated without the Incremental Capacity, minus the present value (calculated at the Rate of Return) of the best reasonable forecast of the increase in Non-Capital Costs directly attributable to the sale of those Services."*

The appropriate Prevailing Tariff would be the Echuca zone tariff derived using the standard GasNet tariff model, where the model would be applied to 2008 volume forecasts in the zone, and which excludes the amount of investment which would be the subject of the economic feasibility test. For periods beyond AA3, the Prevailing Tariff would be deemed to be the approved 2012 tariffs, escalated at the forecast CPI.

The relevant incremental volume to which the Prevailing Tariff would be applied is the forecast volume growth in the Echuca zone above the 2009 forecast. The Anticipated Incremental Revenue would be the net present value of the product of the Prevailing Tariff and the incremental volume over the economic lives of the relevant assets.

The incremental Non Capital Costs would be the incremental costs to operate the Euroa compressor and the 12 km loop, apportioned to the Echuca lateral in the same way as the capital expenditure. The costs to operate the Wollert compressor would be deemed to be included in the general opex forecast.

As noted above, if a Surcharge is required, it will be dealt with under a separate process. However, for current purposes GasNet notes that the Surcharge would be calculated at the approved WACC on the remaining investment not covered by the system integrity test or the Recoverable Portion. It would be derived under the standard methodology, using real straight line depreciation over the economic life of the relevant assets. The Surcharge would be applied at a postage stamp rate to the total volumes in the

Echuca zone. The Surcharge would be applied to the total volumes since it is impossible to distinguish the incremental users from the existing users in this zone.

The Surcharge would be reassessed at each reset based on the approved volume forecasts, economic lives and WACC.

4.4 Sunbury and Ballarat loops (DD section 3.3.4.3(ii) and (iii))

Draft Decision

The Draft Decision states that the augmentations of the Sunbury and Ballarat loops are not likely to pass the prudent investment test in section 8.16(a)(i) of the Code. This is on the basis of the Sleeman Consulting report that pressures at Sunbury and Ballarat will not be breached during the next regulatory period.

This is related to the fact that the Commission has accepted GasNet's proposal for the upgrade of the Brooklyn compressor station, which will involve the installation of two new Centaur units 13 and 14 to replace the existing Saturn units. The upgraded units can provide duty compression power of 3500 kW into the Ballarat to Ballan pipeline which exceeds the currently available compression power of 1700 kW.

GasNet Response

On the basis of the further modelling conducted by VENCorp in relation to Sunbury and Ballarat looping projects, GasNet accepts that with the use of upgraded compressors at Brooklyn, the pressures at Sunbury and Ballarat will not be breached during the next regulatory period.

Accordingly, as long as the installation of units 13 and 14 at Brooklyn is approved, GasNet accepts that these project should not at this stage be included in its forecast capital expenditure for AA3. However, if for any reason, the installation of units 13 and 14 at Brooklyn is not approved by the Commission, then the proposed Ballarat and Sunbury loops will be required in 2010 and 2012 respectively, and should be approved by the Commission.

4.5 Warragul loop (DD section 3.3.4.3(iv))

Draft Decision

The Draft Decision states that the augmentation of the Warragul lateral is appropriate, but has determined that an amount of $4.43 million is prudent, rather than $4.84 million as proposed by GasNet. This is on the basis of Sleeman Consulting's advice that GasNet's contingency estimate of 20% is excessive.

However, the Draft Decision requires that GasNet demonstrate that this project passes the economic feasibility test before it can be included in the Capital Base.

GasNet Response

Prudent investment test

GasNet believes that its cost estimate is reasonable and prudent. While Sleeman Consulting has independently derived a cost estimate that is 9% lower than GasNet's estimate, Sleeman Consulting was nevertheless of the opinion that the GasNet estimate is reasonable and consistent with good industry practice. In light of this opinion, the Commission should accept the GasNet proposal.

System integrity test

GasNet's general response on the appropriateness of the system integrity test for pipeline augmentations is set out in section 4.2.

However, in the event that the Commission does not approve this investment under the system integrity test and if GasNet decides to proceed under the economic feasibility test, it would seek approval for a Surcharge if required.GasNet would calculate the Recoverable Portion and the Surcharge using the same methodology as discussed above in section 4.3. In the case of the Warragul loop, the relevant zone would be the Lurgi zone, and the relevant volume would be the forecast demand within the Lurgi zone. The Surcharge would apply to the whole demand in the Lurgi zone on a postage stamp basis.

Unidentified costs

The Draft Decision reduced the 20% provision for contingencies to a provision for unidentified costs of 10%. GasNet accepts the use of the term "unidentified costs" to describe this category of cost.

However, GasNet submits that a 20% allowance is appropriate given that section 8.20 of the Code only requires that the forecast capital expenditure "is *reasonably expected* to pass the requirements in section 8.16(a) when the New Facilities Investment is forecast to occur". The Code does not require that GasNet demonstrate that the proposal meets the tests in section 8.16(a), merely that there is a reasonable basis to expect that they will meet the tests at the time the investment is made.

Different variables apply to each new facility and as yet, sufficient design work has not been completed to allow GasNet to narrow the range of those variables. Further, the facilities will also not be constructed for some years. As a consequence, it is impossible to realistically estimate all cost elements before the design has been completed. In these circumstances GasNet submits that a 20% allowance is reasonable.

4.6 Pakenham loop (DD section 3.3.4.3(v))

Draft Decision

The Draft Decision requires that GasNet demonstrate how this project passes the system integrity test, and in particular how high velocities can impact the safety or integrity of services.

GasNet Response

GasNet notes that the Draft Decision has accepted that the Pakenham loop passes the prudent investment test. This is based on Sleeman Consulting's statement that maximum gas velocities should not exceed 25 m/s at 2760 kPa, and that forecast gas velocities approach this limit in 2009.

This view is supported by standard texts such as Menon.[4] However, Menon also advises that operational velocities should not normally exceed 50% of the maximum recommended velocity.[5] On this basis, the forecast gas velocity of 22 m/s in 2009 is well in excess of the recommended operational velocity at 2760 kPa of 12.5 m/s.

The Pakenham loop project also passes the system integrity test. This is because the pipeline will exhibit high gas velocities by 2009, well in excess of the operational velocity of 12.5 m/s recommended by Menon, and approaching the maximum recommended velocity of 25 m/s.

This augmentation is required to maintain the integrity (ie continuity and reliability) of the services because:

(a) high gas velocities can lead to excessive noise and vibration, and pressure cycling in the gas pipeline (although the effects of high gas velocities will vary with the operational conditions of the pipeline). This in turn can lead to pipeline fatigue, the possibility of failure of pipeline welds, and damage to instrumentation and meters. If pipeline contaminants are present, there is also a risk of erosion and damage to instrumentation; and

(b) this requires that the pipeline be operated in a state which is consistent with accepted standards and good operating practice, which would not be the case without the augmentation.

4.7 Stonehaven compressor (DD section 3.3.4.3(vi))

GasNet Proposal

GasNet has identified the need for a compressor on the South West Pipeline, in the vicinity of Stonehaven, for the purpose of relieving capacity constraints on injections from Port Campbell (Iona) into Geelong and Melbourne. The project, with an approximate cost of $26 million, is proposed for 2012, which is the optimal timing for the project based upon forecasted capacity limitations on the PTS.

Draft Decision

The Draft Decision states that the Stonehaven compressor is not reasonably expected to pass the prudent investment test.

The Draft Decision contends that the supporting report from VENCorp is only indicative, is very sensitive to minor changes in the input assumptions, and could produce different results with further analysis. Further, the Draft

[4] E Shashi Menon Gas Pipeline Hydraulic section 2.7.

[5] Ibid, p 40.

Decision notes that alternative options have not been evaluated, and further considers that alternative options as suggested by Sleeman Consulting may be more cost effective.

GasNet Response

The Commission has relied heavily on the views of its expert consultant. Sleeman Consulting has stated that “the conditions (in the Code) cannot be satisfied until such time as the PTS constraints have been quantified, options for addressing those constraints properly investigated and thorough economic analysis completed to determine which option is optimal.”

In the opinion of the consultant, the need for an augmentation has not been established nor quantified, and a review of alternative solutions to any identified constraints has not been undertaken. Further, Sleeman Consulting argues that, in the event that there was an identified need for augmentation of the system, then a modest increase in pressures at the Iona inlet would be very likely to address the capacity constraint with minimal additional expenditure.

In response GasNet submits that:

(a) it has provided a cost/benefit analysis that demonstrates that the Stonehaven compressor is economically viable in 2012;

(b) the analysis is sufficient to meet the requirement of the Code in respect of forecast capital expenditure, which is that the section 8.16 tests can be “reasonably expected” to be met; and

(c) there is no low cost alternative to Stonehaven, and hence a revenue provision in the tariffs is justified, whether or not subsequent analysis shows an alternative investment is superior to Stonehaven.

Project cost/benefit analysis

The Stonehaven compressor project was justified using a system-wide cost/benefit analysis prepared by VENCorp. The analysis was based on a similar methodology to that applied to the Corio pipeline and accepted by the Commission in 2006.

The cost/benefit analysis evaluated the benefits of reduced load curtailment and system security against the cost of constructing the Stonehaven compressor. The results were based on the costs and benefits derived in the earlier Corio pipeline study, where the benefits were measured on the basis of a reduction in involuntary load curtailments. However, the Corio loop analysis assumed that 50% of the benefits would be derived from an increase in system capacity, and 50% from an increase in system linepack. As the Stonehaven compressor was deemed to provide no additional linepack, VENCorp took only 50% of the total benefits arising from an increase in capacity, and adjusted them to a later date.

VENCorp’s cost/benefit study was a conservative analysis which did not attempt to value the associated competition benefits arising from greater injections at Port Campbell. The VENCorp report concluded that the compressor should be installed for winter 2013, but GasNet has demonstrated that, by using a lower discount rate in the present value calculations (equal to the regulatory WACC) and allowing for competition benefits, the optimal timing is brought forward to at least 2012.

Given the time available to prepare the report, and the five year timeframe for the evaluation, the report only attempted a high level analysis. However, GasNet submits that the level of detail in the report is more than sufficient to justify a small revenue provision in the GasNet tariff (and noting that an approval of this project does not bind the regulator to roll the asset into the Capital Base).

Sleeman Consulting also presented a peak day supply/demand analysis which suggests that a compressor is not needed by 2012. This analysis used a demand forecast which excluded the gas-fired power generation load. On the other hand, the VENCorp analysis did include this load within the cost/benefit analysis, and an appropriate cost was attributed to curtailment of gas-fired power generation demand. In addition, the VENCorp analysis was conducted over the whole winter using a Monte Carlo simulation of each day, rather than just on the peak day. For these reasons, the consultant's results cannot be compared to the VENCorp results.

Code requirements

In order for capital expenditure to be rolled in to the Capital Base, it is necessary to demonstrate that the capital expenditure does not exceed "the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with good industry practice, and to achieve the lowest sustainable cost of providing Services". However, with respect to forecast capital expenditure, the Code (section 8.20) only requires that the expenditure "is *reasonably expected* to pass the requirements in section 8.16(a) when the New Facilities Investment is forecast to occur".

The fact that a capital expenditure project may be approved for inclusion in the forecast revenue requirement does not necessarily mean that the project will be rolled into the Capital Base. The project must still pass the Code tests in section 8.16 *ex post* at the time of the next reset, when all historical projects are reviewed before they can be included in the Capital Base. As a result of changing circumstances in the market, the actual project may differ considerably from the initial forecast proposal - it may cost more or less or an alternative project may proceed. In approving a forecast capital expenditure at the beginning of a reset, the regulator is not giving its regulatory *imprimatur* to the specific project, it is simply allowing a provision for higher revenues during the Access Arrangement Period so that the Service Provider is not out-of-pocket if and when a project does go ahead.

Hence, given the limited consequences flowing from the regulatory approval of a forecast capital expenditure project, the Code only requires a "reasonable expectation" that the project will go ahead and meet the requirements of section 8.16.

In assessing whether an expectation is reasonable, a regulator should also take account of the timeframe of the forecast. For example, it is not possible to justify a 2012 project with the same level of detail and rigour as a 2008 project. The further out a project is forecast, the greater is the level of uncertainty surrounding the details of the project. However, as a *quid pro* *quo*, the further out a project is forecast, the lower the impact on forecast revenues.

GasNet believes that the Draft Decision has imposed too high a standard for the Stonehaven compressor station project which is not justified under the relevant sections of the Code. When allowance is made for the timeframe for the project, and the limited impact on tariffs, GasNet believes it is reasonable, at this time, to expect that the project will meet the prudent investment test.

Alternative options

It should be noted that the Stonehaven option was selected as the most likely next stage of the South West Pipeline augmentation based on ongoing system planning processes at GasNet and was confirmed by VENCorp.

Given that the VENCorp cost/benefit study was a high level analysis, it is reasonable that there was no detailed consideration of alternatives. If subsequent analysis demonstrates that there is a superior alternative, then the revenue provision made for the Stonehaven compressor is equally applicable to that alternative project. It will then be up to GasNet to justify the alternative project *ex post* at the end of the next reset period, or to submit a section 8.21 *ex ante* application before the end of the period, in order for the project to be rolled-in to the Capital Base.

Sleeman Consulting has argued that a modest increase in gas pressure at Iona will increase the efficiency and capacity of the South West Pipeline. This is a reference to the fact that the capacity of the South West Pipeline is based on the assumption of inlet pressures of 6,500 kPa, whereas the pipeline can accept pressures up to 10,000 kPa. The net result is that injections at Port Campbell can be increased from 220 TJ/day to 260 TJ/day.[6]

However, VENCorp also notes that the impact of higher Port Campbell injections is to back off Longford injections, so that the total capacity of the PTS is unchanged.[7] The PTS has operating boundaries which cannot be increased without additional compression or linepack.[8] Any of these options involve additional capital expenditure and hence justify a revenue provision in the tariff.

Sleeman Consulting also suggests that improved operational management or flow control valves could avoid these operational boundaries. However, no specific proposals have been put forward for evaluation, and GasNet believes the operational issues can only be overcome with further compression or looping.

GasNet understands that VENCorp is undertaking a detailed market benefits assessment of the Stonehaven compressor which is due to be completed in February. GasNet requests that the Commission take the findings of this analysis into account in its final decision, even if it results in a delay in the issue of the final decision.

6 VENCorp APR 2006, p 29.

7 VENCorp APR 2006, p 33.

8 VENCorp APR 2001, p 37.

4.8 Carisbrook loop (DD section 3.3.4.3(viii))

Draft Decision

The Draft Decision has not approved the project on the basis that it does not pass the prudent investment test because neither Sleeman Consulting nor VENCorp support the project:

(a) Sleeman Consulting agrees that a constraint will not arise provided that the recommendations of the Northern zone augmentation are completed; and

(b) VENCorp believes the constraints will not arise on the pipeline within this regulatory period.

GasNet Response

GasNet notes that whilst there is agreement between VENCorp and Sleeman Consulting as to the unusual nature of gas flows and pressures at Carisbrook, there is a disagreement as to the cause and ultimate consequences of these flow and pressure fluctuations.

Both VENCorp and Sleeman Consulting believe that these fluctuations will not grow over time and will be manageable with existing equipment, although Sleeman Consulting notes that his view assumes the completion of the Northern augmentation.

However, GasNet remains of the view that these unusual fluctuations are a cause for concern and should be addressed by construction of a reinforcing loop in AA3.

4.9 Acquisition of easements for the Brooklyn Wollert loop (DD section 3.3.4.3(ix))

GasNet proposal

GasNet has identified a requirement for early acquisition of an easement for the Brooklyn Wollert pipeline. This is to avoid the risk of urban encroachment on the planned route, leading to a higher cost of construction of the pipeline when it is required.

The expected cost of acquiring the easement is $5.37 million in 2010.

Draft Decision

The Draft Decision states that this project is not reasonably expected to pass the prudent investment test on the basis that GasNet has not satisfactorily demonstrated a need for the pipeline, nor substantiated the likelihood of urban encroachment.

The Draft Decision notes that if GasNet is able to demonstrate the need for the high pressure link between Brooklyn and Wollert, then there may be scope to include the proposal in a speculative investment fund.

GasNet Response

GasNet understands that VENCorp is carrying out further work on the benefits of early acquisition of easements between Brooklyn and Wollert. GasNet's approach to the easement acquisition will depend on VENCorp's analysis. If it supports the need for the loop in the future, GasNet submits that the acquisition of the easement in 2010 is justified.

GasNet has sought to acquire the easement early to avoid urban encroachment which GasNet believes will lead to a higher cost of construction in the future. If it is accepted that the Brooklyn Wollert loop will be required in the future, it is users who will ultimately benefit from the early acquisition and resulting cost savings. From a cost perspective, GasNet itself is indifferent as to whether the easements are acquired in AA3 or a later period.

In order to approve the pre-acquisition of the Brooklyn Wollert easement, the Commission needs to be satisfied on the following three issues:

- a high pressure link between Brooklyn and Wollert is reasonably expected to be required and can be justified;
- there is a threat of urban encroachment which will lead to a higher cost of construction in the future; and
- acquiring the easement before the pipeline link is needed will result in the lowest sustainable cost of providing the service.

Each of these issues is addressed below.

The need for the Brooklyn Wollert loop

As noted above, the VENCorp report will include analysis on the need for the Brooklyn-Wollert loop and will be provided shortly. However, GasNet has provided further details of the loop below.

The Brooklyn Wollert loop is a high pressure pipeline connecting the Wollert and Brooklyn compressor stations through predominantly rural or lightly occupied land. It consists of 71 km of 600 mm pipeline, of which 33.5 km is within existing easements, and 37.5 km is along a greenfields route.

In conjunction with the Brooklyn Lara pipeline, the project will provide a high pressure, high capacity pipeline connecting the South West Pipeline, the Brooklyn and Wollert compressor stations, and Dandenong. It will enable high volume interchanges between the east and west of the system (with improved management of Longford and Port Campbell injections), improved supply to all parts of the metropolitan area, and increased linepack. The anticipated cost of the pipeline is $117 million.

A description of the pipeline and the pipeline route is provided in Attachment 2.

Easement acquisition for the Brooklyn Wollert loop

The selected easement consists of 33.5 km in existing easements and 37.5 km along a greenfield route. The pipeline route corridor that has been selected is the only feasible route for construction of a gas pipeline. The greenfield route has been selected to avoid land within the Melbourne 2030 plan, and is predominantly within "green wedge" zones. A number of alternative routes have been analysed but they have been rejected for a variety of reasons.

Indeed, had the pipeline been constructed 10 years ago, the pipeline route would have been 10 km shorter. Rezoning and subsequent development of Craigieburn and surrounding areas has meant it is no longer possible to construct a high pressure pipeline along a shorter route.

It is estimated that if urban encroachment continues, then the cost of the Brooklyn Wollert loop will be at least $20 million higher in. This would justify the early acquisition of an easement in 2010 at a cost of between $11.0 million (for construction in 2020) and $14.8 million (for construction in 2015).

A detailed discussion of route selection options and costs is presented in Attachment 3. On the basis of this evidence, GasNet believes it has established that there is a risk that urban encroachment will lead to a significant increase in the cost of the pipeline.

Lowest sustainable cost of providing the Brooklyn Wollert loop

It should be noted that this project is the first proposal from GasNet for early acquisition of an easement. It is likely that this issue will grow over time as new areas of Melbourne are opened up to development.

The Vision 2030 Report to the Victorian government highlighted the problem of providing infrastructure in a growing city. In response, VENCorp has established a Sites and Easements project to evaluate the specific issues and strategies to deal with urban encroachment on gas and electricity sites and easements. The Brooklyn Wollert loop is one of the projects that is being examined by the project team.

VENCorp is in the process of preparing a report on the benefits of early acquisition of the Brooklyn Wollert easement within a "real options" analytical framework. This will be provided shortly.

Cost estimate

The cost estimate for the acquisition of 33.5 km of easement and a pipeline licence is contained in Attachment 2. The total cost of $5.37 million is approximately 4.6% of the total cost of the pipeline. This compares with owner's costs on the Brooklyn Lara Pipeline of 4.2%.

Speculative investment fund

The Commission considers that there may be scope to include this project in a speculative investment fund.

If GasNet acquired this easement in 2010 at cost of $5.4 million, and if it was not approved to be rolled into the Capital Base, then GasNet could include this investment in a speculative fund. This fund would earn no returns until the Brooklyn Wollert loop was constructed in that easement, at which time GasNet could apply to have the easement rolled into the Capital Base. The

Code allows the value rolled into the Capital Base to include a capitalised return over the period between when the investment is made and when it is included in the Capital Base.

However, whilst this option is available, GasNet does not consider that it is appropriate. This is because Users will ultimately bear the higher cost to acquire the easements in the future as GasNet would be able to roll the costs to acquire the easements into the Capital Base in full provided they meet the tests in section 8.1.6(a) at the relevant time. Accordingly, GasNet has no incentive to make a speculative investment.

That said, it is appropriate for this cost of the early acquisition to be charged to users through the reference tariff. Users are the ultimate beneficiaries of the early investment in an easement. Further, it does not expose any individual user to the same level of risk as applying the whole speculative risk to one company - the financial burden will be spread over a large number of users.

It should be noted that the concept of early acquisition of sites and easements is accepted within the regulated electricity transmission industry, and a number of such investments have been approved by regulators. For example, the AER acknowledged in its Final Decision in relation to Powerlink's revenue cap that it was good industry practice to acquire some easements before they are required for augmentation if it is likely to result in lower costs to customers in the long-term.[9]

5 Refurbishment/Upgrade Capital Expenditure

5.1 General overview (DD section 3.3.4.4)

With the exception of the Wollert compressor station upgrade and miscellaneous refurbishment capital expenditure, the Draft Decision agreed that all of GasNet's proposed refurbishment capital expenditure meets the system integrity test. However, in each case (except the Brooklyn compressor station refurbishment), the Draft Decision approved an amount of capital expenditure which is less than that proposed by GasNet.

5.2 Gas heating facilities (DD section 3.3.4.4(i))

Draft Decision

The Draft Decision states that the amount of the investment which passes the prudent investment test is $7.25 million rather than the $9.2 million proposed by GasNet. This is on the basis of:

(a) the removal of $0.34 million included for a gas chromatograph at Wandong because it has not been identified as a requirement by VENCorp; and

[9] AER Final Decision, Powerlink Queensland transmission network revenue cap 2007-08 to 2011-12, 14 June 2007, p 25. See also AER Draft Decision ElectraNet revenue cap, 2008/09 - 2012/13, November 2007, p 84.

(b) Sleeman Consulting's opinion that the allowance for owner's costs should be reduced from between 15 and 17% to 10%, and that the allowance for contingencies of 20% should be replaced with an allowance for unidentified costs of 10%.

GasNet Response

With respect to the Wandong gas chromatograph, GasNet accepts that this has not been identified by VENCorp as yet. GasNet will withdraw this proposal because if VENCorp requires a chromatograph subsequently, this will constitute a Regulatory Event for the purposes of the Access Arrangement.

With respect to the reduction in the allowance for owner's costs, GasNet notes that Sleeman Consulting's description of the activities covered by this cost category includes project and site management, commissioning, spare parts, updating of procedures, and staff training. However, the design function has been excluded from this list. Design is a critical function in the provision of complex facilities such as gas heaters. Each heater facility is a one-off design which must be individually tailored to a unique purpose and incorporated within unique regulator configurations at each site. On this basis, GasNet submits that provision for an allowance of 15-17% is reasonable and complies with section 8.16(a)(i) of the Code.

Sleeman Consulting has also reduced the 20% provision for contingencies to a provision for unidentified costs of 10%. GasNet accepts the use of the term "unidentified costs" to describe this category of cost.

However, GasNet submits that a 20% allowance is appropriate given that section 8.20 of the Code only requires that the forecast capital expenditure "is *reasonably expected* to pass the requirements in section 8.16(a) when the New Facilities Investment is forecast to occur". The Code does not require that GasNet demonstrate that the capex proposal meets the tests in section 8.16(a), merely there is a reasonable basis to expect that they will meet the tests at the time the investment is made.

Different variables apply to each new facility and as yet, sufficient design work has not be completed to allow GasNet to narrow the range of those variables. Further, the facilities will also not be constructed for some years. As a consequence, it is impossible to realistically estimate all cost elements before the design has been completed. In these circumstances GasNet submits that a 20% allowance is reasonable.

5.3 City gate works (DD section 3.3.4.4(ii))

The Draft Decision states that the amount of the investment which passes the prudent investment test is \$6.18 million rather than \$6.68 million as proposed by GasNet. This is on the basis of Sleeman Consulting's opinion that the allowance for contingencies of 20% should be replaced with an allowance for unidentified costs of 10%.

GasNet Response

Consistent with its response in section 5.2 above, GasNet accepts the use of the term "unidentified costs" to describe this cost, but submits that the 20% allowance is reasonable and complies with section 8.16(a)(i) for the same reasons given in that section.

5.4 Pipeline upgrades (DD section 3.3.4.4.(iii))

Draft Decision

The Draft Decision approved all of GasNet's proposed pipeline upgrade capital expenditure, with the exception of the $2.0 million provision for pipeline risk assessments. Consequently, the Draft Decision has accepted a prudent expenditure of $7.65 million.

The Draft Decision accepts that the provision of $2.0 million for pipeline risk assessments is an allowance for necessary capital expenditure that arises as a result of work identified by pipeline risk assessments. However, as the works have not been identified, the Draft Decision considers that this provision does not meet the requirements of the prudent investment test in the Code.

GasNet Response

GasNet has made a provision of $2.0 million over 5 years for works required to bring GasNet pipelines up to the required standard following pipeline risk assessments. This amounts to $0.4 million per annum. Sleeman Consulting has indicated that making provision for this amount is reasonable.

GasNet accepts that the specific works to be undertaken have not yet been identified. However it is reasonable to expect that some work will arise during the course of risk assessment which will require capital expenditure.

It is not clear why the Draft Decision states that provision for unidentified projects is unacceptable under the Code. Section 8.20 of the Code requires that forecast capital expenditure be allowed if it is reasonably expected to pass the tests in section 8.16(a) of the Code. It is not uncommon for regulators to approve amounts for unidentified capital expenditure under a "business-as-usual" heading or based on historical experience. The relevant issue is whether it is reasonable to expect that some expenditure will be required on as yet unidentified projects, rather than that a specific project should be identified, described and justified.

For example, a gas distributor may identify meter replacement as a legitimate project, even though they cannot identify the specific meters to be replaced until the project commences.

Therefore GasNet believes that a small allowance of $0.4 million per annum to improve the safety and integrity of gas pipelines is a prudent expense and should be approved.

5.5 Safety and security systems (DD section 3.3.4.4(iv))

Draft Decision

GasNet proposed $2.93 million for security upgrades at sensitive sites on the PTS. In addition, GasNet proposed $1.32 million of safety expenditure to replace or upgrade electrical equipment identified by the hazardous area review. These projects are scheduled for 2008 and 2009.

The Draft Decision accepts that the security expenditure passes the prudent expenditure test. However the Draft Decision does not accept that an allowance for replacement or upgrade of unidentified electrical equipment can be characterised as new facilities investment for the purposes of the prudent investment test in the Code. The Draft Decision has rejected the proposed expenditure on the hazardous area review project because the expenditure is a provision for as yet unidentified projects. The Draft Decision does not consider that this satisfies the relevant Code test for a prudent investment.

GasNet Response

The Draft Decision appears to have rejected the capital expenditure on the basis that the specific investments have not been identified, and therefore do not meet the requirements of the Code.

In GasNet's opinion, this is an incorrect interpretation of the Code. Section 8.20 of the Code requires that forecast capital expenditure be allowed if it is reasonably expected to pass the tests in section 8.16(a) of the Code. This does not require that a specific facility be identified and justified before the event. It only requires that an amount of investment is expected to be incurred, which once incurred, would be judged to be prudent.

The work flowing from the hazardous area review would fit this description.

The interpretation employed by the Draft Decision would be unworkable in practice, since many legitimate expenditures made by regulated companies fall into the category of unidentified "business-as-usual" projects. These projects have been approved by regulators in the past.

5.6 Wollert compressor station (DD section 3.3.4.4(vi))

GasNet accepts the Draft Decision's approach.

5.7 Other compressor station upgrades (DD section 3.3.4.4(vii)

Draft Decision

The Draft Decision does not consider that the replacement of the Iona control system is a prudent investment and has not accepted the $1.62 million GasNet proposed for this investment. This is on the basis of the Draft Decision's view that the existing control system at Iona, which was installed in 2001, is likely to be serviceable beyond 2012.

GasNet Response

GasNet notes that some controls were installed in 1999 when the regulator station was constructed, and the remainder in 2001 when the compressor unit was added. Therefore, the life of the units at replacement in 2012 will vary between 11 and 13 years, which in GasNet's view meets the prudent investment test. Consideration should also be given to technological change, and the uncertainty of on-going support for the equipment.

A near miss occurred circa 2005 when a field device failure led to shutdown of the Iona city gate, which is the sole supply to the Western system. This prevented operation of both the compressors and the city gate until averted through intervention from Dandenong using remote diagnostics. Had the RTU failed or the personnel not been available this would certainly have led to significant customer outage.

The service life of any control system is becoming significantly shorter particularly where it is required to interface with new technology such as current generation communications, SCADA control systems, PCs etc. The proposed Iona control system upgrade will address security of supply issues while improving remote support.

5.8 Other refurbishment and upgrades (DD section 3.3.4.4(viii))

Draft Decision

The Draft Decision rejected GasNet's proposed expenditure of $4.3 million on minor refurbishments and upgrade projects over AA3 on the basis that GasNet did not detail or substantiate these projects. Therefore neither the Commission nor its expert consultant were able to assess whether the capital expenditure would pass the prudent investment test.

GasNet Response

Although GasNet did not attempt to substantiate these projects in detail, a list of the relevant projects and their costs was provided to the Commission.

In GasNet's opinion, it should not be necessary to substantiate the detail of "business-as-usual" expenditure. An expenditure of 0.15% of the Capital Base each year for various unidentified projects is a reasonable expectation, and GasNet would expect it to be approved without further substantiation.

At the 2002 reset, the Commission approved expenditure on minor capital expenditure of $5.56 million or $1.1 million per annum. The Commission accepted this unidentified minor maintenance capital expenditure on the basis that it represented only 0.2% of the ORC and was comparable with similar expenditures on other transmission pipelines. In general, it is reasonable to expect capital expenditure to be comparable to the amount of depreciation claimed on particular asset classes, even though the capital expenditure has not been specifically identified. This was the position taken by the Commission in the 2002 Final Decision in respect of minor capital expenditure.

The specific projects in this category are described below.

Buildings

GasNet proposes to spend $1.78 million on building works over AA3. This consists of $1.14 million for an expansion of office space and associated furniture, and $0.64 million for general maintenance capex.

The annual maintenance expenditure is approximately 1.7% of the estimated ORC value of GasNet's buildings, and represents an amount less than the depreciation claimed on these assets. On this basis GasNet submits that the $0.64 million is a prudent allowance.

The office expansion capex of $1.14 million is approximately only 15% of the estimated ORC value of buildings representing a relatively minor expansion of office space. The expansion is required to accommodate additional staff and equipment associated with the increased annual workload, and for staff and contractors associated with the substantially larger capital expenditure program.

Corporate IT & office systems

GasNet proposes to spend $0.86 million on upgrades and replacements of IT hardware and software, communication and data acquisition systems. This is equivalent to an annual cost of 18% of the estimated replacement costs of IT assets, which is a reasonable amount considering the 4 year technical life given to these assets.

Minor system refurbishments and upgrades

A further $1.66 million is planned to be spent on various minor projects over the next 5 years.

These projects include:

(a) Replacement of odorant pumps at Longford - $0.22 million.

The Longford odorant system provides a single point of odorant injection for 90% of the gas entering the PTS.

The odorant system was replaced in 1996-1997 and has been operating effectively since, however over the past few years failures of the primary pump have become more prevalent and replacement of the system is believed to be prudent at this time.

If odorant is not injected in the correct quantities, the system would become unsafe. Recently VENCorp had to institute a safety intervention when unodorised gas was inadvertently injected at Iona.

(b) Replacement of chromatographs and installation of Welker sample probes - $0.33 million

GasNet originally installed six chromatographs in 1996. The forecast allows $0.25 million for the replacement of the two chromatographs located at Dandenong City Gate and Terminal station which have been damaged on a number of occasions by pipeline liquids. An amount of $0.08 million has been forecast for the installation of five

Welker insertion probes which are designed to prevent liquids entering the new gas chromatographs.

(c) Removal and treatment of asbestos - $0.20 million

GasNet has been conducting routine audits of asbestos material located within building structures over the past ten years. In 2011, GasNet plans to remove the asbestos roofing material located on buildings surrounding Dandenong City Gate and Terminal station. The asbestos roofing is to be replaced with Colorbond roof sheets.

(d) Replacement of RTU units - $0.51 million

GasNet currently has 23 RTUs (Remote Terminal Units) installed at line valve and regulator stations throughout the PTS. These units were installed as part of the GasMan project in 1996 and the Winter 99 project (following the Esso explosion). The five oldest RTUs at critical sites have been selected for replacement during AA3.

Telemetry huts have been incorporated into the RTU replacement program, to facilitate a clean air conditioned environment for the equipment and to facilitate repair of units by field technicians in a safe environment.

(e) Acquisition of test equipment for pressure calibration - $0.20 million

GasNet has identified a requirement to replace two of its 20 year old dead weight testers used for pressure calibration, and to purchase a range of new equipment for additional staff commencing employment.

(f) Replacement of the GasMan radio system - $0.20 million

The GasMan radio systems were originally installed in 1996 on the old Gas & Fuel radio system backbone. This system has slowly deteriorated due to radio system congestion, shortage of available spares and experienced radio technicians with a knowledge of the system. There are currently seven RTUs still using this system for communication, and it is intended that the existing communications be upgraded to a secure 3G service.

6 Capital redundancy (DD section 3.4)

Draft Decision

The Draft Decision rejected GasNet’s proposed amendment to clause 4.6 of the proposed access arrangement on the basis that it would redistribute the risk of redundancy from GasNet to users and thereby weaken the incentive for GasNet to make appropriate investment decisions. It also suggested that the ambiguity in determining whether regulated services have been “significantly” reduced also weakened the incentives faced by GasNet.

GasNet Response

While GasNet does not necessarily agree with the analysis set out in the Draft Decision on this issue, it does not propose to pursue the relevant amendment to its Access Arrangement at this stage.

7 Depreciation

7.1 Longford pipeline (DD section 3.5.5.1)

Draft Decision

The Draft Decision has accepted all of GasNet's positions in relation to the economic life of the pipelines which comprise the PTS, with the exception of the Longford to Dandenong pipeline. For this pipeline, the Draft Decision requires GasNet to use an economic life of 2029 which matches the technical life of the pipeline.

As part of GasNet's revised access arrangement for AA2, the Commission accepted that the Longford pipeline should have an economic life that was 6 years shorter than its technical life of 2029. The shorter life of 2023 was justified by GasNet on the basis of a report from Saturn Corporate Resources. A key factor in this decision was an assessment of the remaining life of the gas reserves in the Gippsland basin.

However, the Draft Decision now states that there is evidence of an increase in the level of Gippsland gas reserves, and on the basis of this evidence the Draft Decision requires that the economic life be set at the technical life of the Longford pipeline, being 2029.

The Draft Decision relies on the following points to come to this conclusion:

- The Gippsland reserves of 8000 PJ assumed by the Saturn report will not be depleted by 2023 unless annual production is very high, of the order of 400 PJ/yr. It notes that production in 2006 was only 232.3 PJ, and that ABARE forecasts it to reach no more than 392 PJ/yr.

- The ABARE forecast shows Gippsland continuing to produce beyond 2030.

- Esso Australia has stated that production will continue for approximately another 30 years.

- Esso Australia has significantly upgraded its Gippsland reserves in 2006, by 53.9%. Total reserves are 9000 PJ, greater than the 8000 PJ assumed by the Saturn report.

- As a result, it is unlikely that reserves would be depleted by 2023.

- In addition, there are gas networks and large consumers in the region served by the pipeline who would still require gas supply.

GasNet Response

GasNet believes that the economic life of the Longford pipeline should be retained at 2023. This is based on its view of the economic factors affecting the future viability of the Longford pipeline, as explained in its 2002 submission for AA2, and on the fact that there has been no material change since that time.

Indeed, there is now reason to believe that economic risks to pipelines have increased since 2002. It is generally accepted that there is a greater likelihood that the government will embark on a post-Kyoto carbon reduction strategy which could lead to a significant increase in gas usage post-2012, and more rapid depletion of known reserves. There are too many variables to make a confident prediction of these events, but there is no doubt that the risk of earlier depletion of the Gippsland basin has increased, and it would therefore be prudent to err on the side of a shorter life.

Code requirements

The Code requires that each asset or group of assets which forms 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, consistent with its 2002 submission in relation to AA2, 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.

The determination of the relevant economic life is not an exact science. It will depend on a number of variables in the future which are unknown at this stage. However, as the Commission said in its 2002 Final Decision, the difference in tariffs between an asset life of 2023 or 2029 is relatively small. Accordingly, GasNet submits that its proposal is reasonable for the purposes of the Code and there is no reason to depart from the current asset life.

Consistent with its 2002 Final Decision, the Commission should take into account the section 2.24 factors. In its 2002 Final Decision, the Commission considered GasNet's interests and the interests of users under sections 2.24(a) and (f) of the Code. In accepting GasNet's proposed economic life, the Commission placed greater weight on GasNet's interests because the issue was of greater significance to GasNet.

GasNet submits that this remains the case. Adopting a depreciation period beyond the economic life of the asset poses a substantial risk to GasNet that it will not be able to recover its investment. If a pipeline becomes unviable before the asset value is fully depreciated, then the asset owner will not be able to recover the remaining undepreciated asset value. These are asymmetric risks which are not compensated for through the approved WACC (since the WACC only compensates for diversifiable risk, whereas an over-estimate of economic life is a non-diversifiable risk).

In contrast, there is no long-term disadvantage to consumers arising from a particular choice of the economic life, since the present value of the future revenue stream is independent of the depreciation period, and so the choice of one period over another is a zero-sum game.

Nothing material has happened to change the conclusion of the Saturn report

The Draft Decision has quoted from EnergyQuest, the Esso Newsroom, and the recent ABARE Report, which all make reference to gas reserves and production from the Gippsland basin. The Draft Decision concludes that the most recent reserves estimate of 9,000 PJ is significantly higher than the estimate of 8,000 PJ quoted in the Saturn report of 2002, and justifies an extension in the economic life of the Longford pipeline.

However, the analysis contained in the Draft Decision focuses too much on only one aspect of the argument presented by the Saturn report, which is gas reserves in Gippsland. The Saturn report was a probabilistic analysis of a range of factors affecting economic life, of which Gippsland reserves was only one part. The Saturn report assumed official reserves of 8000 PJ, but allowed for the possibility of up to 12,000 PJ of actual reserves. A range of other uncertainties were also considered, such as the size of the Otway and Cooper basin reserves, and demand in other states. These factors are all interlinked, since for example, lower Cooper basin reserves would lead to greater exports from the Gippsland basin to NSW, resulting in more rapid depletion of this resource.

The Saturn report did not arrive at an economic life of 2023 by a simple deterministic analysis of Gippsland reserves depletion. The Saturn report derived probabilities of reductions in the technical life based on a range of possible reserve levels in the context of the supply and demand situation in the south eastern states. The Saturn report then included the effect of other factors that bear on economic life to derive their final recommendation.

Other relevant factors such as Cooper basin reserves and demand forecasts may have changed, and this has not been factored into the Draft Decision's analysis. As an example of recent changes in the demand and supply situation, GasNet understands Esso Australia intends to install a new gas processing plant at Longford, and a new compressor is being installed on the EGP to Sydney, which will enable greater exports to NSW and more rapid depletion of the Gippsland basin.

Esso has stated that "there is also approximately more than 30 years of gas still to be produced from Gippsland". This statement does not indicate what production levels are assumed for this calculation. It is standard practice in the industry to refer to a reserves-to-production ratio at current levels of production. However, it is clear that depletion of the reserves will occur sooner if production levels increase over time.

The 2006 ABARE energy projections present a scenario in which Gippsland production continues beyond 2030. This is a single deterministic scenario, and would be heavily influenced by changes in the input assumptions. The key assumption which drives ABARE's Gippsland result is the huge increase in Coal Seam Gas (CSG) production from 58 PJ in 2004/5 to 339 PJ by 2029/30. By supplying South Australia and NSW, CSG reduces the demand on Gippsland, and extends the life of the reserves.

There is no doubt that this is a possible scenario. Whether it comes to fruition depends on the delivered price of CSG versus the delivered price of Gippsland gas in South Australia and NSW, a factor which is very difficult to predict. However, as pointed out by Saturn, the relevant issue for GasNet is the risks to the viability of the Longford pipeline if this scenario does not eventuate. For example, new CSG production might be more expensive than current production, restricting CSG to Queensland and increasing the rate of depletion of Gippsland. There are many alternative scenarios which could see rapid depletion of Gippsland, all with some probability of occurrence. An allowance must be made for these possibilities, which is the basic theme of the Saturn report. This is all the more relevant given that an error in the economic life estimate is a risk for which GasNet is not compensated.

On balance, GasNet believes that nothing material has changed to justify a review of the Longford pipeline economic life. Moreover, as discussed below, there is reason to believe that a Greenhouse response strategy may actually increase the risks to the economic life of the pipeline.

The uncertainties facing gas infrastructure investments are increasing

As of five years ago it was unclear whether there would be any serious attempt to reduce greenhouse gas emissions in Australia. Since then the political consensus has changed dramatically, and there is now a high likelihood that a post-Kyoto carbon reduction strategy will be implemented. The Labor Party has announced a long-term target of a 60% reduction in CO_2 emissions from year 2000 levels by 2050. This would require a radical restructuring of the energy industry.

It is generally agreed that, as part of this strategy, there will be an increase in natural gas consumption as gas replaces electricity in end-use applications, and gas replaces coal in electricity generation. What is not clear is how fast this transition will occur.

The 2006 ABARE report makes some allowance for increased gas demand in electricity generation. However, there is scope for significantly faster substitution of gas for coal, although at a higher economic cost. If this occurs, then it is likely that local gas reserves will be rapidly depleted.

There are too many possible scenarios to generate meaningful predictions of gas demand and supply over the next 20 years. GasNet does not favour making important economic life decisions on the basis of one scenario, which could be radically altered by relatively small changes in the input assumptions.

The uncertainty created by the need to develop a carbon reduction strategy will inevitably lead to greater risks to the long-term viability of the Longford pipeline, rather than lower risks.

In conclusion, GasNet submits that there is nothing in the Draft Decision to support the conclusion that it reasonable to depart from GasNet's proposal (or that GasNet's proposal is not reasonable).

8 Rate of return

8.1 Risk-free rate (DD sections 4.1.5.4 and 4.1.5.5)

Draft Decision

The Draft Decision accepted all of GasNet's positions in relation to WACC with the exception of the real risk-free rate and debt raising costs.

With respect to the debt-raising costs, the Draft Decision has accepted the advice prepared by Allens Consulting Group in 2004, and has updated the cost estimates. The figure this advice derives is marginally below the GasNet proposal. The Draft Decision has reduced the allowance from 12.5bp to 10.4bp.

The Draft Decision has determined that the yields observed on index-linked bonds no longer provide an appropriate proxy for the real risk-free rate. This is a shift from the principles used in previous Access Arrangements and is based on recent evidence presented to regulators.[10]

The Draft Decision considers that an appropriate proxy can be derived by subtracting a forecast of inflation from the nominal 10-year government bond rate. However, the Draft Decision does not accept that there is an absolute bias in the estimate of the nominal bond rate.

With respect to the forecast inflation rate, the Draft Decision notes that in the absence of the indexed-link bond rate as a valid measure of the real risk-free rate, there is no market-based method to determine inflationary expectations. The Draft Decision has relied on the RBA's policy of targeting inflation within the 2%-3% band. Based on statements made by the RBA, the Draft Decision considers that inflation will be at the top of the band.

GasNet Response

GasNet does not agree with the Draft Decision's proposal in relation to debt raising costs. However, GasNet has not pressed this issue because the Commission has indicated that it will undertake a major review of the appropriate WACC parameters in the near future and because the difference is immaterial to GasNet at this time.

GasNet agrees with the Draft Decision that regulatory decision making must have regard to consistency and continuity. These are major issues for a company contemplating significant investments in the gas transmission system. These investments will have a life covering many decades, and will only be made on the assurance that regulators now and in the future will maintain a stable and consistent approach to regulation.

The main area of current uncertainty in the WACC decision is the treatment of the real risk-free rate. This arises from the lack of liquidity in the index-linked bond market. This market has been a key input in the determination of the real rate of return applied to all regulated utilities in Australia. In the absence of a market-based mechanism to determine the real risk-free rate,

[10] See for example NERA March 2007 Bias in Indexed CGS Yields as a Proxy for the CAPM Risk Free Rate A report for the ENA.

GasNet and other regulated businesses are obliged to rely on the observed nominal risk-free rate, and subtract a consistent forecast of inflation from it.

The key requirement of this method is that the term over which the forecast of inflation is estimated must be consistent with the nominal bond rate. Since it is well established that the risk-free rate should be derived from the 10-year bond rate, it is necessary to derive an inflation forecast over the same period.

The inflation rate is unstable and establishing a 10-year forecast with any degree of robustness is very difficult. However, the Australian Treasury has noted that nominal bond yields have become lower in recent years, and the yield curve has become flatter, which it believes is consistent with a perception of increased macroeconomic stability.[11] That is, investors are willing to lock-up funds for 10 years because they believe the long-term macroeconomic scenario is more stable.

An important reason for this perception of greater macroeconomic stability is the fact that the RBA has successfully instituted a policy of targeting inflation between 2-3%. If investors did not have faith in this policy, then the 10-year bond rate would be higher than it currently is, and the yield curve would be upward sloping.

For this reason, the best 10-year forecast of inflation must be the mid-point of the band targeted by the RBA. Indeed the Australian Treasury has stated:

> "*We therefore recommend that the Commission uses the mid-point of the RBA's target band for inflation (i.e.: 2.5% per annum) as the best estimate of inflation. Since the independence of the Reserve Bank Board in conducting monetary policy was formalised in March 1996, annual inflation has averaged 2.5 per cent.*"[12]

In addition, the RBA has recommended:

> "*Given inflation expectations have been firmly anchored by the Bank's inflation-target regime for some time, a rough estimate of a real risk-free rate would be the nominal government bond yield less the centre of the inflation target band (ie. the nominal yield less 2½ per cent).*"[13]

A thorough review of this topic by CECG has reached the same conclusions, and recommends an inflation forecast of 2.5%.[14]

In arriving at its estimate of 3%, the Draft Decision has relied on the inflation forecasts made by the RBA for the years 2008 and 2009. However, as stated previously, the inflation rate is unstable, and the fluctuations over the next two years are irrelevant to the expected inflation over the next 10 years. It is important to note that GasNet is not attempting to derive a best estimate of

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[11] 7 August letter from Treasury Executive Director, Mr Jim Murphy, to Commission Executive General Manager Mr Joe Dimasi.

[12] Ibid.

[13] 9 August letter from Assistant RBA Governor, Mr Guy Debelle, to Commission Executive General Manager Mr Joe Dimasi.

[14] 'Methodology for estimating expected inflation' CECG, 26 October 2007, submitted to ESC Victoria.

inflation over the next 5 years of the regulatory period. It is trying to derive an estimate of inflation expectations over the next 10 years that is consistent with the establishment of the current 10-year bond rate, for the purpose of deriving a real risk-free rate. It is the real risk-free rate which is the relevant factor in setting the regulatory WACC.

On the basis of the evidence presented above, GasNet submits that the correct estimate of the real risk free rate is the 10-year nominal government bond rate, less an inflation forecast of 2.5%.

9 Non-capital costs

9.1 Workload and scope changes (DD sections 5.1.5.7, 5.1.5.13 and 5.1.5.14)

Draft Decision

The Draft Decision has approved the scope changes proposed by GasNet with the exception of the costs associated with the appointment of a regulatory accountant. The Draft Decision rejected this scope change on the basis that the new Gas Law will not apply to GasNet for AA3 and it was uncertain as to whether the AER would have the power to apply the new information gathering and reporting powers to GasNet before the AA4 period.

In relation to workload changes relating to pipelines, the Draft Decision has reduced the costs proposed by GasNet. The Draft Decision's costs differ from GasNet's because:

- the Draft Decision has omitted the operating costs associated with the Carisbrook, Ballarat and Sunbury loops on the basis that these facilities are unlikely to be approved for the AA3 period;
- the Draft Decision considers that looping of the Wollert to Wodonga pipeline is a more cost effective alternative than the Euroa compressor station proposed by GasNet; and
- operating costs are lower for looping than new pipelines.

In relation to workload changes for compressors, the Draft Decision's view was that the increased size and complexity of a number of compressor units justified an additional allowance for materials and services. However, the Draft Decision discounted GasNet's costs on the basis that neither the Stonehaven nor Euroa stations will be approved by the Commission for AA3.

GasNet Response

Regulatory accountant

GasNet is not aware of the basis for the Commission's conclusion that the new Gas Law will not apply to GasNet throughout AA3. The second exposure draft of the New Gas Law released on 19 July 2007 includes savings and transitional provisions (see Schedule 3). Although under section 19(2) of Schedule 3 GasNet's proposed Access Arrangement must be assessed under the existing law and Code, there is no general provision that the new Gas Law will not otherwise apply to GasNet. Obligations separate to the Access Arrangement, such as ring-fencing obligations and potentially other compliance reporting obligations, will apply to GasNet.

Given that GasNet is likely to incur additional obligations, an allowance to comply with these obligations should be allowed. GasNet also believes that the second exposure draft is a sufficient basis for the Commission to approve these costs in the Final Decision.

Opex associated with capex proposals

GasNet has made further submissions in relation to the capital expenditure proposals which the Draft Decision has rejected. It follows that the associated incremental workload costs associated with that forecast capital should also be approved, particularly in relation to the operating cost of the Euroa and Stonehaven compressors. GasNet now proposes that the associated operating costs for these facilities should be 2.2% of the capital expenditure. This is based on the observed compressor operating cost of 2.9%, adjusted to 75% as proposed by Ross Calvert Consulting to recognise the recent escalation in facility costs.

9.2 Fuel gas (DD section 5.1.5.15)

Draft Decision

The Draft Decision proposes to include the base year's (2006) fuel gas costs in GasNet's forecast operating and maintenance costs with any changes to be treated as a pass through event. The Draft Decision also intends to impose a condition on GasNet that it must tender for its fuel gas requirements.

GasNet Response

GasNet has no objection to including fuel gas costs as a pass through event. However it does not consider that the base year's (2006) fuel gas costs should be used as the forecast for the AA3 period on the basis that they are not a reliable base for the calculation of the AA3 tariffs.

Since 2006, a number of compressor refurbishments and new compressors installations either have or will be undertaken which will lead to a difference in the amount of fuel gas consumption. There will also be greater injections from Iona and therefore there will be a change in flow patterns and usage of compressors. In addition, a number of gas heaters will be installed at new locations on the system.

Rather than use the 2006 base year costs as the forecast, GasNet proposes that the tariffs be based on a best estimate of the fuel gas costs over the AA3 period with any changes to that forecast to be treated as a pass through event. This approach will avoid any unnecessary tariff shocks if there is a significant difference between the 2006 fuel gas costs and the actual costs during the AA3 period. It will also minimise the risk that GasNet will be unable to recover a portion of a positive pass through amount due to the 2% tariff rebalancing constraint.

GasNet's revised fuel gas forecasts for the AA3 period are set out below. The revisions from the forecast given by GasNet in its Submission are primarily due to an optimization of compressor fuel usage between Wollert and Euroa compressor stations, and to changes in GPG demand (principally at North Laverton) arising from the ACIL report to the Commission. A detailed compressor fuel use model has been provided with this submission.

Table 9.1: Revised fuel gas use

Fuel Use TJ	2008	2009	2010	2011	2012
Revised Proposal	657.8	635.3	651.1	664.2	696.6

If fuel gas costs are to be treated as a pass through, it is no longer necessary to apply an offsetting factor to the revenue control formula. Therefore, GasNet proposes that the weather adjusted volume in the reserve control formula be replaced with:

WAAV = VW + TS x (Target EDD - Actual EDD)

9.3 Corporate overheads (DD sections and 3.2.5.2(ix) and 5.1.5.16)

Draft Decision

The Draft Decision proposes to reduce GasNet’s forecast corporate overhead costs by $2 million per annum on the basis of assumed efficiencies associated with the APA Group’s acquisition of GasNet. The Draft Decision asserts that this is because the regulator must only approve those forecast costs which are best estimates arrived at on a reasonable basis in accordance with section 8.2(e) of the Code.

GasNet Response

As a general principle, GasNet believes that a service provider should not be required to pass on to users the benefits of efficiencies unless the costs of achieving those efficiencies are also recognised. GasNet submits that this is generally accepted in Australia economic regulation. The recovery of these costs is discussed in section 9.4 below.

No basis to incorporate the efficiencies

GasNet submits that its current Access Arrangement and the Code prevent the Commission from reducing GasNet’s Non Capital Costs to incorporate the possible efficiencies.

Clause 7.2(h) of the current Access Arrangement provides:

> *“In calculating the allowable revenues for operations and maintenance expenditure for the Third Access Arrangement Period, the Commission must:*
>
> *(i) comply with the requirements of the Code;*
>
> *(ii) take into account the actual operating costs in 2006, adjusted for the change in forecast operating costs between 2006 and*

2007 and, ***<u>to avoid doubt, not taking into account the efficiency gain (loss) made in 2007</u>****;*

(iii) *take into account forecast changes in workload, taxes, regulatory events, insurance premiums and other relevant costs between 2006 and each year of the Third Access Arrangement Period; and*

(iv) *take into account a percentage trend factor."* **(emphasis added)**

Clause 7.2(h) is a Fixed Principle which cannot be changed without GasNet's consent under section 8.47 of the Code. It clearly states that the Commission must not take into account any efficiency gain or loss made in 2007. This is because of the rolling carryover mechanism which the Commission required that GasNet incorporate into the current Access Arrangement.

The type of possible efficiencies which the Draft Decision considers would arise from the take over are not identified explicitly. If efficiencies do arise as a result of the change in ownership, these would primarily be as a result of economies of scale. Such possible efficiencies are the type of cost efficiencies that are contemplated by clause 7.2(h)(ii) of the Fixed Principle and the rolling carryover mechanism.

The possible efficiencies arising from the merger do not relate to changes in "workload" or "other relevant costs" and therefore cannot be taken into account under clause 7.2(h)(iii). Workload changes relate to changes in the nature or amount of work undertaken by GasNet in respect of the PTS, such as a result of changes in legislative requirements, an extension of the system or changes in the kind or scope of work undertaken by GasNet.

There is no change in GasNet's "workload" or the scope of activities performed by GasNet arising from the merger- it still provides the same services over the PTS to the same users and must perform the same activities and functions in order to so.

For the purpose of clause 7.2(h), the only difference arising from the merger is that some functions are being performed out of the APA Group rather than the GasNet Group. As a result, there may be possible efficiencies (which GasNet submits below are limited at this time). However, the only change would be to the cost of performing the functions, not the functions themselves.

Not only is the removal of the possible efficiencies expressly prohibited by clause 7.2(h)(ii), it is also inconsistent with the operation of the rolling carryover mechanism and intended affect on incentives. This mechanism is designed so that the benefits of efficiencies between GasNet and users are shared in the following manner:

- the efficiency gain (loss) is calculated using the actual reduction in costs;
- the Service Provider is allowed to retain the efficiency gain (loss) for a period of time (five years); and

- the gains (losses) are then passed onto users.

The rationale and benefits of this mechanism are discussed at length in the Commission's 2002 Final Decision. In short, the intention is to provide GasNet with an incentive to reduce costs by allowing it to keep the gains for a certain period of time.

GasNet accepts that to the extent that efficiencies are achieved as a result of the take over by the APA Group they should eventually be passed onto users. However, GasNet believes that this should be done in accordance with the incentive mechanism in the Access Arrangement. If possible efficiencies are passed through to users immediately, before they are even realised and quantified GasNet will have little incentive to take other measures to reduce costs or seek future efficiency gains, because it is likely that any cost reductions will be immediately passed on to users. If there is no benefit to the infrastructure owners in making gains, it is unlikely that the gains will not be made.

The achievement of efficiencies involves costs and risks, and an *ex post* benefit sharing mechanism is needed to take account of these costs and risks – if assumed benefits are transferred to users prior to realisation, businesses will have little incentive to invest in otherwise efficient activities, including merger activity.

The approach outlined in the Draft Decision is unreasonable. A reasonable approach would be to treat corporate efficiencies like other efficiencies and allow them to be realised and then at some point in the future return them to users via a benefit sharing mechanism. This approach is likely to provide appropriate incentives for benefits to be realised.

Further, the Draft Decision considers that it must incorporate the possible efficiencies as a result of section 8.2(e) which requires any forecasts used in setting the Reference Tariff to represent best estimates arrived at on a reasonable basis. However, the Draft Decision provides no justification as to how the estimate corporate costs after deduction of the $2 million is a best estimate, let alone an estimate arrived at on a reasonable basis. Moreover, GasNet considers that it is not appropriate to look at section 8.2(e) in isolation. It must be considered in the context of the remaining provisions in Chapter 8 of the Code, the Fixed Principle in clause 7.2(h)(ii) and the rolling carryover mechanism. When considered in the context of these other provisions, GasNet considers that the Draft Decision's reliance on section 8.2(e) to reject GasNet's forecast is completely unjustified.

Following the release of the Commission's Draft Decision on the proposed Access Arrangement for the Principal Transmission System, APA Group commissioned CRA International to provide a report commenting on the Draft Decision's treatment of corporate costs and synergies.

The report by CRA (attached) concludes that the proposed approach in the Draft Decision is flawed and is not consistent with well designed incentive regulation. CRA International recommends that:

> "*the most appropriate approach, and the approach that is consistent with the Gas Code is to provide incentives for merger-induced*

efficiencies comparable to other operating efficiencies. The ACCC should benchmark GasNet's corporate costs for the period 2008-12 starting from the 2006 (GasNet) actual value unless there is good ground to assume that this value is inefficient in the context of a stand-alone entity. The fact that GasNet's corporate overhead expenditure in 2006 was below the ACCC forecast for 2006 provides an a priori case that the value was efficient. If the ACCC is to be consistent in setting corporate overheads on a similar manner to other items of operating expenditure it should adopt the 2006 outturn as the starting point for determining a corporate overhead allowance for the period 2008-12, not a value $2 million lower"

Reduction of GasNet's proposed revenue by this amount will fail to meet section 2.24 of the Code in that it will not provide sufficient revenue for the safe and reliable operation of the pipeline and will also fail to comply with section 8.37 which provides for the recovery of all Non Capital Costs except those which would not be incurred by a prudent and efficient service provider. Finally, the decision would not satisfy, at least, the objectives specified in paragraphs (a), (b), (c) and (f) of section 8.1 of the Code.

The estimated efficiency gains

GasNet further submits that the Draft Decision has miscalculated the efficiencies. In particular:

(a) it has not included the costs incurred in achieving the possible efficiencies (this is addressed in section 9.5 below); and

(b) it has relied on outdated information.

The Draft Decision has vastly overstated the quantum of the efficiencies which may be achieved in AA3.

The Draft Decision is correct in basing its assessment on the APA Group's approach to allocating its corporate overheads on the basis of an asset's contribution to the APA Group's total revenue. However, the other information, which was provided to the Commission in 2005 and 2006, is now outdated.

Since that information was provided to the Commission:

- APA Group has acquired Murraylink, Directlink, the Allgas Gas Network, the Origin Energy Networks business and GasNet, and has invested in several gas processing and power station assets;

- the APA Group has purchased back the operation of pipelines which were previously operated by a third party;

- APA Group has grown from an organisation of approximately 30 employees in 2005 to an organisation of over 1000 employees in 2007, with an attendant increase in corporate operations and structure; and

- the ratio of revenues earned between various assets has changed.

These changes affect both the total quantum of the APA Group corporate costs and the allocation of these costs between various businesses. As a result, the information relied on in the Draft Decision is not a reasonable (and certainly not the best) estimate of GasNet corporate overheads.

While GasNet considers that the Fixed Principle is decisive on the issue of the treatment of operating costs, APA Group is willing to further discuss this issue with the Commission.

In addition to these matters, significant efficiencies have not been achieved to date and are not anticipated to be achieved. This is primarily because:

- **The unique nature of the Victorian market and operations**.

  Many of GasNet's corporate/overhead costs relate to issues specific to the Victorian market and assets. In particular, they related to the market carriage system, the MSO Rules and the interface with VENCorp and its practices. These "Victorian-specific" overheads cannot be reduced materially through corporate economies of scale.

- **Corporate economies of scale and scope were, and are, largely unavailable**.

  At the time of the APA acquisition of GasNet, APA was an organisation of approximately 30 employees with business systems and processes commensurate with an organisation of that size. All operating functions and some administrative functions were contracted out to third parties. In contrast GasNet undertook its operations "in-house" with approximately one hundred and ten employees with corporate systems relating to payroll, human resources, safety, accounting, IT etc commensurate with an organisation of greater size. These corporate systems were not able to be dismantled and subsumed into a pre-existing corporate system as APA's structure and systems were not such that the GasNet systems could simply be removed.

9.4 Corporate restructuring costs (DD sections and 3.2.5.2(ix) and 5.1.5.16)

GasNet's Position

In estimating possible efficiencies, the costs incurred in realising those efficiencies must be taken into account. The efficiencies in the Draft Decision are assumed to arise from the acquisition of GasNet by the APA Group and the subsequent integration of the two entities. However, the Draft Decision has failed to recognise the costs of achieving whatever efficiencies may in time be achieved. The costs of achieving these efficiencies include:

- APA Group's acquisition costs of $13.64 million. The proportion attributable to the regulated business is in the order of $10.00 million. These costs cover advisory, legal, banking, accounting, technical and market advice, and the costs of offer documentation and managing the offer.

- GasNet's defence costs, which were in excess of $10 million (see GasNet's Submission). The cost to the regulated business was $8.84 million. This amount includes payments to legal advisers, evaluation experts and strategic consultants for advice and a break fee.

- The cost of integrating business processes and systems, which are likely to be ongoing for several years and are likely to be substantial.

As submitted in GasNet's Submission, the costs incurred by GasNet are efficient and prudent costs which any Service Provider acting in accordance with good industry practice would incur. These costs are essentially a form of corporate governance costs, which any listed entity could be expected to incur from time to time.

The Corporations Act and the general law impose a number of obligations on directors, including the duty to act in the best interests of the corporation. In the context of the merger and acquisition activity, this requires that any takeover is tested to ensure that it represents fair value and is in the best interest of the corporation. If not, it also requires that a takeover be defended. As such these costs are legitimate costs.

Similarly, as any merger efficiencies will only be achievable as a result of the take-over, it is necessary to recognise APA Group's costs of the take-over.

These costs could be addressed in the Access Arrangement through one of a number of mechanisms including:

- capitalising them into the Capital Base; or

- offsetting them against expected future efficiencies.

Capitalising restructuring costs

GasNet submits that the costs incurred by APA and GasNet, in total $18.84 million during the takeover, should be recoverable as they are costs incurred in connection with the ownership and operation of the covered pipeline. There is substantial regulatory precedent for the approval of non-pipeline related capital expenditure.

For example, in its draft decision for the current review of gas distribution access arrangements, the ESC of Victoria has recently approved "capital overheads", which are the corporate overhead costs associated with scoping and delivering capital projects. These costs are not related to a specific new facility project and may actually relate to projects which do not proceed. Further, regulators have approved expenditure on IT systems being rolled into the capital base on numerous occasions. IT systems are used for maintenance and billing. Although they are integral to the provision of reference services, they are clearly not an extension or expansion to a pipeline but they are clearly capital assets. Other examples of non-pipeline capital costs which have been accepted by regulators as capital expenses incurred in the provision of services through covered pipelines are motor vehicles, buildings and furniture. It has also been recognised that equity raising costs or working capital may properly be treated as non-system capital assets. Similarly, acquisition and restructuring costs can be characterised as a capital asset, notwithstanding the fact that they are not physical assets and/or do not specifically relate to an expansion or extension of the capacity of a covered pipeline.

Offsetting costs against future efficiencies

Alternatively, the restructuring costs could be recovered by offsetting them against future efficiencies under the benefit sharing mechanism. For example, this could be achieved through an amendment to the benefit sharing mechanism under which:

- a separate notional account is established for the restructuring costs;
- in any year where there is an identified efficiency gain, that gain would be deducted from the balance in the restructure costs account; and
- efficiencies would then be passed onto users after the costs have been offset fully.

The asymmetric approach to the treatment of costs and benefits adopted by the Draft Decision is akin to the regulator recognising and appropriating the benefits of a new IT system, while not allowing the costs of investment in the system to be recovered. This approach is unreasonable and is inconsistent with the principles in Chapter 8 of the Code.

9.5 Benefit sharing allowance (DD section 5.1.5.18)

Draft Decision

The Draft Decision concluded that GasNet's calculations were generally in accordance with the current Access Arrangement provisions but indicated that GasNet had not escalated the value of the carryover amounts from June to December 2006 dollars when calculating its revenue requirement.

GasNet Response

GasNet has reviewed the treatment of carryover amounts arising from application of the benefit sharing mechanism. The Draft Decision is correct that the carryover amounts have been incorporated into the tariff model as June dollars rather than December dollars. However, GasNet notes that the treatment of the carryover amounts as input into the revenue model must be consistent with the treatment of all other inputs. Given the complexity of the revenue model, GasNet proposes that this be included in GasNet's dialogue with Commission in relation to the application of the revenue model (see section 12.1 below).

9.6 Self-insurance costs (DD section 5.1.5.23)

Draft Decision

The Draft Decision accepted the allowance of asymmetric risk proposed by GasNet but, relying on principles which have been established for the regulation of electricity transmission revenue, requires GasNet to put in place the following arrangements:

- a board resolution to self insure;
- confirmation that the service provider is in a position to undertake credibly self-insurance for those events;
- self-insurance details setting out the specific risk which the service provider has resolved to self-insure;
- a report from an appropriately qualified actuary or risk specialist verifying the calculation of risks and corresponding insurance premiums;
- ensuring that the costs of self-insurance are recorded as an operating expense in the income statement, and thereby deducted from the calculation of attributable profits;
- ensuring that a self-insurance reserve (funded by self-insurance premiums charged in the income statement) is established in the audited and published balance sheet; and
- ensuring that where a claim against self-insurance is made, that an appropriate deduction to the self-insurance reserve is recorded.

The Draft Decision considers that without such arrangement supporting the need for self-insurance, these costs would not be consistent with section 8.37 of the Code.

GasNet Response

GasNet does not agree with the Draft Decision that these administrative arrangements are required for the self-insurance costs to be consistent with section 8.37 of the Code.

Section 8.37 of the Code allows for the recovery of all Non Capital Costs except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently and in accordance with good industry practice.

In response to GasNet's appeal to the Tribunal in relation to the AA2 decision, these costs (including the quantum proposed by GasNet) were accepted as being prudent costs for the purposes of section 8.37 of the Code and did not require any further justification (which the Draft Decision is now requiring) in order to be satisfied that these costs met the requirements of section 8.37.

In relation to the principles established for regulation of electricity transmission, both the AER and the Commission acknowledge, in the AER Compendium and "Statement of principles for the regulation of transmission revenues" respectively, that:

- those documents are not made pursuant to the National Electricity Rules;

- the application of the relevant principles, including the administrative arrangements for self-insurance, to an individual electricity transmission service provider will depend on the individual circumstances; and

- they will depart from the principles if required or justified by the National Electricity Rules.

In relation to the amount GasNet is seeking of just under $190,000 per annum, which the Tribunal has already found to be prudent under the Code, GasNet submits that the administrative processes are not required or justified under section 8.37 of the Code.

The requirements which the Draft Decision intends to impose effectively seek to dictate board behaviour and accounting practices and in GasNet's view represent a level of interference in GasNet's business operations which is completely unwarranted.

9.7 Uplift liability allowance (DD section 5.1.5.22)

Draft Decision

In relation the allowance for uplift liability proposed by GasNet, the Draft Decision stated that the Commission intends to discuss with VENCorp and GasNet whether the $1 million uplift liability cap contained in the Service Envelope Agreement should be escalated for inflation.

GasNet Response

The Service Envelope Agreement was negotiated as a package and the liability regime reflects a trade-off in respect of various other aspects of the agreement. Accordingly, GasNet considers that it is inappropriate for the Draft Decision to simply focus on one aspect of that package and seek to enforce changes to that provision. The Commission's role is to consider GasNet's proposed Access Arrangement and not pro-actively procure changes to the liability cap regime through discussions with VENCorp.

Moreover, if a rigorous review were to be conducted into the appropriate liability cap, the outcome of that review could just as likely lead to a conclusion that a lower cap should apply. Given that such a review has not been conducted, GasNet considers that the Commission has no basis on which to arbitrarily increase the cap.

9.8 Equity raising costs (DD section 5.1.5.24)

Draft Decision

Despite approving an allowance of GasNet's equity raising costs for AA2, the Draft Decision has rejected an allowance for AA3. The Draft Decision, relying on a report from ACG, was of the view that if the Capital Base for a regulated entity has already been established it is not appropriate to include an allowance for the equity raising costs as they can be considered to be implicitly or explicitly incorporated into it.

GasNet Response

GasNet submits that, given the circumstances set out below, an allowance for equity raising costs should be included in GasNet's Non Capital Costs.

Although the ACG report does state that if a regulated asset base (RAB) has already been established, allowance for equity raising costs should not subsequently be allowed, this was on the basis that those costs had already been included in the RAB, either explicitly or implicitly. The ACG report also provides that:

- where the DORC methodology is used to set the RAB (as was the case for the PTS), an allowance for equity raising costs is appropriate; and

- where the RAB for a regulated entity was already established (presumably without inclusion of an allowance for equity raising costs), whether or not an allowance should subsequently be included in the RAB is a matter for the Commission to consider.

In its 2002 Final Decision the Commission acknowledged that there are two alternative views:

- the Initial Capital Base of a regulated entity incorporates all capital costs, such that no additional payment is required for equity raising; and

- the Initial Capital Base only measures the value of the physical assets, and therefore does not compensate the Service Provider for raising equity.

The 2002 Final Decision then went on to state:

> "*The Commission considers that both models have merit, although on balance it considers that the second model better reflects the process used to determine the capital base for GasNet. Consequently, the Commission maintains its position that it is reasonable to provide an allowance for equity raising costs, as they are costs required to be paid to an entity when it undertakes capital raising.* <u>*It does not consider that they have been incorporated in GasNet's capital base*</u>*.*" (emphasis added)

GasNet submits that an allowance for equity raising costs must be included in its Non Capital Costs on the basis that:

(a) as the Draft Decision itself stated, those costs have not been included in GasNet's Capital Base, and therefore the justification for not subsequently including those costs in the Capital Base (ie assuming that they have been incorporated) in the ACG report does not apply;

(b) the ACG report suggests that it might be appropriate to provide a subsequent allowance in some circumstances;

(c) GasNet should be able to recover all costs associated with the provision of the reference service and part of those cost include equity raising costs; and

(d) the Code prevents the Initial Capital Base being reopened and therefore the costs cannot now be incorporated into the RAB, but this should not prevent GasNet from recovering this as a Non Capital Cost; and

(e) inclusion of these costs in the Non Capital Costs is permitted under sections 8.36 and 8.37 of the Code.

Under the Code Non Capital Costs include "operating, maintenance and other costs incurred in the delivery of the Reference Services". GasNet has amortised the equity raising costs incurred over thirty years and therefore incurs the equity raising costs each year. Accordingly, these are "other costs" which are incurred in the delivery of the reference services. This is also supported by the fact that the Commission has previously approved the inclusion of equity raising costs in the Non Capital Costs.

The costs proposed by GasNet are prudent and efficient, as demonstrated by the fact that they are consistent with the amount previously approved by the Commission.

10 Pass through events

10.1 Asbestos risk (DD section 5.2.5.3)

Draft Decision

The Draft Decision supported the pass through events proposed by GasNet with the exception of the asbestos risk pass through event on the basis that the cost of future compensation claims should be borne by GasNet and not passed on to gas users.

GasNet Response

In response to the Draft Decision, GasNet commissioned a report from SAHA International to consider the Commission's position on this issue.

A copy of that report is at Attachment 3 this response.

In summary, SAHA's view is that:

(a) approval of a pass through event for asbestos risks will not affect GasNet's incentives to manage asbestos risk, primarily because it is already required to do so under the extensive *Occupational Health and Safety Regulations* 2007 and also because it faces significant damage its reputation as a result of claims;

(b) the costs should be passed onto end-users because these costs would be passed on in a competitive market and they are legitimate asymmetric risks that all gas businesses face; and

(c) a pass through mechanism for this risk is the most efficient means of addressing this.

In relation to regulatory obligations to managing asbestos risk, GasNet notes that it must also comply with the *Occupational Health and Safety Act*. The penalty for failure to comply with the relevant obligations in this Act is almost $1 million.

11 Volumes (DD section 5.4)

Draft Decision

The Draft Decision accepted GasNet's industrial, commercial and domestic forecasts. However, the Draft Decision has proposed a higher forecast for gas powered generation usage on the basis of a report prepared by the Commission's consultant ACIL Tasman.

GasNet Response

GasNet submitted its volume forecast in April 2007 based on the best available information at the time, which was the VENCorp Annual Planning Review forecast. Since then it has become clear that GPG volumes have increased due to the impact of the drought. The GPG forecast prepared by ACIL shows GPG volumes are likely to be higher than the original VENCorp forecast over the next regulatory period, due to the on-going impact of the drought.

GasNet accepts that GPG volumes are likely to be higher for the next two years as a result of the drought, and will amend the GPG volumes to the forecast provided by ACIL.

Since the Draft Decision was published, GasNet notes that VENCorp has published its latest Annual Planning Review.

The latest VENCorp Annual Planning Review shows some revisions to both the base demand (residential/commercial/industrial) and the GPG demand, as shown in the table.

Tale 11.1: Vencorp Annual Planning Review (PJs)

	2008	**2009**	**2010**	**2011**	**2012**
DD Base	212.4	212.8	214.0	21.50	217.4
DD GPG	16.4	6.4	4.4	6.2	8.1
Commission DD Total	**228.8**	**219.2**	**218.4**	**221.2**	**225.5**
VENCorp 2007 Base	208.6	208.4	209.9	213.5	215.6
VENCorp 2007 GPG	21.0	14.7	8.7	8.9	10.2
VENCorp 2007 Total	**229.7**	**223.1**	**218.6**	**222.4**	**225.8**

The change in the total volumes forecast over the full five years is 6.5 PJ (0.6%), which is immaterial.

However, the revised base demand is down by 15.6 PJ (1.5%) which is due to a large reduction in the starting year volume. This is not due to a change in the standard EDD, which is the same in the 2006 and 2007 forecasts.

GasNet proposes that VENCorp's revised base demand should be used to set the volume forecast, since it suggests a significant revision to the starting point for the volume forecast. However with respect to the GPG volumes forecast, GasNet understands that ACIL has a sophisticated electricity demand and production models, whereas VENCorp states in their 2007 Forecast Report (see section 4.5) that the GPG forecasts have not been prepared with an integrated gas and electricity model. Hence GasNet prefers the ACIL forecast to the VENCorp forecast prepared by NIEIR.

The proposed changes in the annual volume forecasts will flow through to the peak day and injection volume forecasts. GasNet will revise these forecasts based on the same methodology used in the Submission. That is, the revised peak days will be taken from the revised VENCorp and ACIL forecasts. The injection volumes will be kept the same at each injection point with the exception of Port Campbell injections which will be the balancing item between supply and demand.

12 Revenue

12.1 Revenue timing (DD section 5.5.3.1)

Draft Decision

The Draft Decision has accepted GasNet's proposal that capital expenditure should be recognised in the middle of each year. However the Draft Decision contends that GasNet has not properly taken account of the mismatch between when revenue is credited to the revenue model and when revenue is actually received. The Draft Decision has included its own calculation of this mismatch and has applied a revenue adjustment factor to the revenue model.

GasNet Response

Revenue model

The revenue model used in AA2 credited all revenues and costs at the end of each year. That is, the revenue was determined by equating the NPV of revenues to the NPV of costs on the assumption that all costs/revenues are incurred/received at the end of each year.

An implication of this model is that capital expenditure does not receive a return on investment between the time it is incurred and the end of the year. Since most of GasNet's capital expenditure is commissioned prior to winter, this assumption in the revenue model could cause a significant under-recovery if the capital expenditure was significant.

For AA3 GasNet has submitted a capital expenditure proposal of $334 million. Given such a high level of capital expenditure, the under-recovery from the incorrect recognition of capex timing is of the order of $15 million. GasNet therefore proposed a correction to the revenue model to recognise a return on capex from mid-year. GasNet also recognised the benefits of revenue and opex mismatch, but determined by modelling that this approximately balanced out the remaining loss from not recognising capital expenditure at the end of March when most projects are commissioned.

GasNet believes that the Draft Decision has misinterpreted the illustrative model provided by GasNet. GasNet's view is that the model does deal correctly with all aspects of revenue and cost timing.

Modification to capex proposal

As discussed above, the under-recovery from the incorrect recognition of capex timing can be as high as $15 million, but it will be less if the capital expenditure proposal is reduced in scope.

The Draft Decision has proposed significant reductions to GasNet's forecast capital expenditure proposal. In addition, the Brooklyn Lara pipeline capital expenditure has been treated as predominantly historical capex and will be rolled into the 2002 Capital Base. As a consequence, the balance between revenue timing and capex timing will need to be changed.

Therefore GasNet proposes to re-submit its revenue model and illustrative monthly model once the final capex plan is known, and enter a dialogue with the Commission to ensure that the model is being correctly interpreted and applied.

12.2 Authorised MDQ and AMDQ credit certificate revenues (DD section 5.5.3.2)

Draft Decision

The Draft Decision states that the provision of AMDQ/credit certificates is ancillary to the reference service on the basis that the reference service is provided under the terms and conditions set out in the SEA and the MSO Rules include provisions relating to the administration of AMDQ certificates. Accordingly, the Draft Decision requires GasNet to account for AMDQ revenue within the price control formula.

As the MSO Rules do not mandate the issuance of AMDQ/credit certificates and the Draft Decision's proposal removes any incentive for GasNet to issue authorised MDQ and AMDQ credit certificates, the Draft Decision states that the Commission intends to allow GasNet to recover any additional operating costs associated with issuing and administering the authorised MDQ and credit certificates.

GasNet position

GasNet's Access Arrangement regulates the terms on which it provides "reference services".

"Service" for the purposes of the "reference services" definition, means:

(a) a service provided by means of a Covered Pipeline (or when used in section 1 a service provided by means of a Pipeline) including (without limitation):

(i) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul); and

(ii) the right to interconnect with the Covered Pipeline, and

(b) services ancillary to the provision of such services,

but does not include the production, sale or purchasing of Natural Gas.

The position set out in the Draft Decision appears to be that, as the reference services comprises GasNet making the PTS available to VENCorp to operate under the MSO Rules, and the allocation of AMDQ rights is also dealt with under the MSO Rules, it follows that AMDQ rights are “ancillary” to the reference services within the meaning of the Code.

GasNet submits that this analysis misconstrues the definition of “ancillary” within the meaning of the Code. What is required to be shown is that, as a matter of fact, the allocation of AMDQ rights is ancillary to gas transportation and haulage services. Simply pointing to the fact that AMDQ rights and the provision of gas transportation services are both covered by the same regulatory instrument is not enough to satisfy that the former is ancillary to the latter. Simply put, regulation of two services by the same regulatory instrument cannot properly be a basis for concluding that one service is ancillary to the other.

GasNet’s reference service is currently defined as “making available the PTS on the same terms as those set out in the Service Envelope Agreement”.

The term “ancillary” is not defined in the Code. However, it is defined in the Macquarie Dictionary as, *“accessory; auxiliary (adj). an accessory, subsidiary helping thing or person (n)”*.

The concept of “ancillary” clearly contemplates that an ancillary service is one which supports or aids the provision of the main service. This is not the case in respect of GasNet’s Reference Service, which is clearly capable of being provided without the support of the AMDQ rights/certificates. Indeed, the fact that the MSO Rules give GasNet a discretion as to the allocation of AMDQ rights/certificates indicates that it is not ancillary to the provision of the Reference Service.

However, even if the Commission maintains the position set out in the Draft Decision that the provision of AMDQ rights/certificates is ancillary to the provision of GasNet’s reference service, GasNet’s view is that there are a number of other compelling reasons why the revenue from the provision of these rights/certificates should not be regulated.

First, the expected revenues from and demand for the provision of authorised MDQ rights/certificates is very difficult to predict. In this sense these rights are similar to the provision of backhaul, interruptible and park and loan services. The Commission has previously recognised that it is not always appropriate to regulate the tariffs for the provision of these services on the basis that to do so might act as a disincentive to the provision of the relevant services.

The Draft Decision also acknowledges that if revenues from the provision of AMDQ rights/certificates are regulated, this will act as a disincentive for GasNet to issue authorised MDQ and AMDQ certificates. The Draft Decision's solution to this issue is to allow GasNet to recover any additional operating costs associated with issuing and administering the authorised MDQ and AMDQ certificates. However, this clearly does not provide any incentive at all for GasNet to issue the MDQ and AMDQ certificates as GasNet would simply be cost neutral in these circumstances.

13 Reference tariffs

13.1 Cost allocation and reference tariff structures (DD section 6.1.4)

GasNet Proposal

GasNet is proposing a substantial revision to the cost allocation method used in the GasNet tariff model.

GasNet is proposing a simplified method whereby costs are allocated based only on the distance travelled between injection and offtake. However GasNet has retained the distinction between injection and withdrawal pipelines, so that a different unit cost rate is applied to the injection pipelines and the withdrawal pipelines. In comparison, the method used in AA2 allocates asset costs to each user according to the share of each asset segment used by that user's gas flow, and sums the costs over each segment according to the flow path between injection point and offtake.

GasNet is also proposing an amendment to the percentage of costs allocated to peak and annual flows. In AA2, the allocation was 60% to peak flows and 40% to annual volumes. However this was the average obtained by allocating 100% of injection pipeline costs to peak injections, and 45% of withdrawal pipeline costs to peak withdrawal flows.

GasNet is proposing to increase the allocation of costs to peak flows to 65%, and to use this same ratio on both injection and withdrawal pipelines.

Draft Decision The Draft Decision has rejected the simplified cost allocation method proposed by GasNet and the cost allocations to peak and annual flows.

The Draft Decision relies on the Commission's interpretation of sections 8.38 and 8.42 of the Code, under which costs should be attributed to each user "to the maximum extent that is commercially and technically feasible". It believes that this is supported by section 8.1(d) of the Code which states that tariffs should not distort investment decisions in pipelines. The Draft Decision notes that in the final decision for AA2, the Commission concluded that the method approved for AA2 offered the appropriate balance to any conflicting requirements of the Code.

The Draft Decision notes that other considerations such as simplicity, predictability, robustness, price stability and facilitation of retail competition are only indirectly relevant to the section 8 objectives. On this basis, the Draft Decision rejects the GasNet proposals because they dilute the cost reflectivity of the AA2 tariff methodology below what is technically and commercially achievable.

GasNet Position

GasNet notes that the preamble to chapter 8 of the Code expressly recognises that:

> *"the Reference Tariff Principles are designed to provide a high degree of flexibility so that the Reference Tariff Policy can be designed to meet the specific needs of each pipeline system. The overarching requirement is that when Reference Tariffs are determined and reviewed, they should be based on the efficient cost (or anticipated efficient cost) of providing Reference Services."*
>
> *"The Reference Tariff Principles set out broad principles for determining the portion of the Total Revenue that a Reference Tariff should be designed to recover from sales of the Reference Service, and the portion of revenue that should be recovered from each User of that Reference Service. These principles essentially require that the Charge paid by any User of a Reference Service be cost reflective, although substantial flexibility is provided."*

GasNet believes that the relevant issue here is the appropriate level of cost reflectivity in tariffs, when weighed against other considerations such as administrative simplicity, stability etc.

This is implicitly recognised by the Commission since the cost allocation method approved in AA2 reflects a trade-off between cost reflectivity and these other considerations. For example, it is technically and commercially feasible to approve a separate tariff for every one of the 120 offtakes on the GasNet system, but the Draft Decision has weighed this objective against the benefits of simplicity by approving an amalgamation of offtakes into geographic zones.

GasNet believes that its simplified cost allocation method is sufficiently cost reflective to satisfy the objectives of the Code, and also draws an appropriate balance between cost reflectivity and other considerations. Further it believes that the method used in AA2 goes beyond the requirements of economic efficiency (section 8.1(e) of the Code).

In order to assist in understanding the issues raised here, GasNet has described the proposed new cost allocation method using an illustrative example in Attachment 1. The method used in AA2 will be described as the "zone gate" model, and the simplified method proposed for AA3 will be described as the "volume-distance" model.

Code requirements

Sections 8.38 and 8.42 of the Code require that costs which are directly attributable to a user should be allocated to that user. However, it is not clear what makes a cost "attributable" to a user.

Under the zone-gate model, it is taken for granted that if a user uses 20% of the capacity of a pipeline segment, then they should be attributed 20% of the costs of that pipeline segment. This principle is applied to every pipeline segment on the PTS.

However, economic theory would suggest that one should attribute to a user only the long run marginal costs associated with that user. This may or may not be the same as the percentage share of capacity as assumed by the zone gate model. Since pipelines generally show economies of scale, the marginal costs attributable to an incremental user would tend to be less than the percentage share of capacity utilisation of the asset.

The requirements of sections 8.38 and 8.42 of the Code do not distinguish between a marginal cost allocation and a capacity usage allocation model, and do not indicate a preference for one model over the other. It is therefore necessary to also consider the objectives in sections 8.1 and 2.24 of the Code to determine which approach should be preferred, including requirements in the Code, such as section 8.1 and section 2.24(d) (economically efficient operation), section 2.24(e) (the public interest), and section 2.24(f) (the interests of Users).

Economic theory requires that allocated costs should be somewhere between the marginal cost and the stand-alone cost. Exactly where allocated costs should sit between these limits depends on a range of other considerations. However, particularly where economies of scale are present, there is nothing in economic theory to suggest that the correct allocation is based on a capacity sharing rule.

In GasNet's view, the best and most efficient method to allocate costs on a pipeline system cannot be reduced to a simple cost sharing model. There are many interrelated factors at work which would cause a cost sharing model to deviate from the best price signal. That is, the rigid application of the zone gate model is not necessarily consistent with economic theory or the objectives in the Code.

Some of the factors that lead to inconsistent price signals are:

- economies of scale in pipeline augmentation, which mean that the marginal cost price signal is significantly less than the average allocated tariff;
- under-utilisation of capacity (the zone gate model amplifies the unit rates in pipeline segments which are under-utilised);
- system development which deviates from the re-optimised configuration; and
- changes in the direction of flows (as on the northern pipeline and within the metro zone).

In light of these factors, it is appropriate to consider the range of other factors such as stability of the price signal over time, robustness to changing volumes and the timing of system augmentation, and encouraging development in regional areas etc.

Inconsistencies arising in the zone gate model

The following are two examples that demonstrate potential inconsistencies that arise from the strict application of the zone gate model. They demonstrate that the zone gate model can distort the correct price signals sent through the tariff.

(a) Optimized asset valuation

The valuation of the PTS in AA1 was based on an optimized system. For example, the Longford pipeline was valued as a single pipeline rather than as a partially duplicated pipeline. There was no pipeline link from Kyneton across to the Bendigo pipeline or Brooklyn to Ballan, but there was a large pipeline from Wollert to Ballan. In theory the tariff model should have allocated costs according to the optimized system, but for practical reasons the costs were allocated to the actual pipeline segments, but revalued to the optimized values.

As new assets are added, the enlarged system should in theory be re-optimized, and costs allocated according to the optimized system. In practice this is not done, and therefore the costs allocated under the zone gate model are only approximate representations of the correct price signal.

(b) Northern augmentation

Two options have been discussed to augment the northern zone, as discussed in section 4.3. The first option is to construct a long loop northwards from the Wollert compressor station. The second is to construct a short loop from Wollert, and to construct a new compressor station at Euroa. Both scenarios have similar costs.

Under the zone gate model, the South Hume zone (from Wollert to Euroa) would be allocated very different costs under the two options. In the Euroa compressor option, South Hume would not pay the cost of the compressor since it is downstream of the zone. However they would benefit from the lower tariffs in their zone created by the higher flows on the pipeline. Nevertheless, if the longer loop option is selected, they will pay a significantly higher share of the costs of the augmentation, since the loop is located within the South Hume zone.

Under the volume-distance model, the costs for users in the South Hume zone would increase marginally. However, the tariff increase would be the same whichever option is selected.

Efficient tariffs

The volume-distance model is identical to a zone-gate model if all pipelines are of equal diameter. In this situation, distance is the only factor that distinguishes tariffs. The models begin to diverge only when pipelines of different diameters exist on the system, and when compressors are added at various locations on the system. In the zone gate model, the downstream users, who are typically on the smaller diameter pipelines, will consequently be allocated significantly higher tariffs than upstream users (as shown in Attachment 5). However, this is not necessarily the best outcome when taking all relevant factors into consideration.

In reality, the best and most efficient tariff structure is likely to be somewhere between the volume-distance model and the zone gate model. GasNet believes a reasonable balance between the two methods is obtained by segregating the system into two groups, being the large capacity injection pipelines, and the smaller diameter withdrawal pipelines. Within each group the unit rates are equalised. However the unit rate on the injection pipelines is significantly lower than the unit rate on the withdrawal pipelines.

Under this proposal, tariffs are more stable over time, as refurbishments and augmentations of the withdrawal and injection pipelines do not lead to abrupt tariff changes in different zones.

Arbitrary price signals on injection pipelines

The current cost allocation model calculates the tariffs on each injection pipeline on a stand-alone basis. That is, the injection tariff on a particular pipeline is calculated from the specific pipeline assets, and the forecast flows on that pipeline. This means that the injection tariff faced by a user is strongly dependent on the forecast of injection volumes on that pipeline.

The gas market is highly competitive, and the gas volume injected at any point is a commercial decision for each Market Participant. GasNet has presented its best estimate of these injection volumes but, as GasNet stated in its Submission on volume forecasts, the injection volumes on each pipeline can only be conjectured. It is quite possible that Market Participants might enter new commercial arrangements which significantly change the mix of injections between injection points.

Therefore the injection tariff on each injection pipeline is largely an arbitrary number based on conjecture and assumption about the volumes to be injected into each pipeline. This is not an appropriate price signal to send to the market.

On the contrary, the proposed volume-distance model calculates the relativity between injection tariffs solely on the basis of the pipeline distances. The relativities are not affected by the assumed injection volumes on each pipeline. In GasNet's opinion this creates a more stable, valid and cost-based price signal over time, which is therefore more efficient.

The Commission should give consideration to the effect that uncertainty about future injection tariff, has on the commercial gas sourcing decisions of the Market Participants. Supply contracts generally extend over multiple regulatory periods, and it is not conducive to competition to allow such significant uncertainty in the setting of injection tariffs.

Brooklyn Lara pipeline

GasNet has proposed to allocate the Brooklyn Lara pipeline costs to all users on a postage stamp basis, since the pipeline provides system-wide benefits to all users.

However, GasNet proposes to revise this allocation to more closely reflect the distribution of benefits. The benefits of the Brooklyn Lara pipeline are obtained mainly by users of the Metro zone and downstream laterals, through the increase in linepack and capacity. The benefits to users on the injection pipelines are lower, and it is not appropriate to allocate the tariff to these zones. Therefore GasNet proposes that this cost not be allocated to the South West, LaTrobe, Tyers or Lurgi zones.

13.2 Murray Valley Pipeline (DD section 6.1.4.2(i))

GasNet proposal

GasNet proposes to recover the costs of the Murray Valley pipeline in the same way as all other withdrawal pipelines. In addition, GasNet proposes to bring the revenues generated by the Murray Valley pipeline within the price control mechanism applicable to other withdrawal pipelines.

Draft Decision The Draft Decision considers that the Murray Valley lateral should be segregated from the rest of the system and charged an incremental tariff, as applies in AA2. It also requires that the revenues returned from the incremental charge should not be included in the general price control mechanism.

The Draft Decision notes that the Murray Valley pipeline was rolled into the Capital Base on the basis that it passed the economic feasibility test. The Draft Decision interprets this to mean that all of the costs of the lateral must be recovered from the users of the lateral. Therefore the Draft Decision has determined that the Murray Valley pipeline lateral be charged as an incremental asset and that the revenues must be quarantined from the general price control model.

GasNet response

Section 8.16 simply sets out the basis on which New Facility Investment can be rolled into the Capital Base. In the Commission's 2002 Final Decision, it was accepted that this proposal met the economic feasibility test. As a result, the capital expenditure was rolled into the Capital Base. There is no basis now under the Code for the Commission to require that the tariffs for the Murray Valley Pipeline be determined in accordance with section 16(a)(ii)(A) of the Code.

Once an asset is rolled into the Capital Base, there is no reason to deviate from the standard cost allocation method that is applicable to all other assets in the Capital Base. If the cost allocation and tariff methodology that is applied to all other laterals is satisfactory, then it should be equally valid for the Murray Valley pipeline lateral. The Murray Valley pipeline should not be singled out for special treatment because it was constructed shortly after the AA1 period rather than shortly before it.

Second, even if the Murray Valley pipeline lateral remains subject to the economic feasibility test, the Draft Decision's application of the test is incorrect. The test requires that the tariff charged to users of the pipeline must cover the incremental costs. The incremental costs include the cost of the lateral, plus the incremental costs of transportation to the lateral, which in this case are the incremental costs from Longford and/or from Culcairn.

However, the incremental costs required to obtain transportation from Longford or from Culcairn should be deemed to be zero. This is because the system supplying the Murray Valley pipeline had adequate capacity at the time of construction to supply the forecast load growth on the pipeline, and hence no augmentation costs are required to meet that future load growth. Before the Murray Valley pipeline was constructed, the Victorian government put aside an amount of AMDQ to cover the future growth on the pipeline. That is, at the time of construction of the lateral, the system was capable of delivering to all existing users (including 17 TJ/day of exports at Culcairn), with spare capacity for the expected growth on the Murray Valley pipeline. Therefore the economic feasibility test requires that only the cost of the lateral must be recovered from the sum of the lateral tariff plus the tariff to Chiltern Valley. This would give a significantly lower tariff to users on the Murray Valley pipeline than would apply under the methodology adopted in the Draft Decision.

13.3 Postage Stamp withdrawal tariffs for Tariff-V Users (DD section 6.1.4.4(i))

GasNet Proposal

GasNet proposes to levy the Tariff-V tariffs on a postage stamp basis. That is, all Tariff-V users will pay the same tariff across the state. This will simplify the tariff, reduce administrative costs, and facilitate retail competition.

Draft Decision

The Draft Decision:

(a) does not accept a postage stamp tariff for Tariff-V users;

(b) states that the Commission is not convinced that administrative costs are a problem for retailers, and considers that there may be costs in revising IT systems if the tariff structure changes;

(c) accepts that users may not be able to respond to the price signals inherent in the AA2 tariff design, but considers that there are other reasons for tariff relativities, such as cost reflectivity; and

(d) states that whether retailers pass on the zonal tariffs or not, they should have the opportunity to do so and may do so in the future. Zonal tariffs also gives retailers the appropriate basis upon which to make their own investment decisions.

GasNet Response

Retailer support

Both AGL and TRUenergy strongly support the Tariff-V proposal. While Origin does not support the proposal in general, it appears to agree that the benefits to retail competition of the proposed change could outweigh the minor benefits to economic efficiency in the existing model. Origin is concerned that some users, especially in the Gippsland zone, may see a doubling of tariffs. However, this applies only to a very small number of customers, and in any case the absolute increase is only between $0.15/GJ to $0.20/GJ, which is insignificant compared to the total delivered gas price.

Administrative costs

It is hard to see how existing retailers would incur additional costs from this proposed reform. If the retailer already has the capacity to administer zonal tariffs, they can continue with exactly the same systems under this proposal. However, new entrants may be able to save on administrative costs which is a desirable outcome.

Retail competition

The Draft Decision has not given any weight to the facilitation of retail competition, which has been raised in AGL's submission. A large investment has been made in billing and reconciliation systems to facilitate retail competition, and it is a major policy objective of Australian governments. It is also a factor which the Commission must consider under section 2.24(e) of the Code.

Cost reflectivity

GasNet believes the Draft Decision has interpreted sections 8.38 and 8.42 too narrowly. Given the ambiguity in these provisions as discussed in section 13.1 above, the appropriate policy goals of the Code must also be considered. In particular, efficiency in the level and structure of tariffs (section 8.1(e)), must be balanced by other requirements such as the interests of users and prospective users (section 2.24(f)), and the public interest in having competition in markets (section 2.24(e)).

GasNet submits that the benefits of a simple tariff structure to retail competition (and resulting efficiency gains) outweigh the relatively small economic efficiency benefits of a complex zonal tariff structure for Tariff-V customers. This proposition has not been refuted in the Draft Decision.

In this regard it is worth noting that Distribution regulators have generally approved postage stamp tariffs for Tariff-V or residential consumers. This is because in their opinion the requirements of cost reflectivity are outweighed by issues of practicality and simplicity. It should be noted that distribution tariffs are significantly higher than GasNet's transmission tariffs, so if cost reflectivity were an over-riding issue, it would have greater weight in its application to the distribution networks.

13.4 Injection tariff structure (DD section 6.1.4.4(ii)

GasNet proposal

GasNet proposes to amend the injection tariffs so that the charge is applied on each day of the winter period June-September. This replaces the current tariff which levies charges on the 10-peak days at each injection point.

Draft Decision

The Draft Decision does not approve the revised charging method.

The Draft Decision sets out concerns that the move to a winter charge will weaken the peak pricing signal. The Draft Decision considers that users can and do respond to the peak signal, and any dilution of that signal will lead to more system constraints and avoidable investment.

The Draft Decision further considers that a winter charge will reduce incentives on users to minimise their peak usage, and will inappropriately advantage low load factor users, and vice versa.

The Draft Decision also notes that the proposal will reduce the complexity of the current charge, but believes this is not outweighed by the requirement for effective peak signalling.

GasNet Response

Retailer support

AGL and TRUenergy have given strong support to this proposal. They have documented in detail how the current method is complex, confusing and cumbersome. Origin has not made specific reference to this issue.

Unpredictability of charges

The Commission should give greater weight to the difficulties of a charge which is not known till the end of winter. A customer will not know their final charge until after the wash-up, which sends a confusing price signal.

Distortion of gas prices

Because the 10 peak days cannot be known in advance, the injectors cannot incorporate the injection charge into their bids into the gas market.

Therefore, it is possible for a retailer who buys from the market to avoid the injection charge entirely. This distorts retail competition.

Peak signalling

The Draft Decision notes concerns that the change to a winter tariff will weaken the signals to users to minimise their peak usage, which will distort investment decisions by users and by GasNet.

The issues are whether the peak signal is relevant to investment in the pipeline, and if so, whether the peak signal should be made stronger or weaker.

(a) Relevance of the pipeline peak signal

The gas market already sends a strong signal to users to avoid peak consumption. This is partly related to the higher costs of gas supply during the winter which is signalled through the gas price, but also through the uplift charges which signals congestion on the transmission pipelines. The very high uplift charges in 2007 clearly signalled the costs of peak consumption to users.

(b) Strength of the peak signal

GasNet agrees that there is a need for a peak signal in the injection tariff. However, it is not clear that it should be a strong peak signal levied on the peak day (as suggested by the EUCV submission).

First, economic theory suggests that prices should reflect the marginal costs. However where there are economies of scale, the marginal cost is less than the average cost. Therefore it is not appropriate to charge the whole cost to the peak; some of the cost must be smeared over a longer period.

Second, it is not correct to argue that the peak day demand alone "causes" the need for augmentation, and should therefore pay the full cost of capacity. This conclusion is only correct under limited conditions - where the pipeline is at full capacity, and where the injection volumes are not growing over time. First, if injection volumes are not at full capacity and are not expected to grow over time, then there is no economic justification for charging only on the peak. Second, if the pipeline is at full capacity, and the injection volumes are expected to grow over time, then the peak day alone is not the sole cause of future augmentations. The injection volumes over the whole winter will eventually grow to the point where they benefit from an augmentation. Therefore, these volumes also deserves an appropriate price signal of the cost of augmentation. For example, the cost/benefit analysis used to justify the Brooklyn Lara pipeline considered the NPV of curtailment costs over a period of many years into the future, and attributed value to the benefit of avoiding curtailment of demand in the future. As a result, the demand over the whole winter contributes to the need for an augmentation, and should receive a peak signal.

On this basis, GasNet believes that a winter injection charge does send an appropriate level of peak signal, in conjunction with the uplift and gas price signals sent by the gas market. The winter charge has the additional benefit of providing tariff certainty to retailers and users. It also allows the injection charge to be incorporated in the gas market price, thereby removing a distortion in the market.

13.5 Prudent discounts (DD section 6.1.4.5)

Draft Decision

The Draft Decision does not approve a prudent discount for Pakenham injections. The Draft Decision accepted GasNet's calculations for the Pakenham discount, however it notes that the changes in the tariff structure required by the Commission will change these results, and may not support the continuation of the prudent discount. Nevertheless, the Commission is open to consider a prudent discount at Pakenham based on tariffs calculated on the 10 peak days.

In relation to the LaTrobe zone, the Draft Decision acknowledged the concerns of some users about GasNet's proposal to remove the prudent discount, but considers that it cannot require GasNet to reinstate a prudent discount under the Code.

In relation to the prudent discount proposed by GasNet for Culcairn, the Draft Decision requested that GasNet provide further information to enable it to fully assess whether a prudent discount is justified. First, the Draft Decision requires evidence of effective competition at the Interconnect. Second, the Commission believes the prudent discount should be recalculated to be consistent with the tariff methodology approved by the Commission.

GasNet Response

Pakenham prudent discount

GasNet believes that any revision to the tariff structure is unlikely to change the need for a prudent discount on Pakenham injections. Prior to the final decision, GasNet will re-calculate the prudent discount on the relevant tariff structure if required.

LaTrobe zone discount

GasNet has considered the confidential submission provided by Australian Paper. Based on this new information, GasNet believes there may be a risk of economic bypass at the Maryvale paper plant.

GasNet also notes that Australian Paper has made significant investments in the belief that the prudent discount will continue, and that any uncertainty in tariffs going forward is likely to elicit a review of those investments.

Therefore GasNet proposes to create a new zone at Maryvale, which will include the lateral to the Maryvale plant. GasNet proposes that this zone should receive a prudent discount equal to the tariff which would have applied under the normal operation of the LaTrobe zone price path from 2004, escalated at CPI.

While a new zone increases the complexity of the tariff, it should be noted that the gas consumption in the new zone will exceed that in almost all other zones outside the metropolitan area, and therefore is warranted given that a prudent discount is required.

Culcairn export tariff

GasNet believes that the only viable tariff for Culcairn exports is close to the marginal cost because of the high level of competition it faces, and has set out further justification for this below.

GasNet's proposed discounted export tariff exceeds the marginal cost of supply and therefore it follows that any export flows must make a contribution to fixed costs, and therefore must benefit existing users and satisfy section 8.43(b).

In its Submission, GasNet provided a calculation of the marginal costs of supply on the basis of the Euroa compressor option for the northern zone augmentation . The export tariff proposed by GasNet of $0.50/GJ is greater than the marginal cost.

The marginal cost calculation is not affected by the cost allocation procedures in the tariff model given that the marginal cost calculation is based on actual costs. However, the calculation will be affected by changes in volumes along the pipeline, and by the option adopted for the northern zone augmentation. GasNet will review the marginal cost calculation when these issues are resolved.

The marginal cost calculation establishes the floor for a prudent discount, and the tariff model sets the maximum tariff. The discounted tariff should be determined by reference to the cost of supply from GasNet's competitors.

GasNet faces strong competition for supply to Sydney from Longford gas transported through the EGP for supply to Sydney. GasNet also faces some competition for supply to country NSW through gas swaps with Moomba gas. That is, Moomba supply to a Sydney customer could be redirected to the country region with a net saving in the MSP tariff, and the Sydney customer would be supplied from the EGP.

The MSP is also capable of delivering gas from Queensland (especially coal seam methane) through the MSP and the proposed new QSN Link and Moomba, although this is subject to availability and price. The QSN Link is expected to be completed at the end of 2008. GasNet understands that CSM from QLD is significantly cheaper than other gas supplies in the south eastern states which is likely to mean that transportation to NSW is commercially attractive.

Given that the strongest competition is from the EGP at this time, the discounted export tariff should be the EGP tariff less the (regulated) Culcairn to Sydney tariff and the published VENCorp charges. Based on GasNet's estimates it believes the competitive tariff is in the range of $0.42-$0.45/GJ. If Moomba was considered as a potential competitor the competitive tariff would be approximately $0.50/GJ.

Attachment 6 (confidential attachment) sets out the Culcairn export tariff comparisons.

14 Incentive mechanisms

14.1 Discretionary negative carry-over (DD section 7.1.5.2)

Draft Decision

The Draft Decision has rejected GasNet's proposal to include a provision in the Access Arrangement requiring the regulator to consider whether and to what extent negative carry over amounts should affect revenues in AA4.

The Draft Decision has also rejected GasNet's proposed amendment to the incentive mechanism to require the Commission to "use" the actual operating costs in 2011 as a basis for setting expenditure benchmarks for the AA4, rather than "take into account" these costs as per the current position.

GasNet Response

GasNet maintains that the benefit sharing mechanism should be amended to allow the regulator discretion to determine how any accrued negative carryover amount should be treated.

The primary concern detailed in the Draft Decision with this discretion is that the emphasis on the base year opex (ie 2006/2011) increases the prospect of gains by spending more in that year, and therefore reinforcing the need to apply negative carryover amounts to maintain the incentive to minimise costs each year.

However, GasNet submits that the regulator’s discretion to require the carry over of any losses is sufficient incentive to minimise costs in each year. GasNet could not defer expenditure until, or increase expenditure in, the base year because there would be a significant risk that the regulator would require carry over of losses. In these circumstances, the mere fact that the Commission has a discretion as to whether to require the carry over of losses is sufficient to influence GasNet’s behaviour.

15 Non-tariff element

15.1 Services policy (DD section 8.1)

Draft Decision

The Draft Decision requires GasNet to amend clause 3.2 of the proposed access arrangement to reflect the fact that GasNet will provide gas transportation services directly to users as well as making the PTS available to VENCorp as required by the Service Envelope Agreement.

GasNet Response

GasNet has now had an opportunity to consider the amendments proposed by the Government to the legislative regime and the MSO Rules in relation to the removal of the requirement for VENCorp to submit an access arrangement.

The main change arising from those amendments is that GasNet and not VENCorp will now enter into gas transportation agreements directly with Users. However, the legal and operational interfaces between GasNet and VENCorp will remain unchanged. That is, GasNet will make the tariffed transmission service available to VENCorp in accordance with the Service Envelope Agreement who operate the system in accordance with the MSO Rules. As GasNet is committed under the Service Envelope Agreement to provide the capacity of the PTS to VENCorp it has no capacity left to offer directly to users. The gas transportation agreements simply provide a mechanism for the recovery of GasNet’s tariffs and do not constitute an agreement by GasNet to transport gas for a user.

Accordingly, to say that GasNet is providing gas transmission services directly to Users is not correct.

GasNet does, however, propose a change to the services policy which is related to the change in the mechanism for tariffs and the changes which have been made to the regulatory arrangements in Victoria.

Under recent changes to the MSO Rules that will take effect from 1 January 2008, clause 2.1(e)(6) of the MSO Rules, which requires that a person be a party to an agreement requiring it to pay GasNet's transmission charges in order to register as a Market Participant, will be deleted.[15] This provision will then be replaced with a requirement that each Market Participant has an agreement providing for the payment of GasNet's transmission charges.

GasNet is concerned that a person may register as a Market Participant and be provided with gas transmission services before it has entered into an agreement to pay for those services or that the requirement for a Market Participant to enter into an agreement for the payment of GasNet's transmission charges may be removed from the MSO Rules. Therefore, GasNet seeks to amend its reference service to clarify that GasNet provides the capacity of the PTS to VENCorp in order for VENCorp to provide services to users who have entered into an agreement with GasNet providing for the payment of the Transmission Tariffs. In particular, GasNet proposes to amend the Tariffed Transmission Service as follows:

> "**Tariffed Transmission Service** means making available the PTS to VENCorp on the same terms as those set out in the Service Envelope Agreement and entering into agreements with users in accordance with section 5.3.1(aa) of the MSO Rules."

Other consequential changes to the services policy will be required, in particular to clause 3.1, to reflect the fact that VENCorp no longer directs Market Participants to pay the transmission tariffs directly to GasNet and that instead, these tariffs will be recovered directly by GasNet under the new agreements.

15.2 Terms and conditions (DD section 8.2)

Draft Decision

The Draft Decision requires GasNet to include a trigger event in the access arrangement to allow the Commission to assess and approve the revised gas transportation agreements.

GasNet Response

GasNet is happy to make a copy of the executed gas transportation agreements available to the Commission but does not consider it appropriate that the Commission approve the terms and conditions of those agreements.

As described above, these agreements will not constitute an agreement by GasNet to provide transmission services but simply provide a mechanism for GasNet to recover its tariffs. As such, they do not set out the terms and conditions on which the Reference Service will be supplied, these are instead set out in the Service Envelope Agreement and the MSO Rules.

[15] See Victorian Government Gazette, 6 December 2007 p2871.

Accordingly, GasNet does not consider that the Commission has the power under section 3.6 of the Code to approve the terms and conditions of the gas transportation agreements.

Further, GasNet does not believe that the Commission can require GasNet to submit the gas transportation agreements for approval under section 3.17(b)(ii) of the Code.

Section 3.17 relates to the revisions submission date. Under section 3.17(b)(ii) the Commission can only require that GasNet submit a revised new access arrangement. Although the Commission can require that revisions be submitted after a "specific major event", it cannot merely require that GasNet submits one part of the Access Arrangement for review.

Section 8.6 of the Draft Decision accepts GasNet's proposed five year Access Arrangement Period and further states:

> "*The ACCC considers that GasNet's proposed dates for submissions and commencement of the revised AA are consistent with the objectives of section 8.1 of the code and that a five year AA period is also consistent with there objectives.*"

Further, the Commission may only require an earlier revisions date if required having regard to the objectives in section 8.1, which relate to reference tariffs. GasNet queries how an early revisions date so that the Commission could review an agreement which has nothing to do with the amount of the reference tariffs could be required under the section 8.1 objectives.

It appears to GasNet that the Commission is attempting to impose a trigger mechanism on GasNet which is not provided for under the Code.

15.3 Extensions and expansions policy (DD section 8.5)

Draft Decision

The Draft Decision requires GasNet to amend its extension and expansion policy so that any expansion to increase withdrawals at Culcairn over and above the current capacity will be covered unless the regulator agrees, before the decision to construct the new facility is made, that it should not be covered. This is because of uncertainty about:

- the extent to which GasNet will have excessive market power at the Interconnect if/when an expansion is made; and
- how the unregulated capacity will coexist with regulated capacity within the market carriage system.

GasNet Response

First, GasNet submits that there is sufficient information available to the Commission to decide that GasNet does not have market power on the Interconnect, and there is nothing to suggest that this situation will change in the future.

GasNet faces competition for supply to Sydney and NSW country zones from the sources as already detailed in section 13.5.

It is inconsistent to suggest that the Interconnect export tariff must be regulated whilst EGP tariffs, and, to a large extent, the MSP tariffs, are unregulated. There is no basis to argue that GasNet has market power in relation to the Interconnect while the EGP does not have market power.

Indeed, the fact that GasNet is seeking a prudent discount for tariffs on the Interconnect as a result of the level of competition it faces suggests that it does not have market power in relation to the Interconnect. The analysis of competitive tariffs provided in (confidential) attachment 6 shows that the Interconnect must offer low, possibly marginal, tariffs if it is to compete with the EGP. In addition, the EGP can be expanded at low cost, whereas expansion of the Interconnect requires expensive looping. There is no case that can be made that the Interconnect has or can exploit market power.

Second, it should be understood that GasNet does not intend to operate outside of the market carriage system at Culcairn. If capacity is expanded on the Interconnect, then it is envisioned that VENCorp would continue to operate the system under the MSO Rules. If possible, GasNet would seek VENCorp's agreement to allocate more AMDQ to the Culcairn exports, but this would be within the MSO Rules. The only difference between this unregulated service and a regulated service would be the tariff treatment. Following an expansion, the export flows in excess of 17 TJ/day would attract a separate, unregulated tariff. This is no different in concept to a surcharge, excepting that this surcharge would not require approval.

GasNet will agree to include any expansions within the ambit of the Service Envelope Agreement, to ensure that VENCorp operates the entire system under a consistent set of rules.

16 List of Attachments

This submission is accompanied by a range of supporting material comprising the following attachments:

Attachment 1: Brooklyn to Lara Pipeline project - current status

Attachment 2: Brooklyn to Wollert loop project

Attachment 3: Brooklyn to Wollert loop project - route selection options

Attachment 4: SAHA letter about asbestos related risks

Attachment 5: Alternative cost allocation method

Attachment 6: Competitive export tariff (Confidential)

Attachment 7: CRA report