Draft Decision

GasNet Australia

access arrangement revisions

for the Principal Transmission System

14 August 2002

Preface

GasNet Australia (Operations) Pty Ltd (GasNet) lodged proposed revisions to its natural gas transmission access arrangements with the Australian Competition and Consumer Commission (the Commission) on 28 March 2002. The Victorian Energy Networks Corporation (VENCorp) also lodged proposed revisions to its access arrangement at that time. The Commission approved these access arrangements in 1998.

This Draft Decision sets out the Commission's draft assessment of GasNet's proposed revised access arrangement in accordance with the provisions of the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code). The Commission has released a separate draft decision with respect to VENCorp's proposed revised access arrangement.

Under the terms of the Code the Commission may only approve GasNet's proposed revised access arrangement if it is satisfied that it would comply with the provisions of the Code. The Code specifies that an access arrangement must contain certain elements and be consistent with a range of principles.

The Commission proposes not to approve GasNet's proposed revised access arrangement in its current form. This Draft Decision sets out the amendments (or nature of the amendments) which would have to be made to the revisions for the Commission to approve them. The Commission will consider submissions from interested parties and amended revisions from GasNet (if submitted) before issuing its final decision.

Written submissions are requested on this Draft Decision and should be received by the Commission no later than 13 September 2002.

Copies of GasNet's proposals and related information are available from the Commission's website at www.accc.gov.au (under 'Gas').

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Abbreviations and glossary

1998 Final Decision	ACCC, *Final Decision: access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System; access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System; and access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System*, 6 October 1998
access arrangement	an arrangement for third party access to a pipeline provided by a service provider and approved by the relevant regulator in accordance with the Code
access arrangement information	information provided by a service provider to the relevant regulator pursuant to section 2 of the Code
access arrangement period	the period from when an access arrangement or revisions to an access arrangement takes effect (by virtue of a decision pursuant to section 2) until the next revisions commencement date
ACG	The Allen Consulting Group
AGSM	Australian Graduate School of Management
AMDQ	authorised maximum daily quantity
APT	Australian Pipelines Trust
ATT	average transmission tariff
CAPM	capital asset pricing model
Code	National Third Party Access Code for Natural Gas Pipeline Systems
Commission	Australian Competition and Consumer Commission
covered pipeline	a pipeline to which the provisions of the Code apply
CPI	Consumer Price Index
DEI	Duke Energy International
DNRE	Department of Natural Resources and Environment, Victoria

DRP	*Draft Statement of Principles for the Regulation of Transmission Revenues*
EAPL	East Australian Pipeline Ltd
EGP	Eastern Gas Pipeline
ESC	Essential Services Commission
EUAA	Energy Users Association of Australia
FATT	forecast average transmission tariff
G&A	general and administrative
GasNet	GasNet Australia (Operations) Pty Limited
GHD	Gutteridge, Haskins and Davey Pty Limited
GIA	Gas Industry Act
GJ	gigajoule (one thousand million joules)
GPAL	Gas Pipelines Access Law
ICB	initial capital base
IRR	internal rate of return
KPI	key performance indicators
LNG	Liquefied Natural Gas
market carriage	a capacity management system where the service provider does not normally require users to commit to a contract. Instead charges are based on actual usage
MATT	maximum average transmission tariff
MDQ	maximum daily quantity
MSOR	Market and System Operations Rules
MSP	Moomba to Sydney Pipeline
NECG	Network Economics Consulting Group
NGPAC	National Gas Pipelines Advisory Committee
NPV	net present value
O&M	operating and maintenance

ORC	optimised replacement cost
ORG	Office of the Regulator-General, Victoria
PJ	petajoule (one thousand terajoules)
prospective user	a person who seeks or who is reasonably likely to seek to enter into a contract for a service (including a user who seeks or may seek to enter into a contract for an additional service)
PTS	Principal Transmission System
RAB	regulatory asset base
reference service	a service which is specified in an access arrangement and in respect of which a reference tariff has been determined
reference tariff	a tariff specified in an access arrangement as corresponding to a reference service.
reference tariff policy	a policy describing the principles that are to be used to determine a reference tariff
service envelope agreement (SEA)	an agreement between VENCorp and GasNet whereby GasNet makes the Gas Transmission System available to VENCorp
service provider	a person who is the owner or operator of the whole or any part of the pipeline or proposed pipeline
Tariff Order	Victorian Gas Industry Tariff Order
TJ	terajoule (one thousand gigajoules)
TPA	Transmission Pipelines Australia Pty Ltd
VENCorp	Victorian Energy Networks Corporation
WACC	weighted average cost of capital
WTS	Western Transmission System
WUGS	Western Underground Storage

Executive summary

The Commission is currently conducting its first scheduled review of the GasNet Australia (Operations) Pty Ltd (GasNet) and the Victorian Energy Networks Corporation (VENCorp) access arrangements which it approved in 1998. GasNet owns the Victorian Principal Transmission System (PTS) and Western Transmission System (WTS) while VENCorp is the independent system operator of the PTS.

The two service providers submitted proposed revised access arrangements and access arrangement information to the Commission on 28 March 2002. While the revisions are subject to two separate regulatory processes (see also the VENCorp Draft Decision) this document also refers in part to the proposed VENCorp revisions where applicable.

GasNet has proposed substantial changes to its access arrangements whereas VENCorp's proposal is largely to maintain the status quo. GasNet proposed significant real increases in tariffs and revenues while VENCorp proposed decreases.

The Commission proposes to accept a range of major changes to the arrangements it approved in 1998. These include merging GasNet's two access arrangements, including the Southwest Pipeline in the asset base, the introduction of pass through mechanisms and prudent discounts, changes to the tariff control formula so that loss of revenue due to changes in product mix can be recouped and the removal of the automatic requirement for small pipeline extensions to be regulated. The Commission proposes to accept GasNet's aggregate demand forecasts and that it recoup approximately $10.3 million (2002 dollars) of unrecovered revenue from the first access arrangement period. It also proposes that GasNet be able to retain approximately $16 million of tax allowances included in GasNet's target revenue for the first access arrangement period under the pre-tax approach adopted for that time. However, it does not consider that a number of other proposals are consistent with the principles and objectives of the Code.

Draft Decision

After considering GasNet's proposals and submissions by interested parties, the Commission has decided, pursuant to section 2.35(b) of the Code, to issue a draft decision that it proposes not to approve the proposed revisions to GasNet's access arrangements in their current form. This Draft Decision sets out the amendments (or nature of the amendments) which would have to be made to the revisions for the Commission to approve them. Key issues are summarised below.

Key issues

Rolling forward the capital base

The Commission carefully considered the merits of GasNet's proposal to reopen its regulatory asset base and to adjust it upwards by $41.2 million (to a January 1998 value of $399.2 million). The Commission considers that such a revaluation is unwarranted and would not be consistent with regulatory policy objectives. The Commission is satisfied that it correctly interpreted the requirements of the (Victorian) Code when it approved GasNet's predecessor's proposed valuation of the initial capital base in 1998. The valuation approved in 1998 ($358.0 million) was consistent with that proposed by the Victorian Government as owner at the time of the PTS and WTS. The subsequent purchases of these assets were made in the knowledge that the regulatory asset base had already been set.

In addition, the Code does not give the Commission the discretion to make such an adjustment once the initial capital base has been established. Accordingly, the Commission proposes not to accept the revaluations proposed by GasNet to the initial capital base.

The roll forward of this capital base to the start of the next access arrangement period involves the addition of the Southwest Pipeline, the Interconnect Assets, the Western Transmission System, the Murray Valley Pipeline and some smaller investments, deduction of depreciation and redundant assets and inflation adjustments to the capital value each year. The Commission proposes that the appropriate value of the regulatory asset base at 31 December 2002 will be approximately $493.2 million.

Benchmark rate of return

GasNet proposed a benchmark return on equity of 14.19 per cent. The Commission has generally accepted the parameter values proposed by GasNet as input to the benchmark return calculation under the capital asset pricing model (CAPM) methodology. However, it considers the proposed equity beta exaggerates the risks faced by a regulated natural gas transmission service provider. In addition, it considers that the most appropriate bond rate term for calculating the risk free rate is one that corresponds to the regulatory period. The Commission considers that a benchmark return on equity of 11.9 per cent is appropriate for GasNet.

Importantly, incentives proposed for the second access arrangement period would allow GasNet the opportunity to exceed this benchmark return.

Revenue approach

GasNet proposed to use a pre-tax approach to determine target revenue and to retain the benefits of tax pre-paid by users during the first access arrangement period. It also proposed that the benefits of accelerated depreciation would accrue to GasNet rather than flow through to lower charges. The Commission proposes to adopt a post-tax approach that treats estimates of tax actually paid as a cost component in the cash flows. However, it proposes that GasNet be able to retain the benefits of tax pre-paid by users during the first access arrangement period. This is a substantial benefit to GasNet. The Commission estimates that GasNet would accrue an additional revenue of approximately $16 million if it confirms this proposal in its final decision.

Tariff path

GasNet proposed a real increase in weighted average tariffs from the 2002 tariffs to the discounted weighted average tariff to apply over 2003 to 2007 of 11 per cent. Revenue was proposed to increase by approximately 38 per cent between 2002 and 2003 with tariffs also increasing sharply between 2002 and 2003 then following a CPI-4.5 per cent price path. Following the reduced revenue requirement that is proposed by the

Commission in this Draft Decision, a different tariff path is required. The Commission expects GasNet to take into consideration the initial change in tariff between 2002 and 2003 and the price path within the period as well as the end of period tariff movement. It anticipates that GasNet will produce a tariff path that limits the price shocks for users and produces a real decline in tariffs over time.

Costs allocation and tariff structure

For the first access arrangement period, GasNet allocated capital costs to pipeline and compressor assets groups on the basis of their Optimised Replacement Cost (ORC) and then to users within the asset groups on the basis of peak usage. This constituted 65 per cent of costs. Direct operating costs were allocated to withdrawal assets on the basis of distance from the gas source and the total volume withdrawn. Indirect costs were allocated on a postage stamp basis (an amount per GJ, irrespective of the amount of the system used). A peak injection and a peak withdrawal tariff was charged (recovering 65 per cent of revenue requirement) and an anytime tariff was charged on total volumes.

GasNet's proposed cost allocation is broadly similar with the following changes: direct operating costs are allocated to injection as well as withdrawal pipelines; and the allocation of 60 per cent (rather than 65 per cent) of costs on the basis of peak usage. As well, there are new costs proposed to be allocated on a postage stamp basis: under-recovered K factor adjustment, GasNet's share of efficiency gains, and capital raising costs.

With regard to tariffs, GasNet proposes to remove the peak withdrawal tariff, leaving the peak injection tariff which will recover 27 per cent of revenue requirement and the anytime withdrawal tariff which will recover 73 per cent of revenue requirement. As well, a new cross system withdrawal tariff is proposed (which is likely to affect a very small number of customers).

The Commission considers the appropriate basis for allocating the unrecovered K factor amount to be on a uniform percentage of tariff; the efficiency gain on the same basis as all other operating costs; and capital raising costs on the same basis as capital costs. The Commission considers that the allocation of all other costs to be on an appropriate basis.

The major issue raised by the change to cost allocation and tariff structure is that of appropriate price signals. Some interested parties call for the removal of all peak pricing and others call for the retention of the current structure. Peak signals are appropriate if the relevant asset is constrained or likely to be constrained, and if users are likely to respond to such signals. The evidence for whether, and which, pipelines are close to constraint is mixed, with some suggestion that some withdrawal pipelines are closer to constraint than the injection pipelines. There is also some evidence that users generally do not respond to peak signals. Consequently, the Commission is not convinced that the evidence is compelling for either of the alternatives proposed by interested parties in their submissions. Therefore the Commission proposes, at this stage, not to oppose the tariff structure and cost allocation proposed by GasNet, but to request more evidence on the issue from interested parties.

Merger of the Western Transmission System access arrangement

The Commission proposes to accept GasNet's proposal that the revised access arrangement will be in respect of both the PTS and the WTS.

Southwest Pipeline

GasNet proposed to include the full cost of the Southwest Pipeline ($85.0 million) in its capital base alternatively through:

- the economic feasibility test;
- the system-wide benefits test;
- a combination of the economic feasibility test and the system-wide benefits test; and
- treating it as a new pipeline with a separate access arrangement.

The Code's economic feasibility test would be satisfied if incremental revenue expected to be achieved by the PTS as a result of the operation of the Southwest Pipeline at least covered the costs of that pipeline.

In applying the Code's economic feasibility test the Commission must be satisfied that the Southwest Pipeline would be viable without funding or cross-subsidisation from the use of other parts of the PTS. This assessment relies crucially on the willingness of users to pay the stand-alone Southwest Pipeline tariff and the likely level of demand at that tariff (as the associated costs are known with considerable certainty). The Commission is not persuaded that GasNet's demand forecasts for the Southwest Pipeline are likely to be achieved at the proposed tariff. Accordingly, it has concluded that this investment would be unlikely to satisfy the Code's economic feasibility test.

Consequently, the Commission has also considered GasNet's contention that sufficient system-wide benefits would be generated by the Southwest Pipeline to justify a higher tariff for all users. However, it has confirmed the view expressed in its June 2001 Southwest Pipeline Final Decision that available evidence suggests that this test would not be satisfied.

The Commission concluded at that time that provisions of GasNet's access arrangement place restrictions on this assessment as they do not allow an investment to be partly included in the capital base under both the economic feasibility test and the system wide benefits tests. The Commission proposes to accept revisions to GasNet's extensions and expansions policy that would have the effect of more closely aligning GasNet's access arrangement with the provisions of the Code in this regard. In addition, it notes the additional discretion provided by the Code in this regard when rolling forward the capital base at the start of a new access arrangement period.

The Commission proposes to accept inclusion of GasNet's investment in the Southwest Pipeline in the capital base. This will be partly under the Code's economic feasibility test and partly under the system-wide benefits test.

Services policy

The Commission is of the view that GasNet's access arrangement must contain a services policy which includes appropriate reference services and is consistent with VENCorp's access arrangement.

Terms and conditions

The Commission is of the view that GasNet's access arrangement must contain a appropriate terms and conditions on which it will provide the reference services.

Pass through mechanism and zonal changes

GasNet has proposed a 'pass through' mechanism (for tax increases, increased regulatory requirements and increased insurance premiums) and a mechanism allowing it to change zones. These mechanisms would not require assessment under the Code's standard review process. The Commission acknowledges that the proposed mechanisms are likely to be cost-effective and agrees to them in principle. However, it proposes changes to the proposals to allow sufficient evaluation time for due process and so that decreased costs can also be passed through.

Benefit sharing mechanism

GasNet proposed no benefit sharing carryover for efficiencies achieved in the first period for capital expenditure. For operations and maintenance expenditure, GasNet proposed a benefit sharing mechanism which defined operational efficiencies achieved by GasNet in the first access arrangement period in terms of the difference between forecast costs for 2002 and forecast costs for the second access arrangement period. The efficiency gain would be quantified in perpetuity and a proportion (20 per cent) would be retained by GasNet and included in its revenue allowance for the second access arrangement period.

The Commission concurs with the proposal put forward by GasNet for first period capital expenditure. With regard to operations and maintenance expenditure, the Commission considers that a benefit sharing mechanism should take into account sustainable efficiencies that are actually achieved. GasNet achieved considerable reductions in its operations and maintenance costs during the initial access arrangement period and has enjoyed the benefits of these savings. However, these efficiencies have not been sustained. Under the Commission's preferred efficiency approach, this performance would result in a negative efficiency carryover for GasNet into the second access arrangement period. However, GasNet was not aware of this particular benefit sharing mechanism prior to or during the first access arrangement period. On balance, the Commission proposes not to require any revenue reduction to operations and maintenance expenditure as a consequence of the benefit sharing mechanism in the second access arrangement period.

For second period gains (losses) achieved, the Commission considers that the approach proposed by GasNet for capital expenditure (of no carryover of benefits/losses achieved) is appropriate. The Commission, however, does not agree with GasNet's proposal for the treatment of operations and maintenance expenditure efficiencies in the second period. Instead the Commission proposes the adoption of the rolling carryover mechanism for unanticipated gains (losses) realised in the second and subsequent periods. Under this approach there is a continuous incentive for efficiency gains throughout the regulatory period as efficiencies are retained by GasNet for five additional years regardless of when they are implemented. The mechanism proposed by the Commission treats efficiency gains and losses equally, makes no distinction between controllable and uncontrollable gains (losses) and adjusts for additional costs associated with new capital expenditure. It is also proposed that operations and maintenance expenditure forecasts in the third period be based on actuals achieved in the second period, adjusted through relevant step and trend factors.

Prudent discounts

The Commission has assessed GasNet's proposal to introduce prudent discounts for the LaTrobe, Wodonga, Western zones and Dandenong Bypass. It considers that GasNet's proposals are reasonable.

Forecast capital expenditure

GasNet has forecast capital expenditure of $97 million over the second access arrangement period. The Commission considers that the proposed investments in the majority of projects are reasonably likely to pass the requirements in section 8.16 of the Code when those investments are forecast to occur.

The Commission proposes that a total of $57 million forecast new facilities investment be included in the determination of the reference tariffs for the second access arrangement period.

The balance of the forecast expenditure can be included in the capital base if it is undertaken and the facility is covered by GasNet's access arrangement (subject to the tests in section 8.16 of the Code).

The Commission proposes not to include the forecast expenditure relating to the Brooklyn loop project as it is uncertain as to whether this project will proceed within the forthcoming access arrangement period. While the Commission accepts the costs associated with the first stage of the Lurgi rehabilitation project, it does not accept the proposed stage two costs due to their considerable uncertainty. In addition, the Commission proposes that $7.5 million associated with possible service lines be excluded as there is no information available to assess the proposed investments against Code criteria. It is also uncertain whether these service lines would be covered by GasNet's access arrangement in the event that they are built.

Forecast operations and maintenance expenditure

The Commission has assessed GasNet's forecast expenditure on operations and maintenance and does not accept GasNet's proposal to include litigation costs in allowable revenues. The Commission accepts GasNet's proposal to recover prudent regulatory review costs incurred in 2001-2002 in 2003 revenues, and requests final estimates from GasNet as soon as possible. The majority of the annual allowance for asymmetric costs has not been accepted by the Commission as many items included in the allowance were not considered appropriate either in quantum or in the impact on users and GasNet.

Forecast demand

The Commission has considered the (comparatively small) differences between the aggregate gas demand projections underpinning the proposed GasNet and VENCorp tariffs. It considers that that these forecasts should be consistent across the two access arrangements. It notes that the VENCorp forecasts have been determined through a transparent process involving public consultation and that they form a sound basis for deriving tariffs for the second access arrangement period. The Commission considers that adjustments incorporated by GasNet to further accommodate a projected warming trend may, on balance, be reasonable. It proposes to accept GasNet's aggregate forecasts for the purposes of both access arrangements but will consider these further before making its final decisions. In view of developments such as those of the Yolla fields, it proposes some changes to GasNet's projected flow estimates.

Capital redundancy policy

The current policy allows an adjustment to be made to GasNet's capital base for partially or wholly redundant assets at the time of a scheduled review of the access arrangement. GasNet considers that the provision regarding partially redundant assets creates uncertainty and should be removed. While the Commission acknowledges that some uncertainty may exist, it is not persuaded that it should be shifted so that it falls on users. Risks should be borne by those who can best manage them. The Commission also notes that the existence of a capital redundancy policy puts pressure on a service provider to ensure that its investments are appropriate. The Commission proposes that GasNet retain its current redundant capital policy.

Asset lives

The Commission acknowledges concerns expressed by interested parties about GasNet's proposals to change the effective end of life estimate of the Longford to Pakenham pipeline from 2030 to 2023 and to adopt an effective life for the Southwest Pipeline extending until 2052. It is not satisfied that a reduction in the expected life of the Longford to Pakenham pipeline is warranted. However, it proposes to accept GasNet's proposed life for the Southwest Pipeline.

Part A – Introduction

1. Introduction

1.1 Access arrangement revisions

GasNet Australia (Operations) Pty Ltd (GasNet) is currently subject to two separate natural gas transmission access arrangements, which were approved by the Commission in 1998, for the Principal Transmission System (PTS) and the Western Transmission System (WTS).

In accordance with the provisions of its access arrangements, GasNet submitted a proposed revised access arrangement and revised access arrangement information to the Commission on 28 March 2002. GasNet states that its single revised access arrangement would apply to the GasNet System (GNS) which would include both the PTS and the WTS.[1]

Under the market carriage capacity management system operating on the PTS, users pay tariffs to both the system owner, GasNet, and the independent system operator, Victorian Energy Networks Corporation (VENCorp). Approximately 85 per cent of the combined tariff is currently paid to GasNet. VENCorp has also submitted a proposed revised access arrangement to the Commission which is the subject of a separate approval process.

An access arrangement describes the terms and conditions on which a service provider will make access available to third parties. The initial access arrangement period ends on 31 December 2002. The second access arrangement period is scheduled to commence on 1 January 2003 and is proposed to end on 31 December 2007. However, service providers have the discretion to submit revisions earlier than at a scheduled review.

Under the Code, the Commission is required to:

- inform interested parties that it has received the proposed revisions to the access arrangements and the associated access arrangement information (parties were notified by letter on 5 April 2002);
- publish a notice in a national daily paper which at least; describes the covered pipelines to which the access arrangements relate; states how copies of the documents may be obtained; and requests submissions by a date specified in the notice (the notice was inserted in the *Australian Financial Review* and the *Age* on 8 April 2002);
- after considering submissions received, issue a draft decision which either proposes to approve the revisions or proposes not to approve the revisions and states the amendments (or nature of the amendments) which would have to be made to the revisions in order for the Commission to approve them;

[1] In contrast, VENCorp refers to the combined system as the PTS. For consistency, the convention has been adopted in this Draft Decision of referring to the system as the PTS.

- after considering additional submissions, issue a final decision that either approves or does not approve the revisions (or amended revisions) and states the amendments (or nature of the amendments) which have to be made to the revisions (or amended revisions) in order for the Commission to approve them; and

- if the amendments are satisfactorily incorporated in amended revisions, issue a final approval. If the Commission is satisfied that the amended revisions either substantially incorporate the amendments specified or otherwise address to its satisfaction the matters which led it specifying the amendments in its final decision, either approve or not approve the amended revisions. In any other case, the Commission must draft and approve its own revisions.

1.2 Criteria for assessing revisions to access arrangements

The Commission may approve revisions to an access arrangement only if it is satisfied that the access arrangement as revised would contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Code, which are summarised below. Revisions to an access arrangement cannot be opposed solely on the basis that the access arrangement as revised would not address a matter that section 3 of the Code does not require it to address. Subject to this, the Commission has a broad discretion in accepting or opposing revisions to an access arrangement.

An access arrangement, or a revised access arrangement, must include the following elements:

- a policy on the service or services to be offered which includes a description of the service(s) to be offered;
- a reference tariff policy and one or more reference tariffs. A reference tariff operates as a benchmark tariff for a particular service and provides users with a right of access to the specific service at the specific tariff. Tariffs must be determined according to the reference tariff principles in section 8 of the Code;
- terms and conditions on which the service provider will supply each reference service;
- a statement of whether a contract carriage or market carriage capacity management policy is applicable;
- a trading policy that enables a user to trade its right to obtain a service (on a contract carriage pipeline) to another person;
- a queuing policy to determine users' priorities in obtaining access to spare and developable capacity on a pipeline;
- an extensions and expansions policy to determine the treatment of an extension or expansion of a pipeline under the Code;
- a date by which revisions to the arrangement must be submitted; and
- a date by which the revisions are intended to commence.

The Code (section 10.2) provides that, where there is more than one service provider in connection with a covered pipeline, with one the owner and the other the operator, responsibility for complying with the obligations imposed by the Code is allocated among them by their access arrangement(s) and each service provider is responsible for complying with the responsibilities allocated to it.

In considering whether a revised access arrangement complies with the Code, the Commission must take into account the provisions of the access arrangement as it currently stands and, pursuant to section 2.24 of the Code, the following factors:

- the legitimate business interests and investment of the service provider;
- firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline;
- the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline;
- the economically efficient operation of the covered pipeline;
- the public interest, including the public interest in having competition in markets (whether or not in Australia);
- the interests of users and prospective users; and
- any other matters that the Commission considers are relevant.

Appendix C to this Draft Decision sets out the access arrangement information that a service provider must disclose to interested parties (Attachment A to the Code).

1.3 Public consultation

Interested parties are invited to make written submissions to the Commission on its Draft Decision by Friday 13 September 2002. If requested and time permits, a public forum may be held on the issues raised in this decision and the Commission's proposed approach. After considering further submissions, the Commission will issue its Final Decision.

Submissions are made available from the Commission's website (www.accc.gov.au). They are also placed on the public registers held by the Commission and the Code Registrar. Submissions should be supplied in electronic format compatible with Microsoft Word to the review e-mail address below. In addition, one original signed document should be mailed to the postal address below. Any information considered to be of a confidential nature should be clearly marked as such, and the reasons for seeking confidentiality should be provided. Under the terms of the Code, the Commission must not disclose such information unless it is of the opinion that disclosure would not be unduly harmful to the legitimate business interests of the service provider, a user or prospective user.

The Commission's e-mail address for this review is victoriangasreview@accc.gov.au. Hard copies of submissions should be forwarded to:

Ms Kanwaljit Kaur
General Manager
Regulatory Affairs – Gas
Australian Competition and Consumer Commission
PO Box 1199
Dickson ACT 2602

Copies of the revisions applications and associated documents are available from the Commission's website. Copies of this Draft Decision may also be obtained from the Commission by contacting Ms Rebecca Khair on telephone (02) 6243 1233, fax (02) 6243 1205, e-mail: rebecca.khair@accc.gov.au. Copies of the revisions applications on computer disk can also be obtained from Ms Khair.

Any other inquiries should be directed to Mr Michael Walsh on (02) 9230 9156.

2. Background

The PTS and the WTS were both owned by the Victorian Government entities Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd at the time the Commission approved the PTS and the WTS natural gas transmission access arrangements in 1998. Ownership of these pipelines subsequently passed to GPU GasNet Pty Ltd and then to GasNet Australia (Operations) Pty Ltd (GasNet). VENCorp remains the independent system operator of the PTS.

The Victorian Government enacted the Gas Pipelines Access (Victoria) Law, effective 1 July 1997, which brought the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code) into force in Victoria (though certain provisions of the Victorian Code were grandfathered until the first scheduled review).

2.1 Victorian gas industry structure and regulatory framework

Relevant aspects of the Victorian gas industry structure include:

- GasNet owns the PTS in Victoria which until recently solely transported gas supplied from the Esso-BHP Billiton fields in the Gippsland Basin. VENCorp is independent system operator for the PTS. The subsequent completion of the Interconnect Pipeline and the Southwest Pipeline also allows Cooper Basin and Otway Basin gas to be supplied via the PTS;
- GasNet also owns the WTS which until recently solely transported gas supplied from the on shore Otway Basin gas fields to the western parts of Victoria. Since completion of the Southwest Pipeline, Gippsland Basin gas has been supplied via the WTS. The TXU owned Western Underground Storage (WUGS) facility provides a source of peak gas flows via the Southwest Pipeline. GasNet proposes that the WTS and the Southwest Pipeline be included from the start of the second access arrangement period in a single access arrangement for the PTS;
- since July 1998 the Interconnect Pipeline has linked the PTS with the Moomba to Sydney Pipeline (MSP) which is owned and operated by East Australian Pipeline Ltd (EAPL), an entity owned by the publicly listed Australian Pipelines Trust (APT). The section of the Interconnect Pipeline from Barnawartha to Culcairn forms part of the PTS and is owned by GasNet and operated by VENCorp. EAPL owns and operates the remainder of the Interconnect Pipeline from Culcairn to Wagga Wagga. The pipeline allows southward flows of gas supplied by the Cooper Basin producers to Victoria and for northward flows of Gippsland Basin gas to NSW;
- Duke Energy International (DEI) owns and operates the Eastern Gas Pipeline (EGP) which commenced operations supplying Gippsland Basin gas to customers in NSW in 2000. In 2002, DEI commenced construction of a pipeline that will deliver Gippsland Basin gas to Tasmania; and
- a number of new gas sources, located primarily in the Otway Basin, are expected to commence supply to the GasNet system and to South Australian customers in the short to medium term.

The main legislation and relevant documents regulating access to the Victorian gas transmission industry are:

- the Code, under which transmission service providers are required to submit access arrangements and revised access arrangements to the Commission for approval;
- the *Gas Pipelines Access (South Australia) Act 1997*; and
- the *Gas Pipelines Access (Victoria) Act 1998*.

In addition, certain provisions of the Victorian Code under which the Commission approved the PTS access arrangement in December 1998 have been grandfathered. Sub-section 24A(3) of the *Gas Industry Acts (Amendment) Act 1998* provides that access arrangements approved under the Victorian Code (such as the access arrangements for the PTS and WTS) continue to be subject to sections 3 and 8, and 9 (so far as it applies to sections 3 and 8) and to sections 2.33 and 2.48A of the Victorian Code. These sections are not subject to the corresponding provisions of the Code until the first scheduled review of the access arrangements under section 2 of the Code. The convention has been adopted in this Draft Decision of identifying relevant Victorian Code provisions where they differ from current provisions of the Code.

The Code and appeals bodies in Victoria with respect to transmission pipelines are:

- the Commission – regulator and arbitrator;
- the National Competition Council – Code advisory body;
- the Commonwealth Minister – coverage decision maker;
- the Federal Court – judicial review; and
- the Australian Competition Tribunal – administrative appeal.

Reflecting institutional arrangements imposed by the Victorian Government at the time of its reform and privatisation of the formerly Government owned integrated gas supply business in 1998 and 1999, parts of a number of regulatory instruments are currently included in the access arrangements. Further, as noted earlier, while GasNet owns the PTS and the WTS, the Victorian Government gave VENCorp the role of independent system operator for the PTS. Under the terms of the Code, both GasNet and VENCorp are service providers. Their access arrangements allocate responsibility between them for complying with the obligations imposed by the Code.

2.2 The initial access arrangement assessment

On 16 December 1998, the Commission approved the following Victorian gas transmission access arrangements under provisions of the *Victorian Third Party Access Code for Natural Gas Pipeline Systems* (Victorian Code) with initial access arrangement periods ending on 31 December 2002:

- access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System (PTS);
- access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System (WTS);

- access arrangement by Victorian Energy Networks Corporation (VENCorp) for the PTS.

2.3 Broad issues

2.3.1 Merging of the GasNet access arrangements

GasNet proposes to merge the PTS access arrangement and the WTS access arrangement into a single GasNet access arrangement with effect from 1 January 2003. At the time the access arrangements were approved in 1998 the two systems were physically separate. Following the completion of the Southwest Pipeline in 1999, they are now physically interconnected. As part of the merger, the capacity management system for the WTS would change from contract carriage to the market carriage system applicable on the PTS.

GasNet identifies advantages in merging the PTS and WTS access arrangements, in particular, that a merger would:

(a) simplify access regulation for all parties;

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

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

(d) consistent with interstate practice, ensure there is one transmission access arrangement for each major pipeline system.[2]

GasNet proposes the following process:

- terminate the WTS Agreement between GasNet and TXU;
- revise the PTS and WTS access arrangements to merge them;
- VENCorp exercises its right under the WTS Approved Connection Deed to declare the WTS to be part of the 'gas transmission system', with effect from 1 January 2003. GasNet states that the WTS would be automatically covered by the PTS access arrangement; and
- apply the principles contained in section 8.9 of the Code to determine the capital base of that part of the enlarged PTS constituted by the current WTS.

A number of interested parties commented on GasNet's proposal. While there is support in principle for introducing a single consistent capacity management system across GasNet's system, some reservations were expressed about its implementation.

Of particular concern to a number of parties was that the merging of the two access arrangements should not give rise to any cross-subsidisation between the PTS and the WTS.[3] It was also suggested that greater transparency was needed in terms of the

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2 GasNet submission, 27 March 2002, p. 24.

3 For example, BHP Billion submission, 17 May 2002, p. 10; Amcor and PaperlinX submission, 24 June 2002, p. 9.

benefits of including the WTS in the PTS asset base.[4] Another party expressed concern that TXU would maintain its current monopoly of firm transportation capacity on the WTS consequent to the proposed allocation of Authorised Maximum Daily Quantity (AMDQ) credits, and suggested that they might instead be allocated to end-users.[5]

TXU advised in its submission that it was satisfied that work completed to date on the allocation of AMDQ credits was expected to preserve its pre-existing contractual rights with respect to the WTS.[6] TXU advises that it will terminate the WTS Agreement provided the Commission approves GasNet's merger proposal as part of its revised access arrangement and that the Service Envelope Agreement (SEA) 'is amended to VENCorp's satisfaction to ensure that the WTS and associated assets, performing to acceptable standards, are incorporated in the system operated by VENCorp under the MSO Rules'.[7]

In considering concerns expressed that TXU would maintain its current monopoly rights to firm capacity on the WTS, the Commission is cognisant of the requirement under section 2.47 of the Code that it must not approve revisions to an access arrangement if they would have the effect of depriving a person of a pre-existing contractual right (other than an exclusivity right which arose on or after 30 March 1995). The Commission considers that the proposed approach suitably maintains existing rights. It is not aware of any feasible alternative approaches that would preserve existing rights.

The Commission is aware of a proposal currently before the National Gas Pipelines Advisory Committee (NGPAC) to amend the Code so that it would specifically provide for the merging of two or more access arrangements.[8] It is the Commission's view that current Code provisions need not preclude it from approving revisions to the PTS and WTS access arrangements in the form of a single document covering both the PTS and the WTS. However, the relevant provisions and principles of the Code must be satisfied. The Commission's assessment of the merger proposal in terms of its impact on the capital base and on reference tariffs is set out in chapters 4 and 8 respectively.

One of the issues identified by NGPAC was that a merger could alter patterns of cost allocation and revenue recovery and, potentially, stranded asset risk. NGPAC raised the issue of whether there would be a need 'to balance the issues arising from any winners and losers created by the merging of Access Arrangements applying to two or more Covered Pipelines.'[9]

The Commission has considered the potential costs and benefits of merging the access arrangements. It proposes to accept GasNet's proposal that the revised access

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4 ENERGEX submission, 9 May 2002, p. 6.

5 EnergyAdvice submission, 30 May 2002, pp. 7-8.

6 TXU submission, 31 May 2002, p. 5.

7 ibid., 31 May 2002, pp. 5-6.

8 NGPAC, *Information Memorandum: Proposed Amendment to the National Third Party Access Code for Natural Gas Pipeline Systems*, April 2002.

9 ibid., p. 4.

arrangement will be in respect of both the PTS and the WTS. However, it has concerns about the potential impact of a merger on existing customers' expectations and rights.

The Commission generally is of the view that the merger of two or more access arrangements should not result in a substantial net transfer of risks or costs between customers. Nonetheless, some shifts may be acceptable in view of overall benefits expected from the merger (such as from administrative and regulatory efficiencies).

When the Commission approved separate access arrangements for the PTS and the WTS in 1998 it noted the expectation that the two systems would become physically connected in the future. It also noted the expectation that the WTS would become a market carriage pipeline and its access arrangement would be amended accordingly.[10]

Although two separate proposed access arrangements were submitted for approval in 1997, the Commission assessed the applications through a joint approval process. The WTS was treated as one of nine tariff zones. While the tariffs approved at the time were generally cost-reflective, the methodology adopted allowed some transfer of costs. For example, the use of ORC to allocate costs across the combined systems meant that capital costs associated with newer assets would also be paid for by customers using older assets.

Separate K factor mechanisms were approved as part of the tariff control formulae for the two access arrangements. As a result, revenue under or over recoveries as a result of product mix varying from forecasts could only be recouped from tariffs paid by the respective access arrangement's users. Accordingly, the current arrangements do not allow any 'cross subsidy' through the K factor mechanisms between the two systems.

The operation of the K factor mechanism is discussed in chapter 6. The Commission assessed proposals by interested parties to quarantine the costs of certain assets. It concluded that these proposals would be likely to result in unacceptable additional costs. Accordingly, it does not propose that the WTS or any other assets be quarantined from the PTS K factor mechanism in future.

2.3.2 Regulation of GasNet's Dandenong LNG facility

Clause 4.2 of the Market and System Operations Rules (MSOR) governs the obligations of VENCorp, GasNet and retailers in relation to GasNet's Liquefied Natural Gas (LNG) storage facility located at Dandenong. In particular, GasNet is required to make available to VENCorp 3 000 tonnes of LNG storage capacity for use by VENCorp to meet its operational requirements and to ensure the security of the gas transmission system.

The role of the system security reserve is to allow the maintenance of adequate system pressures in the event of a major emergency requiring a complete shutdown of the system so that customer load can be disconnected safely.

VENCorp currently pays GasNet $1.4 million a year for LNG storage which it recoups from its users through a commodity based charge. The balance of the facility's 12 000

[10] ACCC, 1998 Final Decision, p. 7.

tonne capacity is currently contracted to the three foundation retailers. The LNG facility is regulated under the Tariff Order until 31 December 2002.[11]

Clause 4.2 of the MSOR sets out the rights and responsibilities of GasNet, VENCorp and market participants relating to the operation of the LNG storage facility and the provision of LNG storage services. Pursuant to clause 4.2.5(b) an amount of 3 000 tonnes of LNG storage capacity is currently set aside as a system security reserve. VENCorp is obliged to maintain this amount in reserve and currently has a contract (put in place by the Victorian Government) with GasNet, the sole provider of LNG storage, to provide this capacity. The Commission understands that VENCorp is currently negotiating terms with GasNet for the future supply of system security reserve LNG capacity.

A number of interested parties consider that GasNet is in a position to exercise market power in the supply of LNG services in relation to the PTS, in particular, with regard to the system security reserve. Alternative sources of peak gas such as the WUGS are not seen as a complete substitute for the Dandenong reserve at present because of factors such as location, slower response times and the amount of capacity likely to be available.

VENCorp commissioned a study by Charles River Associates which stated in the introduction that:

> VENCorp has undertaken a risk review based on a single event analysis (n-1) and has modelled a set of contingency scenarios in consultation with the Gas Market Consultative Committee (GMCC) and the Office of Gas Safety (OGS). This indicated that the minimum reserve for the LNG facility under these conditions should be 3,000 tonnes of LNG and this has been accepted by the industry. This means that the 3,000 tonnes of LNG reserve will be held out of the market and never used in the market, but rather will be reserved solely for system security purposes.[12]

The study confirmed the requirement to retain a reserve level of 3 000 tonnes and further noted that the refill rate was critical to ensure that sufficient reserves remained available for multiple contingencies.

ENERGEX has submitted that there is a need to continue to regulate prices with respect to the system security reserve but not for the balance of the capacity of the Dandenong facility.[13] ENERGEX asked that the Commission satisfy itself that the price negotiated for the system security reserve is 'fair and reasonable' and stated its preference for regulation 'as long as it is a monopoly activity.'[14] Pulse has suggested that the system security reserve could be considered to be 'a required ancillary service and therefore not subject to normal commercial negotiations'.[15] Pulse considers it would be improper for GasNet to price this capacity to make up for any revenue shortfall.[16] TXU considers, depending on the outcome of the commercial negotiations between GasNet

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11 The system security component is currently regulated as a 'scheduled excluded service' while the remainder is regulated as an 'non-scheduled excluded service'.

12 Charles River Associates, *Victorian gas systems security cost benefit risk analysis*, March 2002, p. 5.

13 ENERGEX submission, 9 May 2002, p. 3.

14 ibid., p. 7.

15 Pulse submission, 16 May 2002, p. 4.

16 ibid., p. 5.

and VENCorp targeted for June 2002, it may be appropriate for the Commission to consider inclusion of LNG storage for system security purposes as a reference service.[17]

The provisions of the Tariff Order under which the Commission currently regulates LNG storage for system security purposes are scheduled to cease to have effect after 31 December 2002. Accordingly, the Commission has considered suggestions that it may be appropriate for it to continue to regulate these services in terms of the provisions of the Code and the Gas Pipelines Access Law (GPAL).

For this reason, the Commission has considered whether the Dandenong LNG reserve is part of the PTS. Schedule A to the Code lists pipelines such as the PTS which were covered from the commencement of the Code. However it does not provide details of the individual assets included. For the purposes of the Code:

> "pipeline" means a pipe, or system of pipes, or part of a pipe, or system of pipes, for transporting natural gas, and any tanks, reservoirs, machinery or equipment directly attached to the pipe, or system of pipes, but does not include—
>
> (a) unless paragraph (b) applies, anything upstream of a prescribed exit flange on a pipeline conveying natural gas from a prescribed gas processing plant; or
>
> (b) if a connection point upstream of an exit flange on such a pipeline is prescribed, anything upstream of that point; or
>
> (c) a gathering system operated as part of an upstream producing operation; or
>
> (d) any tanks, reservoirs, machinery or equipment used to remove or add components to or change natural gas (other than odourisation facilities) such as a gas processing plant; or
>
> (e) anything downstream of the connection point to a consumer;[18]

From this definition, it is apparent that tanks and reservoirs directly attached to the GasNet system would be covered providing *inter alia* that they did not change natural gas. However, liquefaction and subsequent vapourisation processes carried out at the Dandenong facilities could be viewed to constitute changes to natural gas in terms of temperature, pressure and phase transition chemistry. Consequently, legal advice considered by the Commission is that the facilities are not part of a covered pipeline. The Commission also noted that the reservoir is connected to the system by liquefaction and vapourisation equipment rather than being directly attached.

The Commission has also considered whether the LNG system security reserve is an ancillary service for the purposes of the Code. Its legal advice is that the Code is unclear in this area. The Commission does not propose that it regulate the LNG system security reserve once the relevant provisions of the Tariff Order cease to have effect.

2.3.3 Market carriage

The Victorian Government proposed the adoption of a market carriage capacity management system for the PTS as part of its reforms of the Victorian gas industry. The Commission considered opposing views from interested parties on the merits of this system as part of its approval of the transmission access arrangements in 1998. For example, supporters considered that market carriage could provide retailers and their

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17 TXU submission, 31 May 2002, p. 15.

18 Part 1 of Schedule 1 to the *Gas Pipelines Access (South Australia) Act 1997*.

customers with a sufficient degree of certainty of access to transmission services and that it would facilitate entry and exit by participants. In contrast, opponents suggested that the proposed approach was novel, untried and complex, and that it would inhibit interstate trade in natural gas as other states would adopt the alternative contract carriage approach.

The Commission concluded that the Victorian market carriage approach is consistent with the Victorian Code's guiding principles and criteria. It also concluded that interstate trade was unlikely to be hindered by the different systems in Victoria and other states. Accordingly, it approved the PTS access arrangements incorporating the market carriage capacity management system.

Both GasNet and VENCorp have proposed to continue under the market carriage capacity management system. Pursuant to section 3.8 of the Code, the Victorian and NSW Ministers have given notice to the Commission permitting use of the market carriage model for the second access arrangement period for those parts of the PTS in their respective jurisdictions. In addition, the Commonwealth Minister certified the Victorian gas access regime as effective in accordance with s. 44N of the *Trade Practices Act 1974* in March 2001.

The Commission is aware that a number of interested parties continue to hold concerns about the current market structure.[19] However, s. 205 of the Victorian *Gas Industry Act 2001* (GIA) requires that a review of Part 8 of that Act, which covers VENCorp's operations and functions, must be undertaken in 2007 and completed by 31 December 2007. The review will address whether or not there is a continuing need for VENCorp, or a similar statutory authority. It must have particular regard to the competitiveness of markets for and in relation to gas. The Commission expects that the review will examine the overall market structure and operations in Victoria, including the market carriage capacity management system and the role of VENCorp as independent system operator. Accordingly, the Commission does not propose to assess the current market structure or the relative merits of the two capacity management systems as part of the current review.

2.3.4 Interaction with VENCorp's access arrangement

Under GasNet's proposals, a single PTS access arrangement would apply from the beginning of the second access arrangement period, with GasNet the owner, and VENCorp the operator.[20]

Users relate directly with GasNet in relation to connection to the physical pipeline system, while their relationship with VENCorp is principally in terms of its market role.

VENCorp's ability to perform its statutory role as independent system operator is dependent on GasNet and the SEA. Hence, clause 5.1.1 of the MSOR requires that a SEA be in force at all times under which GasNet:

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[19] See for example, EAG submission, 31 May 2002, p. 1.

[20] GasNet, rather than VENCorp, currently operates the western system.

> agrees, amongst other things, to provide to VENCorp gas transportation services and pipeline capacity by means of the [PTS] pipelines".

TXU stated in its submission:

> TXU must deal regularly with GasNet. Through Gas Transportation Deeds and the Service Envelope Agreement, GasNet invoices TXU, and requires TXU to pay for Tariffed Transmission Services directly to GasNet. When TXU seeks a new connection, or additional capacity on the system, it must deal directly with GasNet.

Under the terms of the Code (sections 10.1 and 10.2), GasNet and VENCorp are 'multiple service providers' with responsibility for complying with the Code. Their PTS access arrangements allocate responsibility between them for complying with the obligations imposed by the Code. Currently, the GasNet and VENCorp PTS access arrangements each contain all the minimum elements set out in section 3 of the Code other than that responsibility for extensions and expansions is solely allocated to GasNet and responsibility for the queuing policy is allocated to VENCorp.[21] The Commission approved this approach in 1998 as it considered it provided an appropriate allocation of responsibility between the two service providers.[22]

VENCorp proposes to maintain the status quo for the second access arrangement period with regard to its relationship with GasNet. In contrast, GasNet proposes a number of changes. In particular, GasNet states that it is VENCorp that is responsible for the provision of the reference service and that GasNet does not propose to make any reference services available to users or prospective users under its revised access arrangement.[23] Accordingly, it would not specify the terms and conditions of supply of reference services.[24]

Clause 5.2.2 of the GasNet access arrangement currently states that it will make the tariffed transmission service available to VENCorp on the terms and conditions and in accordance with GasNet's reference tariff policy. GasNet's terms and conditions (clause 5.4.1) state that GasNet will make the PTS available to VENCorp as user in accordance with its obligations under the SEA and that VENCorp will then provide services to users of the PTS in accordance with the MSOR.

GasNet acknowledges that it provides services to VENCorp through the SEA but 'considers that the characterisation of the Reference Service and the description of VENCorp as "User" in the current Access Arrangement are inconsistent with the Code.'[25] GasNet considers that VENCorp already has its entitlement to system availability under the SEA and so does not need the current specification of the reference service. GasNet's reference service proposal is assessed in chapter 11.

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21 As the PTS is operated under a market carriage capacity management system, neither access arrangement is obliged to contain a trading policy.

22 The allocation is discussed in section 11.5 of this Draft Decision.

23 See section 11.1 of this Draft Decision.

24 See section 11.2 of this Draft Decision.

25 GasNet submission, 27 March 2002, p. 122.

Consistent with this approach, GasNet's access arrangement would not contain terms and conditions. GasNet's access arrangement would instead state that the terms and conditions on which the reference service is supplied are as set out in the MSOR.

VENCorp submitted that its preference is for the existing allocation to at least continue, such that both access arrangements would describe the reference services they provide and the associated terms and conditions. VENCorp considers that GasNet's access arrangement should include the SEA, either in full, or the key obligations.[26] VENCorp noted that GasNet accounts for around 85 per cent of the total annual transmission costs for the PTS and suggested it would be unacceptable if associated reference tariffs were not defined in GasNet's access arrangement. VENCorp expressed concern that GasNet might be able to alter its services such that they were in conflict with the statutory functions of VENCorp as operator of the PTS and that prospective users could be precluded from recourse to GasNet in regard to services it provides under the Code's access dispute processes.[27]

A number of other interested parties expressed support for the view put by VENCorp.[28]

The Victorian transmission access arrangements are unique in that there are two independent service providers, GasNet and VENCorp, providing third party access over the same system. In such a situation, the Code (sections 10.1 and 10.2) allows service providers to submit either a joint access arrangement or separate access arrangements. Under either approach, an appropriate allocation of responsibilities between the parties for complying with the Code is required. Where two separate access arrangements are submitted by multiple service providers the Commission must assess whether the access arrangements together meet the requirements of the Code. The Commission was satisfied that these conditions were met when it approved the access arrangements in 1998.

The Commission's strong preference is for multiple service providers to adopt an agreed allocation of responsibilities and a consistent approach when proposing access arrangements or revised access arrangements for approval. However, in this instance GasNet and VENCorp have been unable to agree on a consistent approach.

The Commission has carefully considered the service providers' proposed approaches, taking into account legal opinions provided to the Commission and the views of interested parties. The Commission notes that, apart from GasNet and its legal advisers, all views advanced supported GasNet continuing to provide a reference service.

The Commission has also considered the requirement under section 2.47 of the Code that it must not approve revisions to an access arrangement if they would have the effect of depriving a person of a pre-existing contractual right (other than an exclusivity right which arose on or after 30 March 1995). Consistent with the principle implicit in

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26 VENCorp submission, 13 May 2002, p. 4.

27 ibid., p. 4.

28 For example, ENERGEX submission, 9 May 2002, pp. 1-2; DNRE submission, 22 May 2002; Pulse submission, 16 May 2002, p. 3; TXU submission, 31 May 2002, p. 3; BHP Billiton submission, 17 May 2002, p. 9.

this provision, the Commission would be reluctant to approve revisions to access arrangements involving multiple service providers if the outcome would be to shift the balance of existing rights between those service providers without their agreement. In this instance VENCorp opposes such a change which it considers would prejudice its existing rights. The Commission's assessment of GasNet's services policy is provided in chapter 11 of this Draft Decision. Amendments are proposed to both service providers' proposals.

Part B – Tariff issues

3. Reference tariff methodology

3.1 Introduction

This chapter first assesses the reference tariff policy proposed by GasNet to apply during the second access arrangement period. It then considers the reference tariff approach proposed by GasNet to apply during that period. A number of changes are proposed for the revised reference tariff policy.

3.2 Reference tariff policy

3.2.1 Code requirements

Section 3.5 of the Code requires an access arrangement to include a policy describing the principles that are to be used to determine a reference tariff. This reference tariff policy must, in the regulator's opinion, comply with the reference tariff principles set out in section 8 of the Code.

Pursuant to section 8.47 of the Code, a service provider's reference tariff policy may provide that certain principles are fixed for a specified period and be not subject to change when it submits reviews to its access arrangement without its agreement.

3.2.2 Current access arrangement provisions

GasNet's reference tariff policies are currently described in clauses 5.3.2 to 5.3.8 of the PTS and WTS access arrangements which contain similar provisions.[29] These include:

- adoption of a CPI-X price path approach;
- the treatment of new facilities investment that does not satisfy the requirements of section 8.16 of the Code and the use of a speculative investment fund;
- adjustment of the capital base to take into account wholly or partly redundant assets;
- an incentive mechanism that allows GasNet to retain a share of returns achieved in the first access arrangement period in excess of anticipated returns;
- annual adjustment of tariffs in accordance with the price control formula. GasNet must provide the Commission with a statement proposing revised tariffs at least 30 business days prior to the commencement of the next regulatory year. The statement must demonstrate compliance with the price control formula. If the Commission has not notified GasNet that it has approved the proposed revised tariffs within 20 business days it is taken to have approved the proposed revised tariffs as of the 21st business day; and

29 Some aspects of the PTS access arrangement, such as the initial reference tariffs, and the methods applicable to changing reference tariffs, are contained in the Tariff Order.

- a tax events pass through mechanism that allows reference tariffs to be adjusted in line with increases or decreases in taxation affecting the provision of those references services without undergoing a review process under section 2 of the Code. GasNet may provide the Commission with a relevant statement providing details of the proposed pass through within three months of a change in taxes event occurring. If the Commission has not notified GasNet that it has approved the proposed pass through within 20 business days it is taken to have approved the proposed pass through as of the 21st business day. If a change in taxes pass through event occurs which is likely to affect GasNet but GasNet does not provide the Commission with a statement, the Commission may decide on a pass through amount and the basis on which it would apply.

GasNet's access arrangements currently include fixed principles which can be summarised as:

- use of incentive-based regulation under a CPI-X approach (not rate of return);
- an unchanging X factor over the second access arrangement period;
- adjustment of the initial capital base for inflation, depreciation, wholly or partially redundant assets and additions and disposals;
- a fair sharing of any benefits achieved through efficiency gains in later access arrangement periods;
- have regard to the need to take into account any K factor carryover;
- have regard to the cost of making, producing or supplying the goods or services which GasNet makes, produces or supplies;
- have regard to relevant benchmarks (including with regard to the level of executive remuneration); and
- that the Commission may issue statements of regulatory intent.

3.2.3 GasNet proposal

Clause 4.1 of GasNet's proposed revised access arrangement states that the access arrangement governs the transmission tariffs, which GasNet describes as being the portion of the reference tariff applicable to the tariffed transmission service.

GasNet (clause 4.2) states that the proposed initial transmission tariffs are set out in schedule 1 to the proposed revised access arrangement exclusive of GST. The transmission tariffs comprise rules and billing parameters, the GST-exclusive tariffs plus the amount of GST.

GasNet proposes that the tariffs will continue to vary on the basis of a price path approach whereby a set of prices and a price control mechanism are determined on an ex ante basis and the mechanism is not adjusted to account for subsequent events until the commencement of the next access arrangement period (clause 4.3).

Clause 4.4 states that the transmission tariffs have been determined on the basis of new facilities investment that is forecast to occur within the second access arrangement period and is reasonably expected to pass the requirements in section 8.16 of the Code.

GasNet proposes that it may submit revisions to its access arrangement during the second access arrangement period to increase the capital base of the PTS in recognition of further new facilities investment that satisfies section 8.16 of the Code.

Consistent with the access arrangements as they currently stand GasNet proposes that it may undertake new facilities investment that does not satisfy the requirements of section 8.16 of the Code, to which it refers as speculative facilities (clause 4.5). GasNet states that the portion of the new facilities investment which does satisfy the requirements of section 8.16 of the Code may, on a revision application by GasNet, be incorporated into the capital base and would form part of the speculative investment fund and may be subsequently added to the capital base if at any time the type and volume of services provided using the increase in capacity attributable to the speculative facilities change such that any part of the speculative investment fund would then satisfy the requirements of section 8.16. The amount of the speculative investment fund would be calculated in accordance with section 8.19 of the Code.

GasNet (clause 4.6) proposes that the Commission would continue to review, and if necessary, adjust the capital base (at the start of the next access arrangement period) to take account of wholly redundant assets. It would no longer allow an adjustment for partially redundant assets.

GasNet (clause 4.7) proposes that the incentive mechanism currently included in the access arrangement be retained but in revised form (see schedules 3 and 4 of the proposed revisions and section 6 of this Draft Decision).

GasNet proposes to revise its current tax pass through mechanism such that decreases in tax would only be recognised as net adjustments to tax increases (see clauses 4.9 and 6). It also proposes that the mechanism apply to changes in events and insurance costs. Following receipt of a statement from GasNet, the Commission would determine:

- if the specified event has occurred, or will occur;
- the pass through amount; and
- the manner in which the pass through amount would be applied.

In a response to submissions, GasNet clarified that the common feature of these pass through events is that they are all beyond the companies control.[30]

GasNet's proposed pass through amount and manner in which it would be applied would be taken to be approved if the Commission did not notify GasNet that it did not approve the statement within 20 business days of its receipt.

GasNet also proposes a zone change mechanism that allows GasNet to submit revisions if it believes that zones specified in schedule 2 require amendment (see clause 4.10). In response to receipt of a statement from GasNet the Commission must decide whether to approve the amendment and ensure that the amendment is consistent with the cost allocation methodology used to determine tariffs. As with the pass through, the proposed zone change amendment would be taken to be approved if the Commission

30 GasNet response to submissions, 12 June 2002, p. 15.

does not notify GasNet that it did not approve the statement within 20 days of its receipt.

Under clause 3.3 of schedule 3 to GasNet's proposed revised access arrangement an annual tariff adjustment would be taken to be approved if the Commission did not notify GasNet that it did not approve the statement within 15 business days of its receipt.

GasNet states that any amendment to the transmission tariffs in the second access arrangement period made under or as contemplated by clauses 4.2, 4.3, 4.7, 4.9, 4.10 or 6 constitutes an amendment under GasNet's reference tariff policy and does not constitute a revision of its access arrangement under the terms of the Code.

In addition, the proposed revised reference tariff policy includes the following fixed principles for the second access arrangement period (to apply for the third access arrangement period):

- the Commission would include in the reference tariffs for the third access arrangement period an allowance for the K factor carryover adjustment based on actual figures (or estimates where actual figures are not available); and
- GasNet would be able to retain a reasonable share of the benefits of efficiency gains it achieves in the second access arrangement period. Efficiency gains would be calculated on the basis of the amount that the average forecast operating costs for the third access arrangement period are below the forecast operating costs for the last year of the second access arrangement period adjusted to account for additional workload.

3.2.4 Submissions

A number of parties commented on aspects of GasNet's proposed revisions to its reference tariff policy. Parties were generally supportive of the broad approach proposed including the use of a CPI-X price path methodology and incentive regulation. However, reservations were expressed on the details of a number of issues. These are generally considered under specific topics below.

VENCorp states that the proposed amendments to zones would have the potential to require VENCorp, distributors and retailers to put in place new business processes and IT systems.[31] VENCorp considers that GasNet's proposed mechanism for amending zones within an access arrangement period should provide for a process of public consultation.

BHP Billiton opposes the revised redundant capital policy proposed by GasNet. It suggests that partially used assets should be optimised so that fully utilised assets do not cross subsidise under utilised assets. The Energy Users Association of Australia (EUAA) expressed a similar view.[32]

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31 VENCorp submission, 13 May 2002, p. 12.

32 BHP Billiton submission, 21 June 2002, p. 30; EUAA submission, 11 July 2002, p. 8.

The Allen Consulting Group (ACG), on behalf of ExxonMobil, proposed that GasNet's redundant capital policy should specifically provide a mechanism that would apply to the Southwest Pipeline in the event that it were to be included in the capital base.[33] ACG is concerned that this investment will not in practice be viable and considers that, if this is the case, its costs should not be borne by other users of the PTS.

With regard to the pass through proposal, TXU submits that the pass through for tax increases seems reasonable, but a pass through for regulatory requirements and increased insurance premiums is not consistent with GasNet's incentive mechanism. TXU noted that if the Commission allows this mechanism, it should ensure that the appropriate level of consultation with users occurs prior to its approval, and that GasNet is only allowed to pass through the cumulative impact of any pass through event.[34]

Origin accepts the pass through mechanism in principle but suggested a number of changes to GasNet's proposal. Origin states that the pass through mechanism should be two-way so as to cover decreases as well as increases in costs, and contended that the 20 business day approval process be rejected in its current form.[35]

Pulse has submitted that the Commission should assess whether the inclusion of Insurance and Regulatory Events is consistent with the weighted average cost of capital (WACC) being claimed by GasNet, and that the widening of the definition of pass through events represents a move towards rate of return regulation.[36]

ENERGEX notes concern that user charges can increase without due regulatory process under the proposed pass through mechanism. It proposed that the Commission should make the pass through clause more consultative to allow those affected to have input into the decision making process.[37] VENCorp submitted that the definition of a Regulatory Event is very wide under the GasNet proposal, and argued that the GasNet proposal appears open-ended, lacks transparency and could allow GasNet to introduce tariff increases without any consultation. VENCorp proposes that the Gas Marketing Committee and MSOR change process provide forums whereby GasNet can raise any increases in costs.[38]

3.2.5 Commission's considerations

The Commission's considerations of a number of these proposals is included as part of broader assessments under specific topics later in this document. In particular:

- the treatment of new facilities investment is considered in section 11.3;
- K factor carry over is considered in chapter 6; and

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33 ACG, *Implementation of incremental pricing for the Southwest Pipeline* (ExxonMobil submission, 5 June 2002), p. 24.

34 TXU submission, 31 May 2002, pp. 26-27.

35 Origin submission, 17 May 2002, p. 3.

36 Pulse submission, 16 May 2002, p. 4.

37 ENERGEX submission, 9 May 2002, p. 5.

38 VENCorp submission, 13 May 2002, p. 13.

- incentive mechanisms are discussed in chapter 10.

Other proposals are assessed in this section.

The Commission notes that the broad approach proposed of CPI-X price path methodology and incentive regulation is generally uncontroversial.

Redundant capital policy

Consistent with the current provisions of the access arrangements, under clause 4.6 of the proposed revised access arrangement, the Commission would continue to be able to adjust the capital base for wholly redundant assets at the start of the next access arrangement period. However, it would no longer be able to make an adjustment for partially redundant assets.

The Commission has considered GasNet's view that the ability to adjust for partially redundant assets may create uncertainty because it considers that it is not clear what extent of redundancy is allowed before an asset is to be removed from the capital base. The Commission notes that GasNet questions whether partial utilisation of a particular pipeline in a particular year could result in the pipeline being excluded from the asset base.

The Commission considers that GasNet's concerns about the potential treatment of partially redundant assets suggest an exaggerated application of Code provisions. Most importantly, section 8.27(b) of the Code is relevant to partial utilisation which indicates a sharing of costs associated with a decline in the volume of sales rather than complete exclusion of assets from the capital base. In addition, the Commission considers that redundancy is a forward-looking concept. While historical performance may be a useful indicator of likely future performance, it is the expectation of future usage that the Commission must assess when considering redundancy. Further, the Commission is of the view that an adjustment for redundant capital would only be made if there is a reasonable expectation of a permanent reduction in usage. Nonetheless, it notes that section 8.28 allows for assets where they have been treated as redundant capital but are subsequently used, or used to a greater extent, to be readmitted to the capital base.

The Commission acknowledges that the current provisions of GasNet's access arrangement with regard to capital redundancy involve elements of uncertainty for GasNet. However, it considers that partial redundancy provisions can provide an important safeguard for users, particularly with capital intensive network infrastructure such as the PTS. Even in the face of apparent redundancy, it may be commercially viable to continue some residual usage of these systems. A policy that only removed totally redundant capital from the asset base might in practice provide little protection for users who would pay tariffs to recover the total cost of partially redundant assets. The Commission also notes that in general, the existence of a capital redundancy policy puts pressure on a service provider to ensure that its investments are appropriate.

The Commission is not persuaded that it should agree to the risks associated with partial redundancy being fully shifted to users. Accordingly, the Commission proposes that GasNet retains its current redundant capital policy.

Proposed amendment 1

GasNet must amend clause 4.6 of its revised access arrangement so that the redundant capital policy applies to both partial and wholly redundant assets.

Pass through and zone change mechanisms

The Commission has considered GasNet's proposed pass through and zone change mechanisms and the proposed changes to annual tariff review procedures. Changes under these provisions are not considered by GasNet to be revisions to the access arrangement.

The Commission notes that GasNet responded to VENCorp's concerns about the need for public consultation in relation to individual pass through events as follows:

> It is within the discretion of the Commission to withhold its approval pending consultation. The proposal as put by GasNet gives the Commission the discretion to decide its course of action based on the materiality of the proposed changes.[39]

The Commission agrees that it should have the discretion to conduct a process of public consultation in response to proposals under these proposed provisions. It notes that the Code (section 2.33(b)) specifies a public consultation process for revisions that are material and for all changes to reference tariffs and reference services. However, GasNet's proposal makes no explicit allowance for such a process and the proposed timeframes would appear inadequate to allow for consultation or other aspects of due process which may be needed if the Commission accepts GasNet's expanded tariff change proposals. The Commission is of the view that the existing timeframes have been adequate for the limited assessment associated with annual tariff adjustments and tax events pass through.[40] However, it seems likely that the proposed expanded scope of these change mechanisms could require a broader assessment.

In practice, under GasNet's proposals, in order to allow sufficient time for due process (including public consultation as appropriate) on a specific proposal put forward by GasNet, the Commission would need to decide to not approve a proposal and notify GasNet accordingly. This process could be repeated until sufficient time had elapsed for public consultation to be completed and for the Commission to decide to approve the proposal. The Commission considers that this process would be unnecessarily constraining and unwieldy. Accordingly, it has proposed changes to streamline the process and to provide adequate time to allow due process. Circumstances which may warrant an extended assessment period include proposals that are complex and where inadequate information is provided.

Proposed amendment 2

GasNet must amend clauses 4.10 and 6.2 of its revised access arrangement to provide an assessment period of 40 business days. It must also allow the Commission, at its discretion, to extend the period to adequately assess pass through and zone change proposals.

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[39] GasNet response to submissions, 12 June 2002.

[40] The Commission has 20 business days to approve proposed revised tariffs.

GasNet has proposed that the Commission approve only positive pass through amounts (clause 6.4). In a response to submissions, GasNet supports its case by arguing that a negative pass through would encourage disputes from users, and that any pass through event must take into account the effect of any previous event, including negative events.[41]

The Commission does not accept this proposal. As submitted by Origin, a pass through mechanism should be symmetrical in that it would apply to both increases and decreases in costs. An amendment is proposed accordingly.

Proposed amendment 3

GasNet must amend clause 6.4 of its revised access arrangement, the pass through mechanism, to allow both positive and negative pass through amounts.

The Commission notes that the Essential Services Commission (ESC) considers that similar pass through mechanisms proposed by the three Victorian gas distribution businesses should provide a mechanism to allow it to initiate pass through reviews.[42] This amendment has been proposed as the ESC considers it would be unlikely for a service provider to initiate a pass through that will lead to a decrease in reference tariffs. The Commission concurs with the ESC. Consequently, the Commission proposes an amendment that would allow it to initiate pass through reviews.

Proposed amendment 4

GasNet must amend clauses 6.1 and 6.2 of its revised access arrangement, the pass through mechanism, to allow the Commission to initiate a pass through review.

While the Commission has some concerns about the muting effect that a pass through mechanism would have on incentives, it recognises that the Code (section 8.2) explicitly allows for a cost of service methodology (section 3.3 of this Draft Decision).

GasNet has proposed that the pass through mechanism would operate for three categories of events: a change in taxes event, a regulatory event and an insurance event. The Commission considers that it is not unreasonable to allow a pass through mechanism for these events as it can provide a cost-effective approach to dealing with uncertain future costs. However, it is the view of the Commission that the specifics of the pass through mechanism should be amended.

In relation to the Change in Taxes Event, GasNet defines such an event as:

> (a) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of Relevant Tax); or
>
> (b) the imposition of a new Relevant Tax,
>
> to the extent that the change or imposition:
>
> (c) occurs after the Commencement Date; and

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[41] GasNet response to submissions, 12 June 2002, p. 15.

[42] ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 166.

(d) results in a change in the amount GasNet is required to pay or is taken to pay (whether directly or under any contract) by way of Relevant Taxes.[43]

GasNet defines a Relevant Tax as:

> any tax, rate duty, charge, levy or other like or analogous impost paid or taken to be paid by GasNet associated with the Tariffed Transmission Service, but excludes income tax and capital gains tax.[44]

The Commission is of the view that GasNet's definition of a Change in Taxes Event is not appropriate as it excludes a provision for the removal of a tax (making the approach asymmetrical), and that the proposed definition of a Relevant Tax is too broad. It therefore proposes that the definition of a Change in Taxes Event be amended so that (b) reads 'the removal or imposition of a *Relevant Tax*', and the following definition of Relevant Tax, which is based on the wording of the current Tariff Order be used:

> *Relevant Tax:*
>
> Any tax but excluding any:
>
> (a) income tax (or State equivalent income tax), fringe benefits tax or capital gains tax;
>
> (b) payroll tax;
>
> (c) fees and charges paid or payable in respect of a *Regulatory Event*,
>
> (d) land tax or any other tax on the ownership or occupancy of premises;
>
> (d) customs and import duty;
>
> (e) municipal rates, taxes and other charges imposed by local authorities;
>
> (f) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties;
>
> (g) penalties and interest for late payment relating to any tax; or
>
> (h) any tax that replaces any of the taxes referred to in (a) and (g),
>
> and in this definition, 'tax' includes any rate, duty, charge or other like or analogous post.

A similar approach has also been proposed by the ESC for the three Victorian gas distribution businesses.

The Commission considers that in order to make an informed decision on whether the pass through event proposed is appropriate, GasNet must provide to the Commission sufficient documentary evidence which substantiates that the aggregate tax costs facing GasNet has increased or decreased. It is proposed that GasNet amend its access arrangement to provide for this information.

In relation to a Regulatory Event, GasNet defines such an event to mean:

> A decision made by the Commission or any other Authority or any amendment to an Applicable Law after the Commencement Date that has the effect of:
>
> (a) imposing minimum standards (including safety or technical standards) on GasNet relating to the Tariffed Transmission Service that are different from the set of minimum standards imposes on GasNet associated with the Tariffed Transmission Service at the Commencement Date;

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43 GasNet access arrangement, 27 March 2002, p. 12.

44 ibid., p. 14.

(b) altering the nature and scope of the services that comprise the Tariffed Transmission Service; or

(c) substantially varying the manner in which GasNet is required to undertake any activity forming part of the Tariffed Transmission Service from the Commencement Date,

As a result of which GasNet incurs materially higher costs associated with the Tariffed Transmission Service that it would have incurred but for that event.[45]

It is the view of the Commission that the definition of a Regulatory Event should be amended to incorporate both increases and decreases in regulatory requirements. It also proposes that appropriate amendments to GasNet's access arrangement be introduced to require the submission of sufficient information when a pass through event statement is provided to the Commission. This information should include documentary evidence outlining the impact of any proposed Regulatory Event on aggregate company costs.

GasNet defines an Insurance Event as:

Circumstances in which:

(a) there has been a change in one or more costs in the insurance comprising GasNet's Minimum Insurance Level; and

(b) as a result of that change, the aggregate costs of GasNet's Minimum Insurance Level exceeds the Benchmark Insurance Costs.[46]

The Commission is of the view that the definition of an Insurance Event should be amended to allow for a change in the Minimum Insurance Level that exceeds or falls short of the Benchmark Insurance Costs. As with the aforementioned pass through events, it is proposed that GasNet amend its access arrangement so that it is required to provide documentary evidence of a change in aggregate insurance costs to the Commission.

As discussed in chapter 6 of this Draft Decision, GasNet has sought a cash flow allowance for asymmetric risks. This allowance includes $140 000 for deductibles in current insurance policies held by GasNet pursuant to the SEA. The Commission considers that there is some uncertainty in regard to whether the allowance will be sufficient. As a result, the Commission proposes that the allowance not be included in the cash flows as proposed but actual expenditures be included in the pass through mechanism as an Insurance Event.

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45 ibid., p. 14.

46 ibid., p. 13.

Proposed amendment 5

GasNet must amend the following in its revised access arrangement:

- the definition of a Change in Taxes Event in clause 9.1 so that (b) reads 'the removal or imposition of a Relevant Tax';
- the definition of Relevant Tax so that it adopts the wording specified in section 3.2.5 of this Draft Decision;
- the definition of a Regulatory Event in clause 9.1 to allow for regulatory requirements that may result in either higher or lower costs for GasNet;
- the definition of an Insurance Event in clause 9.1 to allow for a changes in the Minimum Insurance Level that exceed or fall short of the Benchmark Insurance Costs;
- the definition of an Insurance Event in clause 9.1 to include the amounts currently identified in the asymmetric risk allowance as deductibles in current insurance; and
- clauses 6.1 and 6.2 to require the provision of sufficient documentary evidence which substantiates that the aggregate costs facing GasNet has increased or decreased as a consequence of the deemed pass through event .

The Commission's considerations regarding the annual tariff review are provided in section 8.2.5 of this Draft Decision.

3.3 Reference tariff methods

Section 8 of the Code sets out the general principles for a reference tariff and certain factors about which the relevant regulator must be satisfied before the regulator may approve reference tariffs and the reference tariff policy. The general principles are contained in sections 8.1 and 8.2 of the Code.

Section 8.3 of the Code states that, subject to requirements of that section and the objectives expressed in section 8.1, the method by which the reference tariff may vary within an access arrangement period through implementation of the reference tariff policy is within the discretion of the service provider. The Code suggests two alternative forms of regulation methodologies (but notes that there may be variations or combinations of these approaches):

- under a price path approach, tariffs are determined before the access arrangement period and follow a path which is not adjusted to take account of subsequent events until the start of the next access arrangement period; and
- under a cost of service[47] approach, tariffs are adjusted during the access arrangement period in light of actual outcomes (such as sales volumes and actual costs) to ensure that the actual costs of the services are recovered.

[47] The Code also uses the capitalised expression 'Cost of Service' in section 8.4 to refer to a methodology for determining total revenue.

GasNet states that tariffs will vary in accordance with a price path approach.[48] However, it has also proposed inclusion of a pass through mechanism to allow it to recover certain potential cost increases during the second access arrangement period which is consistent with a cost of service approach. The Commission considers that the proposed methodology would be most accurately described as a combination of the price path and cost of service approaches. Consideration of the tariff path is provided in section 8.3 of this Draft Decision.

Section 8.4 of the Code permits a choice of three methodologies for determining the total revenue which are termed Cost of Service[49], IRR and NPV.

The Cost of Service approach is described as one where the total revenue is set to recover the costs of providing services, with the costs being calculated on the basis of:

- a rate of return on the value of the capital base (the capital assets that form the covered pipeline);
- depreciation of the capital base; and
- non-capital costs (the operating, maintenance and other non-capital costs incurred in providing all services provided by the covered pipeline).

The rate of return is set to provide a return commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (sections 8.30 and 8.31 of the Code).

Under the IRR approach, total revenue is set to provide an internal rate of return (IRR) for the covered pipeline on the basis of forecast costs and sales, subject to the principles set out in sections 8.30 and 8.31 of the Code.

Under the NPV approach, total revenue is set to deliver a net present value (NPV) for the covered pipeline (on the basis of forecast costs and sales) equal to zero, using a discount rate that would yield a return consistent with sections 8.30 and 8.31 of the Code.

While these methodologies are different ways of assessing the total revenue, their outcomes should be consistent. For example, it is possible to express any NPV calculation in terms of a Cost of Service calculation by the choice of an appropriate depreciation schedule. In addition, other methodologies (such as a method that provides a real rate of return on an inflation-indexed capital base) are acceptable under section 8.5 of the Code, provided they can be translated into one of these forms.

GasNet proposes to retain the Cost of Service approach adopted for the initial access arrangement period. The Commission considers this is appropriate. GasNet’s proposals are considered in detail in the following sections.

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48 GasNet access arrangement, 27 March 2002, p. 5.

49 The Code also uses the uncapitalised expression ‘cost of service’ in section 8.3(a) to refer to a form of regulation sometimes referred to as rate of return regulation.

4. Capital base

This chapter deals with GasNet's proposals regarding the roll forward of the initial capital base established in the Commission's 1998 decisions. The Commission's assessment of GasNet's proposals for how the regulatory asset base would be rolled forward for the third access arrangement period is considered in chapter 3 of this Draft Decision.

4.1 Roll forward of the capital base

4.1.1 Code requirements

Section 8.9 of the Code states that (for the Cost of Service methodology) the capital base at the commencement of each access arrangement period after the first is determined as:

- the capital base at the start of the preceding access arrangement period; plus
- the new facilities investment (or the recoverable portion) in the preceding access arrangement period (adjusted as relevant as a consequence of section 8.22 to allow for the differences between actual and forecast new facilities investment); less
- depreciation for the preceding access arrangement period; less
- redundant capital identified prior to the start of the new access arrangement period.

4.1.2 Current access arrangement provisions

Fixed principle 3 in clause 9.2 of the current Tariff Order states that in determining price regulation in the subsequent access arrangement period, the regulator is to:

> (3) use the *capital base* for *TPA* at the start of the *initial regulatory period*, adjusted to take account of inflation since 1 January 1998, depreciation, wholly or partially redundant assets and additions and disposals in the ordinary course of business since 1 January 1998.

4.1.3 GasNet proposal

GasNet states that in the 1998 Final Decision, the Commission determined that the initial capital base (ICB) was valued at $363.7 million.[50] This valuation was based on a valuation by Gutteridge, Haskins and Davey Pty Limited (GHD) as at 30 June 1997 from which the value of easements ($40.2 million) and some pipeline regulators and associated remote terminal units ($1.9 million) were removed, some value from the WTS and Lurgi pipes was deducted to achieve lower tariffs on these assets ($9 million and $1.2 million respectively) and the value of the Murray Valley pipeline ($15.7 million) was omitted. Further, GasNet says the Commission incorrectly expressed the

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[50] ACCC, *Final Decision: access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System; access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System; and access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System*, 6 October 1998.

ICB as $363.7m in the 1998 Final Decision whereas it considers that the amount used to calculate the reference tariffs was $358.0 million.[51] GasNet proposes that the 'correct' capital base as at 1 January 1998 is $399.5 million. This is derived by adding the value of the easements and regulators (adjusted for depreciation and inflation to give a 31 December 1998 value) to the $358.0 million.

Table 4.1 shows adjustments made by GasNet for depreciation, inflation and capital expenditure since 1 January 1998 to give a regulatory asset base (RAB) at 1 January 2003 of $539.7 million.[52]

Table 4.1: Proposed roll-forward of the capital base

	$ million				
Year ending 31 December	**1998**	**1999**	**2000**	**2001**	**2002**
Opening capital base	399.5	431.2	518.1	537.7	542.3
Depreciation allowance	-13.8	-15.2	-17.0	-18.1	-18.3
Capital expenditure	39.0	93.3	6.2	4.5	0.6
Disposals/redundancies	-0.2	-0.2	-1.4	-0.1	-0.03
Inflation	6.6	9.0	31.8	18.4	15.2
Closing capital base	431.2	518.1	537.7	542.3	539.7

Source: GasNet access arrangement information, 27 March 2002, p. 4.

Subsequent to GasNet's lodgement of the proposed revisions to its access arrangements, the Commission has worked with GasNet to verify these figures. Several errors have been identified in the modelling by GasNet which produced the above figures. Consequently, GasNet has provided revised figures which are reproduced in Table 4.2 below.

[51] GasNet access arrangement information, 27 March 2002, p. 3; GasNet submission, 27 March 2002 pp. 29-30.

[52] GasNet submission, 27 March 2002, p. 5.

Table 4.2: Revised proposed roll-forward of the capital base

Year ending 31 December	$ million				
	1998	1999	2000	2001	2002
Opening capital base	399.2	430.3	516.9	534.5	537.6
Inflation	6.3	7.8	30.1	16.8	13.6
Depreciation allowance[a]	13.8	15.2	17.0	18.1	18.4
Capital expenditure[a]	38.7	94.1	6.3	4.6	0.7
Disposals/redundancies[a]			1.8	0.2	
Indirect asset allocation					0.5
Closing capital base	430.3	516.9	534.5	537.6	533.8

Source: GasNet Erratum, 19 July 2002.
Note: (a) These items are inflated to give an end of year value.

Indirect assets (such as the corporate headquarters building) are used by both the regulated and unregulated parts of GasNet's activities. Only a proportion of an appropriate return of and on capital should be recovered through the tariffs on reference services. As the nature of GasNet's business changes, so this proportion changes. An adjustment to the asset base needs to be made to reflect the change in the proportion of these assets that are appropriately in the RAB. In the above table, this adjustment is indicated in the line 'indirect asset allocation'.

4.1.4 Submissions

Interested parties generally raised concern about GasNet's proposal to reopen the capital base. TXU notes the significant potential impact on tariffs and submits that the approach is inconsistent with the Code and GasNet's current fixed principles.[53] TXU also states that including a value for easements would be counter to the policy of the Victorian Government at the time of privatisation and would result in a windfall gain to GasNet at the expense of consumers. ENERGEX does not believe that the Code permits the capital base to be reopened and proposes that GasNet be required to resubmit on the basis of the approved initial capital base.[54] Pulse states that the Code does not permit the capital base to be reopened, and that easements should not be included in the asset base because they are not owned by GasNet and they are not included in the GPAL definition of a covered pipeline.[55]

Pulse raises a number of further arguments against reopening the asset base, including that it would be inconsistent with the Code's spirit of certainty and consistency, and that, as GasNet purchased the business with parameters such as the capital base value in place, an increased valuation would lead to windfall gains for GasNet at the expense of retailers and consumers.[56]

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[53] TXU submissions, 3 May 2002, p. 1 and 31 May 2002, pp. 30-32.

[54] ENERGEX submission, 9 May 2002, p. 4.

[55] Pulse submission, 16 May 2002, p. 2.

[56] ibid., p. 3.

Origin states its understanding is that the Code does not permit reopening of the capital base and queried the argument put to it by GasNet that easements were included in the initial capital base with a value of $0.[57] Origin also questioned whether there had been a fundamental change in conditions that might justify reopening the asset base.

BHP Billiton states that the Commission accepted the GHD valuation adjusted by changes made by the applicant in 1998. Further, it is of the opinion that the Code does not allow a restatement of the asset base as proposed by GasNet.[58]

In addition, BHP Billiton, Amcor and PaperlinX believe that the GST spike should be removed from the escalation factors used in the calculation of the RAB.[59]

4.1.5 Commission's considerations

Initial capital base

The Commission carefully considered the merits of GasNet's proposal to reopen its regulatory asset base and to adjust it upwards by $41.2 million (to a January 1998 value of $399.2 million). The Commission considers that such a revaluation is unwarranted and would not be consistent with regulatory policy objectives. The Commission is satisfied that it correctly interpreted the requirements of the Victorian Code when it approved GasNet's predecessor's proposed valuation of the initial capital base in 1998. The valuation approved in 1998 was consistent with that proposed by the Victorian Government as owner at the time of the PTS and WTS. The subsequent purchases of these assets were made in the knowledge that the regulatory asset base had already been set.

In any case it is the Commission's understanding that it can only adjust the initial capital base in accordance with sections 8.9 and 8.15 to 8.29 of the Code. Consequently it cannot re-determine the initial capital base.[60] In other words, the Commission understands that the Code does not give it the discretion to make such an adjustment once the initial capital base has been established.

The Commission agrees with GasNet that the fixed principle relating to the roll forward of the ICB (see section 4.1.2 above) substantially restates the requirements of the Code.[61] To the extent that they do differ, the Commission is satisfied that the fixed principle does not place any further restriction or demand on it that the Code does not already do. Consequently, the fixed principle does not alter the above conclusion.

GasNet argues that the Code is not rigid or mechanical in its requirements for the calculation of the RAB as the intention of the Code would be to allow for the correction of what it describes as 'manifest errors'.

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57 Origin submission, 17 May 2002, p.6.

58 BHP Billiton submission, 21 June 2002, pp. 24-28.

59 BHP Billiton submission, 21 June 2002, p. 28; Amcor and PaperlinX submission, 24 June 2002, p. 22.

60 The Commission's legal advice on this can be made available to interested parties.

61 GasNet submission, 27 March 2002, p. 22.

Consequently, the Commission has carefully examined the relevant aspects of its 1998 decision documents. It has found no evidence of the 'errors' to which GasNet refers in relation to the differences between the GHD valuation and the ICB set by the Commission.[62] The Commission gave consideration at that time to these differences, which in large part were proposed by the applicant, and considers that the differences are deliberate and not errors.

Further, legal advice obtained by the Commission is that it cannot re-open the initial capital base. GasNet's predecessor had the opportunity at the time to seek review by the Australian Competition Tribunal of the ICB value approved by the Commission in 1998 but did not do so. The Commission was unaware of any disagreement with the approved valuation prior to discussions with GasNet in 2001.

The Commission considers that the 'mechanical' adherence to the capital base already established to which GasNet objects is one of the aspects of the Code that gives certainty to the regulated entity. It was strongly advocated by the pipeline industry. GasNet may consider proposing to NGPAC a change to these Code provisions.

GasNet claims that its approach (to adjust the capital base at the beginning of the previous access arrangement period) is consistent with section 2.24(a) of the Code which requires the Commission to take into account the legitimate business interests of GasNet. The Commission fails to see how maintaining the asset valuation adopted when approving the access arrangement in any way violates GasNet's legitimate business interests, especially as GasNet purchased the PTS as a going concern after the Commission approved the access arrangement and therefore was in full knowledge of the value of the RAB and the regulatory regime.

In the 1998 Final Decision, the Commission considered $363.7 million to be a fair value for the ICB, subject to two amendments: that actual inflation, rather than forecast, be used (along with the appropriate depreciation) to adjust the 1 July 1997 figures (the valuation date in the GHD report) to 1 January 1998; and that an appropriate proportion of indirect assets be allocated to excluded services.[63] The resulting figure was $358.0 million.[64] Thus GasNet is incorrect to claim that the Commission has inaccurately expressed the balance of these assets and is also incorrect to surmise that the $358.0 million represents the June 1997 value of the assets.

The Commission concludes that the appropriate RAB as at 1 January 1998 (the starting point for the calculation of the RAB at 1 January 2003) is the $358.0 million established in the Final Approval of 1998.

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62 ibid., p. 30.

63 Amendments 3.2 and 3.7 in ACCC, 1998 Final Decision, pp. 41 and 84.

64 See TPA access arrangement information, 30 November 1998 (on which the Final Approval of the Commission was based) Table 7, p. 4.

Proposed amendment 6
GasNet must calculate the roll forward of the regulatory asset base on the basis of the initial capital base of $358.0 million (at 1 January 1998) which was approved in the 1998 Final Approval.

Roll forward

As noted in 4.1.1 and 4.1.2 above, both the Code and the fixed principle 3 require the RAB at the beginning of 2003 to be calculated by adding new facilities investment to, and deducting depreciation and redundancies from, (all for the period 1998-2002) the ICB established in the first access arrangement period. The appropriate figures for capital expenditure and redundant assets are established below in sections 4.2 and 4.3 respectively. With regard to depreciation, it should be noted that the appropriate figure is not the actual depreciation derived by applying the depreciation rates to the various assets in the RAB. Rather, the correct figure is the depreciation forecast for 1998-2002 for the initial access arrangement period, restated for actual inflation during the period rather than the forecast inflation. Forecast depreciation is used because this is the amount which GasNet has been able to recover through the reference tariffs for 1998-2002. Any other figure would mean that at the end of the asset's life, total allowed depreciation would be different to the value of the asset. That is, the asset may have been depreciated more or less than its full value, which is not permitted by the Code (section 8.33(d)) and which would be inequitable for users or the service provider.

GasNet has calculated the roll forward of the RAB to produce a figure of $539.7 million at the end of 2002. This calculation was made in a detailed model which has been provided confidentially to the Commission. In its assessment of this model the Commission found several errors which, in the following discussions, GasNet has accepted. Consequently, GasNet provided a revised calculation of the roll forward of the RAB resulting in a proposed figure of $533.8 million at the end of 2002 (see Table 4.2). The Commission still considers this figure to overstate the value of the RAB at the end of 2002 for the following reasons:

- as noted above, the starting point at the beginning of 1998 (ICB) is overstated with the inappropriate inclusion of new assets;
- depreciation is overstated as it includes the depreciation of the assets GasNet proposed to include in the revised ICB; and
- the disposals figures are incorrect as they include disposals of assets GasNet proposed to include in the revised ICB.

Adjusting GasNet's revised proposal (Table 4.2) for these items mentioned above produces a RAB at the end of 2002 of $493.2 million, as indicated in Table 4.3 below.

Table 4.3: Roll-forward of the capital base

Year ending 31 December	$ million				
	1998	**1999**	**2000**	**2001**	**2002**
Opening capital base	358.0	389.8	476.9	493.4	496.5
Inflation	5.7	7.0	27.7	15.4	12.4
Depreciation allowance[a]	12.5	13.9	15.7	16.7	16.9
Capital expenditure[a]	38.7	94.1	6.3	4.6	0.7
Disposals/redundancies[a]			1.8	0.2	
Indirect asset allocation					0.5
Closing capital base	389.8	476.9	493.4	496.5	493.2

Source: GasNet Erratum 19 July 2002 adjusted by the Commission.
Note: (a) These items are inflated to give an end of year value.
Figures may not add up due to rounding errors.

However, it should be noted that the value of $493.2 million may be subject to some alteration for the Commission's Final Decision. The Commission is still assessing GasNet's model (the latest version having not been in the Commission's possession for very long at the time of writing this Draft Decision). In addition, as the ICB is not adjusted as GasNet proposed, the proportion of regulated assets to GasNet's total assets will be lower than that under GasNet's proposal. Consequently, the adjustment to the RAB for the allocation of indirect assets will also be lower than the $0.5 million proposed by GasNet. The Commission has not been able to model the new number and so has used GasNet's number in the above table.

The Commission notes that GasNet has used the CPI in calculating the inflation component. The Commission considers this is appropriate in order to maintain the real value of GasNet's capital.

4.2 New facilities investment

4.2.1 Code requirements

Section 8.16 of the Code allows the capital base to be increased by the actual cost of new facilities investment provided that this amount is not more than would be invested by a prudent service provider acting efficiently (acting in accordance with accepted good industry practice to achieve the lowest sustainable costs of delivering services), and provided one of the following conditions is satisfied:

i. anticipated incremental revenue exceeds the costs incurred (the economic feasibility test); or

ii. the new facility has system-wide benefits that justify a higher tariff for all users (the system-wide benefits test); or

iii. the new facility is necessary to maintain the safety, integrity or contracted capacity of services (the safety, integrity and contracted capacity test).

If the reference tariff policy allows the service provider to undertake new facilities investment which does not pass the requirements of section 8.16, then the portion of any such investment which does pass those requirements can be included in the asset base under section 8.18. The remainder (or a portion of it) may, if the reference tariff policy allows, be subsequently added to the capital base if it passes the section 8.16 requirements in the future under section 8.19.

4.2.2 Current access arrangement provisions

The reference tariff policies in the current access arrangements allow GasNet to undertake new facilities investment which does not pass the requirements of section 8.16. If the investment partially passes the economic feasibility test then the remainder may be included in the speculative investment fund (net of any recovery through a user capital contribution or a surcharge). However, unlike the Code, the reference tariff policies do not allow GasNet to include part of the investment in the capital base under the system-wide benefits test or the safety test and the balance in the speculative investment fund: the investment must completely pass either of these tests or not be included in the capital base at all.

4.2.3 GasNet proposal

GasNet states in its proposed revisions to its access arrangements that it has undertaken $199.67 million of capital expenditure in the first access arrangement period but is only seeking to include $143.6 million in the RAB. As noted above, GasNet has refined its modelling since it lodged its proposed revised access arrangement. As a result it has provided a revised disaggregation of its capital expenditure which differs slightly from that proposed in the access arrangement. These figures have been reproduced in Table 4.4 below. While GasNet notes expenditure on the Bulla Park and Young compressors, these are not part of the PTS. Accordingly, the costs and revenues associated with these assets are not relevant to GasNet's access arrangement.

Table 4.4: Actual capital expenditure, 1998 to 2002

Project description	$ million	
	Actual expenditure	Included in RAB
Gooding compressor automation	2.21	2.21
Brooklyn compressor automation	4.13	4.13
Brooklyn compressor restaging and gas cooler upgrade	1.85	1.85
Southwest Pipeline	82.80	75.50
Interconnect Assets	42.60	40.40
Bulla Park compressor	28.10	
Young compressor	19.56	
Murray Valley Pipeline	15.63	15.63
General maintenance capital expenditure	1.98	1.98
Non-system capital expenditure	1.17	1.17
Total	200.04	142.88

Source: GasNet Erratum, 19 July 2002.
Note: The total of the capital expenditure proposed to be included in the RAB will not equal the total of the expenditure in Table 4.2 as Table 4.2 figures are inflated to end of year values.

Interconnect Assets

The Commission has previously approved the inclusion of GasNet's $40.4 million investment in these assets in the PTS capital base.[65] Accordingly, this investment will be included in the capital base for the second access arrangement period.

Murray Valley pipeline

GasNet claims that the Commission incorrectly omitted its investment in the Murray Valley Pipeline from the initial capital base in its 1998 Final Decision.[66] However, it does not propose that this be corrected in the adjustment it proposes to the ICB. Instead it proposes to recognise it as capital expenditure occurring in 1998, which is what was forecast by GasNet's predecessor when it submitted the access arrangement for approval in 1997. The value of this construction is claimed to be $15.7 million[67] (although GasNet has $15.63 million in the table above); $15.7 is used in its modelling.

Southwest Pipeline

GasNet proposes to include the full cost of the Southwest Pipeline in its capital base through the economic feasibility test (section 8.16(b)(i) of the Code).[68] It states that the Victorian Government contributed $7.3 million of the $82.8 million total construction cost, giving a value for regulatory purposes of $75.5 million.

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65 ACCC, Interconnect Assets application Final Decision, 28 April 2000.

66 GasNet access arrangement information, 27 March 2002, p. 3 and submission, 27 March 2002, p. 29.

67 GasNet submission, 27 March 2002, pp. 4 and 29.

68 ibid., p. 35.

GasNet considers that this amount has been included in a speculative investment fund following the Commission's 29 June 2001 Final Decision under section 2.38(a)(ii) of the Code not to approve GasNet's prior application to roll in the cost of the Southwest Pipeline under the system-wide benefits test (section 8.16(b)(ii) of the Code).[69] It calculates that this amount will be $106.9 million as at 1 January 2003 after including an allowance for interest calculated on a compounded basis at the risk adjusted rate of return. However, after considering the prudent investment test (section 8.16(a) of the Code) GasNet proposes that the prudent amount to be attributed to the Southwest Pipeline is the original cost escalated to reflect inflation (that is, $85.0 million).

Consistent with GasNet's proposal to include the cost of the Southwest Pipeline through the economic feasibility test it proposes a stand alone (or incremental) tariff for use of those assets.

GasNet also submits that if the Commission concludes that the Southwest Pipeline does not pass the economic feasibility test, it does pass the system-wide benefits test.[70] GasNet identifies two sources of system-wide benefits for the Southwest Pipeline:

- enhanced system security and reliability; and
- enhanced competition.

GasNet further submits that if the Commission concludes that only a portion of the Southwest Pipeline passes each of the economic feasibility test and the system-wide benefits test, the Code allows each of those portions to be aggregated and included in the capital base.[71]

Finally, GasNet submits that if the Commission concludes that the Southwest Pipeline does not pass the economic feasibility test or the system-wide benefits test the Commission could treat the Southwest Pipeline as a new pipeline under section 8.12 of the Code with a separate access arrangement.

However, GasNet states that it does not propose that the Southwest Pipeline be subject to a separate access arrangement. Instead it notes its intention to merge the PTS and WTS access arrangements and suggests that the Southwest Pipeline could also be merged into the access arrangement taking into account its capital base which would have been determined by sections 8.12 and 8.13 of the Code.

Other projects

The Commission accepted the proposal by GasNet that forecast investment in the Brooklyn Loop be included in the calculation of reference tariffs for the first access arrangement period. This investment has not as yet been undertaken. GasNet proposes that the forecast cost of this investment be included in the calculation of reference tariffs for the second access arrangement period.

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69 ibid., schedule 3, p. 17.

70 ibid., schedule 3, p. 21.

71 ibid., schedule 3, p. 24.

4.2.4 Submissions

A number of parties commented on GasNet's proposals. For example, BHP Billiton submits that the Commission must test the capital expenditure allowed into the RAB and seek justification for any expenditure which exceeds the 'capex allowed'.[72]

Southwest Pipeline

A number of interested parties do not agree with GasNet's proposal for inclusion of the cost of the Southwest Pipeline in the PTS access arrangement. For example, EnergyAdvice identified the proposal as being a factor which it considered would lead to excessive tariffs and a price shock.[73]

Both BHP Billiton and ENERGEX consider that there is insufficient evidence to support GasNet's proposal. In particular, BHP Billiton requests that GasNet demonstrate that no cross subsidisation will occur. In addition, both parties raise concerns regarding the impact of the K factor adjustment. BHP Billiton notes that if the K factor is applied to the Southwest Pipeline then the tariffs will not retain the effect of stand-alone tariffs. Similarly, ENERGEX considers that the K factor mechanism may result in a transfer of 'redundant capital risk' from GasNet to its customers. As a result, neither BHP Billiton nor ENERGEX supports the inclusion of the Southwest Pipeline in the access arrangement.[74]

Origin supports roll-in of the Southwest Pipeline, but considers this is warranted under the system wide benefits test (rather than the economic feasibility test). Benefits identified by Origin are that Victorian customers are able to access the WUGS (and obtain system security for 1 in 20 winter peak demand days) and that upstream competition is facilitated by providing Otway Basin gas access to the Victorian market.[75]

Amcor and PaperlinX state that they have no objection to the Southwest Pipeline being included in the PTS access arrangement providing costs and revenues are 'clearly assessed and ring-fenced to ensure there is no cross-subsidisation'.[76] They comment:

> With the decision for Minerva Gas to flow to Adelaide via the recently committed SEAGas Pipeline combined with a review of the Saturn report it would appear that there is little likelihood of significant gas flows from the Otway Basin during the course of this new regulatory period.
>
> The development of the Minerva field has taken more than 5 years to bring into production. It would be surprising, therefore, if the developers of the Geographe and Thylacine fields could bring them into production during the course of the next access arrangement period. This would support the view that SWP is unlikely to deliver "new" gas into the Victorian market in the near term.
>
> Accordingly, our view is that SWP will be a greatly under-utilised resource in the regulatory period under review and the tariff structure would need to reflect this situation.[77]

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72 BHP Billiton submission, 21 June 2002, pp. 29 and 44.

73 EnergyAdvice submission, 30 May 2002, p. 8.

74 BHP Billiton submission, 17 May 2002, pp. 10-13; ENERGEX submission, 9 May 2002, p. 3.

75 Origin submission, 17 May 2002, p. 2.

76 Amcor and PaperlinX submission, 24 June 2002, p. 9.

Amcor and PaperlinX are strongly opposed to GasNet's proposal to allocate incremental costs to the Southwest Pipeline as they consider it would be contrary to the cost-reflective principles of the Code and would result in cross subsidisation. They consider that the Southwest Pipeline tariff structure should ensure that all costs associated with the Southwest Pipeline are 'fairly and appropriately allocated including opex, capex, depreciation, benefit sharing and K-factor carryover.'[78] They note the back-end loaded tariff proposed for the Southwest Pipeline and contend that any losses incurred should be fully identified and carried and only recouped from future usage of the Southwest Pipeline. In addition they are of the view that the claimed effective life of the Southwest Pipeline is significantly over-stated. Further, they consider that the tariff should recognise that gas flows will be bi-directional and that injection and withdrawal tariffs should apply at both ends of the Southwest Pipeline.[79]

ExxonMobil submitted a report by ACG that it commissioned on GasNet's proposal to include the cost of the Southwest Pipeline through the economic feasibility test and charge an incremental tariff on the Southwest Pipeline.[80] The report examines whether GasNet's average revenue yield approach is consistent with the intent of the economic feasibility test that assets included through that test should be paid for solely by users of those assets. The report demonstrates how the costs of the Southwest Pipeline could be passed on to other users of the PTS through the tariff control mechanism if it is not modified to quarantine revenue shortfalls on the Southwest Pipeline. The report recommends:

- a separate price control formula to apply to tariffs in respect of the Southwest Pipeline assets, and any K factor in the price control should be quarantined to future Southwest Pipeline tariffs;
- establishment of a redundant capital policy that requires the value associated with the Southwest Pipeline assets to be written down to the extent necessary to permit costs to be borne by Southwest Pipeline users; and
- fixed principles to ensure that the Southwest Pipeline is effectively quarantined in future periods.[81]

4.2.5 Commission's considerations

Interpretation of relevant Code provisions

The Code's economic feasibility test would be satisfied if the total PTS incremental revenue expected to be achieved from use of a new asset at least covers the costs associated with that asset. The Commission notes GasNet's contention that this test would be satisfied if only the gross incremental revenue expected to be generated from use of a new asset were to be considered (that is, without netting off any reduced

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77 ibid., p. 10.

78 ibid., p. 10.

79 ibid., p. 14. BHP Billiton also considers that injection and withdrawal tariffs should apply at both Iona and Lara: BHP Billiton submission, 21 June 2002, p. 13.

80 ACG, *Implementation of incremental pricing of the Southwest Pipeline*, June 2002 (ExxonMobil submission, 5 June 2002).

81 ibid., pp. 23-25.

revenue from use of other parts of the PTS which ensues from the use of the new asset). However, in interpreting this test the Commission considers that it must be satisfied that an investment would be viable without funding from the use of other parts of the PTS. In other words, the net increase in PTS revenues as a result of a new asset would need to at least match its cost. Accordingly, the Commission has assessed the cost of GasNet's new facilities investments against the associated net increase in revenues that would be reasonably expected to be generated on the PTS.

The Commission discussed the application of the Code's prudent investment test in its consideration of GasNet's earlier proposal to roll-in the cost of the Southwest Pipeline.[82] It concluded that this investment appeared to be prudent in a technical and engineering sense as it is sized appropriately to match the WUGS facility and its unit costs accord with relevant benchmarks. This is an important consideration when applying section 8.16(i) of the Code but does not in itself establish that an investment would 'achieve the lowest sustainable cost of delivering Services.'

For GasNet's access arrangement for the PTS, services are defined as those being provided by GasNet's transmission pipelines. GasNet's investment in the Southwest Pipeline increased the effective capacity of the PTS, allowing it to provide a greater quantity of the tariffed transmission service. More specifically, it provided additional capacity (and quantity of services) by means of a link between Lara and the Otway Basin.

The Commission noted that one of GasNet's predecessors calculated that similar additional system deliverability could have been achieved by instead looping the remainder of the Longford to Pakenham pipeline (including a minor upgrade of the Gooding compressor) for about two thirds of the cost of the Southwest Pipeline.[83] While this investment would have provided additional system deliverability it would not have provided a link with the Otway Basin and the WUGS facility. Therefore, whether GasNet's investment in the Southwest Pipeline would achieve the lowest sustainable cost of delivering services will depend on whether the relevant services are associated with additional system deliverability in general or specifically with the services provided by the Southwest Pipeline.

Southwest Pipeline

The Commission has previously considered a proposal by GasNet to include the Southwest Pipeline in the PTS capital base by applying the system-wide benefits test.[84] At that time the Commission concluded that the Southwest Pipeline does provide system-wide benefits in the form of system security and competition benefits but there was insufficient evidence to justify a commensurately higher tariff for all users. GasNet's access arrangement did not allow partial inclusion of an investment under this test. Consequently it recommended that GasNet reapply as part of the current review when there would be a longer operational history which would enable it to make a better informed assessment. GasNet could submit revisions to remove unnecessary constraints in its access arrangement. The Commission also expressed reservations

82 ACCC, Southwest Pipeline application Final Decision, 29 June 2001, pp. 31-37.

83 ibid., p. 30.

84 ibid.

about compliance of that proposal with reference tariff principles and the Code’s prudency requirements.

In assessing GasNet’s investment in the Southwest Pipeline under the prudent investment test it has come to the view that the relevant services include additional supply capacity and the connection with Iona. These services are discussed below. The Commission’s assessment is that GasNet’s proposed valuation of the Southwest Pipeline represents a prudent investment.

The Code’s economic feasibility test would be satisfied if incremental revenue on the PTS expected to be achieved from use of the Southwest Pipeline at least covered its costs. In interpreting this test the Commission must be satisfied that the Southwest Pipeline would be viable without funding from the use of other parts of the PTS. However, GasNet has not taken into account in its application the expected loss of revenue on the Longford to Pakenham pipeline compared to that which would have been achieved in the absence of the Southwest Pipeline. Accordingly, its estimate of the incremental revenue generated by the Southwest Pipeline is overstated. Adjustment for this factor results in a correspondingly higher reference tariff for the Southwest Pipeline.

The Commission has proposed an amendment to GasNet’s flow assumptions to recognise the likelihood that gas from the Yolla field will be injected into the PTS. These flows would be expected to displace potential flows on the Southwest Pipeline. Adjustment for this factor would result in a further increase in the reference tariff required for the Southwest Pipeline.

The economic feasibility test assessment relies crucially on the willingness of users to pay the stand-alone Southwest Pipeline tariff and the likely level of demand at that tariff (as the associated costs are known with considerable certainty). The Commission notes the doubts expressed by some parties about the sustainability of the demand forecasts at the tariff level proposed by GasNet. Once allowances are made for lower revenues on the Longford to Pakenham pipeline and demand displaced as a result of injections from the Yolla field, the level of the reference tariff required for the Southwest Pipeline increases substantially. The Commission does not consider that the Southwest Pipeline would be able to sustain the tariffs and flows that would be required to generate sufficient incremental revenue to cover its costs.

The Commission has considered GasNet’s argument that it should accept inclusion of the cost of the Southwest Pipeline under the economic feasibility test and not be concerned about these demand forecasts as the service provider would generally be expected to bear the costs of any consequent revenue shortfalls. However, as interested parties have noted, under GasNet’s first proposal, the cost of any demand shortfalls could potentially be shifted to customers using other parts of the PTS through the revised K factor mechanism. These parties are concerned that such a result would defeat the rationale for the Code’s economic feasibility test. They consider that this anomaly could be remedied through an amendment to the K factor adjustment such that any shortfalls in Southwest Pipeline revenues could be quarantined. The Commission notes that this anomaly would only be properly remedied if, at future revisions of the access arrangement, the Southwest Pipeline was quarantined from the cost allocation model as it has been in the current proposal. The Commission is also of the view that it would be inappropriate to include an asset in the asset base on the grounds that it would generate sufficient revenue to pay for itself if it were likely that the rationale for this test could be defeated through mechanisms which could permit its costs to be recovered from users of existing assets.

As the Commission is of the view that GasNet's investment in the Southwest Pipeline would not satisfy this first test proposed by GasNet, it has also considered GasNet's alternative proposals.

The Commission remains of the view that that this facility gives rise to some system-wide benefits in the form of system security benefits and competition benefits. However, it is not persuaded to change its view expressed in the June 2001 Southwest Pipeline Final Decision as there is inadequate evidence that system wide benefits would justify an increase in reference tariff for all users sufficient to recover the full costs of the investment.

The Commission proposes to approve the removal of current restrictions in GasNet's extensions and expansions policy that prevent inclusion of an investment under a combination of the section 8.16(b) tests (see section 11.3.5 of this Draft Decision). The Commission also considers that it may apply the provision of section 8.9 of the Code at the start of a new access arrangement period.

Consequently, the Commission considers that it can now accept roll in of the cost of an asset through a combination of the section 8.16(b) provisions. As noted, this was not possible at the time it considered GasNet's earlier application because of limitations imposed by GasNet's extensions and expansions policy.

The Commission considers it appropriate to assess the contribution of the Southwest Pipeline in terms of both the net additional revenue and the system wide benefits it would generate. It acknowledges that both contributions are difficult to quantify with any certainty.

The likely incremental revenue from the Southwest Pipeline is dependent on the tariffs which users will be willing to pay. GasNet has proposed that tariffs for the Southwest Pipeline will be based on a normalised revenue over 20 years and a normalised tariff over five years. This results in a higher initial tariff than if both were normalised over 20 years. A lower initial tariff would reduce the disincentive to using the Southwest Pipeline.

The Commission agrees with interested parties that the tariff proposed for the Southwest Pipeline appears to be unsustainable. It considers, however, that it is reasonable that charges for usage of the Southwest Pipeline would need to reflect the higher costs of providing services through this facility. At the same time, tariffs will need to be consistent with users' willingness to pay for use of the Southwest Pipeline.

The Commission considers that it is reasonable to assume that users will be willing to pay a premium of approximately 10 per cent to use the Southwest Pipeline (compared to the Longford to Pakenham pipeline) without prejudicing GasNet's demand forecasts (after allowance is made for projected gas flows from the Yolla field). It proposes to accept a tariff differential (of approximately an additional 10 per cent) for the purposes of the economic feasibility test. On this basis, it considers that a tariff of approximately

$2.00/GJ would be sustainable (though the exact amount will depend on the tariff applicable for the Longford to Pakenham line).

A Southwest Pipeline tariff of approximately $2.00/GJ implies that only about half its cost would be able to be recovered under the economic feasibility test. It is the Commission's view that the system wide benefits available from the Southwest Pipeline are broadly commensurate with those provided by the Interconnect Assets (which were assessed as being adequate to justify $40.4 million of costs in 2000). Together, these contributions may cover the full costs proposed by GasNet for its investment in the Southwest Pipeline.

Accordingly, the Commission proposes to accept roll in under a combination of the Code's economic feasibility test and system-wide benefits test. Consistent with its views regarding the sustainability of charges on the Southwest Pipeline, it proposes that:

- tariffs for the Southwest Pipeline should be calculated on the basis of full levelisation over 20 years; and
- tariffs for the Southwest Pipeline should be approximately 10 per cent higher than those on the Longford to Pakenham Pipeline.

Proposed amendment 7

GasNet must amend its revised access arrangement to include tariffs for the Southwest Pipeline which are approximately 10 per cent higher than those on the Longford to Pakenham Pipeline. In addition, the tariffs for the Southwest Pipeline are to be calculated on the basis of full levelisation over 20 years.

The Commission notes that the Southwest Pipeline is not a new pipeline for the purposes of the Code and cannot be treated as one.

The Commission's assessment of proposals by interested parties to quarantine GasNet's investment in the Southwest Pipeline is provided in its consideration of the K factor adjustment in section 6.2.2.

Interconnect Assets

As the Commission has previously approved the roll-in of GasNet's investment in these assets[85], GasNet's investment will be reflected in the revised capital base as at 31 December 2002.

Murray Valley Pipeline

GasNet offers no argument in its submission as to why it considers that this expenditure should be included in the PTS capital base without consideration of the tests in section 8.16 of the Code. GasNet's approach appears to rely on the wording of section 8.9(b) which refers to inclusion of new facilities investment in the immediately preceding access arrangement period. GasNet appears to contend that the Commission should

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85 ACCC, Interconnect Assets application Final Decision, 28 April 2000, p. 60.

now include this investment in the value of the initial capital base and that it be rolled forward pursuant to section 8.9(a). The Commission acknowledges that the Murray Valley Pipeline commenced operation prior to the PTS access arrangement coming into effect in March 1999. However, the provisions of the Code do not allow it the discretion to redetermine the value of the initial capital base. Accordingly, this investment cannot be rolled forward under section 8.9(a).

The Commission is cognisant of the objective set out in section 8.1(a) that a service provider should be allowed the opportunity to recover the efficient costs of an investment. It considers that this fundamental objective would not be achieved if the investment was precluded from inclusion in the PTS asset base.

The Commission has requested from GasNet information which would support its inclusion. GasNet has supplied information but it was received by the Commission too late for it to be assessed and included in this Draft Decision. The information is available on the Commission's web site and the Commission requests that interested parties address this issue in their submissions to this Draft Decision. The Commission's analysis will appear in the Final Decision.

The revised RAB developed by the Commission in Table 4.3 above assumes that the whole of the $15.7 will be included in the capital base. If some or all of the Murray Valley pipeline does not pass the section 8.16 tests then the RAB will be lower.

Other projects

Apart from the capital expenditure on the Murray Valley Pipeline, the Interconnect Assets and the Southwest Pipeline discussed above, other capital expenditure during 1998-2002 was minor in nature, totalling approximately $11 million. The majority was in relation to compressor automation and restaging.

GasNet has argued that the automation of the Gooding and Brooklyn compressors ($7 million) was necessary to maintain the safety and integrity of the system.[86] Submissions did not address this issue. The Commission has no evidence to suggest that this project was not prudent. Consequently it proposes not to object to the inclusion of these costs in the capital base.

GasNet argues that the Brooklyn compressor restaging and cooler upgrade ($1.8 million) was essential to provide the higher flows and pressures for summer injections of gas into the WUGS.[87] It does not nominate which of the section 8.16 tests this project meets. It could be argued that as it facilitates the use of the WUGS that the question is whether this project passes the economic feasibility test and that the test would involve assessing the increased revenues from the use of the WUGS. Thus, this expenditure would need to be taken into account in the analysis of the Southwest Pipeline. Similar to the assessment of the Southwest Pipeline, it could also be argued that facilitating the use of the WUGS provides a system wide benefit. Given that part of the Southwest Pipeline passes the system wide benefits test, and the relatively small size of this expenditure, the Commission proposes to add the Brooklyn compressor

[86] GasNet submission, 27 March 2002, p. 42.

[87] ibid., p. 42.

restaging and cooler upgrade to the RAB under the system wide benefits test. The Commission has no evidence to suggest that this expenditure is not prudent.

The remaining $3 million of capital expenditure was mainly for maintenance purposes. GasNet makes no comment on its inclusion in the RAB nor is this expenditure addressed in submissions from interested parties. The Commission has no evidence to suggest that this expenditure was not prudent and considers maintenance of the system to be significantly linked to the safety of the system. Consequently, the Commission proposes to accept the inclusion of this capital expenditure in the RAB under section 8.16(b)(iii) of the Code.

4.3 Redundant assets

4.3.1 Code requirements

Section 8.27 of the Code allows a reference tariff policy to include (and the regulator may require that it include) a mechanism that will remove redundant capital from the capital base at the start of a new access arrangement period. The adjustment is to:

- ensure that assets which cease to contribute to the delivery of services are not included in the capital base; and
- share the costs associated with a decline in volumes between the service provider and users.

Before approving a redundant capital policy the regulator must consider the uncertainty the mechanism would cause and the impact this would have on the service provider, users and prospective users.

Section 8.28 of the Code provides that where redundant assets subsequently contribute to the delivery of services the assets may then be treated as new facilities investment and included in the capital base.

While the Code permits a reference tariff policy to include a mechanism to subtract redundant capital from the capital base, it also allows (under section 8.29) for other mechanisms that have the same effect on reference tariffs while not reducing the capital base.

4.3.2 Current access arrangement provisions

Clause 5.3.5 of the PTS and the WTS access arrangements allow the Commission to review and, if necessary, adjust the relevant capital base for wholly or partially redundant assets. This is to occur at the start of the subsequent access arrangement period.

4.3.3 GasNet proposal

GasNet has proposed the removal of the cost of the North Paaratte Odorant Station, and certain land and vehicles from its capital base for the forthcoming access arrangement period on the basis that they are fully redundant.[88]

The North Paaratte Odorant Station ceased operation 2001 and no longer makes any contribution to the pipeline. The written down regulatory value of $0.2 million has been deducted from the capital base.

Since 1998 GasNet has disposed of a number of assets such as land and vehicles. For this reason, a total of $1.8 million should be removed from the capital base.[89]

GasNet has not identified any partially redundant assets.

4.3.4 Submissions

No submissions have been received concerning assets that may now be fully or partly redundant.

4.3.5 Commission's considerations

The Commission has assessed the items listed by GasNet as redundant or disposed of. While the Commission has raised with GasNet some concerns over the calculation of the values associated with these items, these mainly relate to timing and modelling details and do not bring into question the fundamental valuation of these items. The revised figures are contained in Table 4.2 in section 4.15 above. These revised figures will need to be reduced by the exclusion of two assets listed by GasNet as redundant which are part of the assets GasNet has sought to be included in the revised ICB. As the Commission proposes not to allow these to be included in the ICB, they should also be excluded them from the sum of redundant assets. Their value is small and the total of redundant assets (rounded to the nearest tenth of a million dollars) remains the same as proposed by GasNet.

The Commission is unaware of any other assets which should be considered redundant, or which were disposed of during the period.

88 ibid., p. 19.

89 ibid., p. 36.

5. Rate of return

5.1 Code requirements

When setting revenue benchmarks, sections 8.30 and 8.31 of the Code require the implied rate of return on the regulatory value of the business' assets to be determined according to the following principles:

> The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).
>
> By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well-accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

The first provision requires the implied return factored into the assessment of the reference tariffs for a service provider's regulated activities to reflect the opportunity cost of capital associated with those activities. This concept is discussed below.

The second provision provides additional guidance on how to estimate the cost of capital associated with the business' regulated activities. It specifically allows for returns to be determined on the basis of a well-accepted financial model, such as the CAPM.[90] This model is discussed further below. It also encourages the use of benchmarks for such matters as financing arrangements – which is discussed further in section 5.4 below.

Section 8.1 of the Code also provides relevant guidance for determining the rate of return. A central theme of all but one of these objectives is the pursuit of economic efficiency. Two factors necessary for economic efficiency are: for investors to expect to receive a stream of income over the life of an asset that is at least equal to the cost of an asset; and that average prices to customers be as low as possible. These factors can be reconciled by setting price controls based upon an unbiased estimate of the efficient cost of providing the service. While this principle applies across all of the assumptions factored into the price controls, it implies that the return should reflect an unbiased estimate of the cost of capital.

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90 An explanation of the cost of equity capital and the role of the CAPM is outlined in ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002.

5.2 Current access arrangement provisions

In its 1998 Final Decision of the access arrangements for regulation of GasNet's transmission pipelines the Commission approved a WACC calculated from the cost of equity (r_e) and the assessed cost of borrowed funds (r_d):

$$WACC = r_e \times \frac{E}{D+E} + r_d \times \frac{D}{D+E}$$

where E/(D+E) and D/(D+E) are respectively the shares of equity and debt in the financing structure of the asset.

The return on equity (r_e) was calculated using the CAPM and the return on debt (r_d) calculated as the risk free rate plus a debt margin thought relevant to raising borrowed funds at the time of the decision. It is notable that the return on equity indicated by CAPM is a post-tax rate of return and the WACC formula noted here is sometimes referred to as the 'vanilla' WACC. It is the return the company would require to meet its cost of capital if it was not required to pay company tax. Therefore, an additional element of return is required to cover tax liabilities that the company may face in order to have an expectation of achieving the benchmark return implied by the WACC formula.

In 1998, the additional compensation for tax was provided for by the application of a pre-tax WACC. That is, it was a modified WACC formula which effectively gave a WACC premium (sometimes referred to as the tax wedge) to cover expected tax costs. The important feature of the tax component of revenues is that it was not intended to cover current taxes (which may be very low) but rather cover tax costs anticipated in an NPV sense over the life of the assets.

The applicant at the time proposed a formula for calculating the tax wedge recognising the operation of the tax imputation system in Australia. The formula, developed by Professor Bob Officer related to an annuity and did not capture other features of the tax system in Australia (such as accelerated depreciation) and inflation effects which significantly influence the timing and impact of tax payments on the company and its investors. Hence, the Commission applies a cash flow approach to make a more realistic assessment of tax liabilities for the purpose of determining what value of the pre-tax WACC may be appropriate to establish the return on capital component of the revenue requirement. In the 1998 Final Decision the vanilla WACC was estimated to be 6.94 per cent and the real tax wedge set at 0.81 per cent to give a pre-tax real WACC of 7.75 per cent, which was commensurate with a return on equity of 13.2 per cent.

While the Commission accepted the application of a pre-tax WACC on that occasion, it noted in its decision that the approach was fundamentally flawed. First, it required long term forecasts of Australian tax legislation which are difficult to forecast and may prove to be incorrect. Second, tax liabilities are expected to increase significantly in later years while compensation for tax has been provided substantially in advance. This effect, called the S-bend issue in the earlier decision, was seen as potentially creating a tension between the regulatory framework and the cash flow needs of the company to meet its tax liabilities when they occur.

To overcome these problems the Commission made it quite clear in that final decision that it intended to assess all future access arrangements on a post-tax basis. That is, there would be no anticipatory compensation for tax but rather tax would be assessed on an ‘as you go basis’ and the regulatory return would be based on the vanilla WACC. In such a framework the financial circumstances of the company, as reflected in regulatory accounts, would be used to estimate a benchmark tax liability relevant to the regulatory period under consideration. This tax liability estimate would be compensated for as explicit cash flows in the regulatory revenue calculation. The Commission has used this approach in all subsequent regulatory assessments for gas pipelines. Where taxes were thought to create a jump in revenue requirements and hence tariffs, the Commission has proposed modification of the depreciation profile to create a revenue path similar to that which would emerge in a pre-tax framework. In this approach, the pre-payments of tax compensation may be interpreted as a return of capital which is reversed when tax becomes payable. Further details of this approach may be found in the Commission’s *Post-tax Revenue Handbook*.[91]

One factor impacting on a estimate of the tax liability is the taxation system’s provision for accelerated depreciation. This creates a tax benefit, that is, it defers tax liabilities, for many years. The 1998 Final Decision noted that, as a result of this provision, the service provider would be expected to pay little or no tax for the first years of operation.[92]

5.3 GasNet proposal

GasNet has proposed a WACC formulated in exactly the same way as in the first access arrangement period. However, it has proposed updated values for a number of the CAPM and WACC parameters. The Code requires:

> ... a return which is commensurate with the prevailing conditions in the market for funds and the risks involved in delivering the Reference Service[93]

Therefore, updating such parameters is necessary if the cost of capital is to remain appropriate under the financial conditions expected during the forthcoming access arrangement period.

In addition to the return on capital embodied in the application of the WACC, GasNet has proposed a number of cash flow adjustments to reflect specific asymmetric risks that are not addressed by the CAPM.

The CAPM and WACC parameter values being proposed by GasNet are detailed in the following sections and compared with the values approved in the 1998 Final Decision. The rationale given by GasNet for its preferred parameter values and the Commission’s assessment of risk claims are also discussed.

91 ACCC, *Post tax revenue handbook*, 2001.

92 ACCC, 1998 Final Decision, pp. 169-174.

93 Introduction to section 8 of the Code.

Notably, GasNet has proposed to continue with a pre-tax approach despite comments in the 1998 Final Decision drawing attention to the fundamental difficulties of that framework. To convert the vanilla WACC into pre-tax form GasNet has estimated a tax wedge by applying a simplified financial model of the company's cash flows rather than relying on the more detailed model used to establish actual reference tariffs. The simplified model used is one of the Commission's own illustrative models published in conjunction with the *Post-tax Revenue Handbook*. The model in question uses a normalisation procedure (adjusting the depreciation profile) to generate revenues in a post-tax framework which are smooth and unaffected by tax payments when they become due. The 'tax wedge' is deduced simply by noting the increment of revenues above what they would have been if no company tax was imposed over the life of the business. In making the calculations GasNet made two key explicit assumptions:

- the value of the regulatory assets was written down for tax purposes relative to their regulatory value; and
- tax depreciation on the written down value was straight line over the remaining economic life of the assets (that is available tax concessions were assumed not to apply).

Once GasNet established the pre-tax WACC using this approach, it is utilised in its detailed asset and cost allocation model to derive reference tariffs and forecast revenue requirements.

GasNet submits that the Commission should not revisit its approval of the current tariffs and adjust the capital base for amounts related to the pre-payment of taxation liabilities. It also considers that the benefits of accelerated depreciation for tax purposes should be retained by GasNet because it would:

- be consistent with the government policy objectives;
- reflect the behaviour of a competitive market; and
- be consistent with the Commission's 1998 Victorian decision.[94]

GasNet included a report it commissioned by Network Economics Consulting Group (NECG) in support of this position.[95] NECG provided 'selected quotes' relating to the policy objective of accelerated depreciation of providing an incentive to investment in certain assets.[96] NECG notes that as a consequence of the Government's decision to implement aspects of the Ralph Committee recommendations, the provision for accelerated depreciation has been removed for assets acquired or commenced to be constructed from 21 September 1999. NECG considers that the 'grand fathering' of accelerated depreciation provisions for assets constructed or acquired before that date

94 GasNet submission, 27 March 2002, p. 60.

95 ibid., annexure 3.

96 ibid., annexure 3, pp. 6-9.

demonstrates a recognition by the Commonwealth Government that accelerated depreciation benefits represents a property right that is vested in infrastructure owners.[97]

NECG considers that the Commission's suggested approach of adjusting the capital base for the value of accumulated deferred company tax liabilities would transfer 'the financial benefit of accelerated depreciation from the investor to its customers'.[98]

NECG concluded:

> If the ACCC persists with this initiative, so far not applied to GPU GasNet's Principal Transmission System, but advocated in the context of the Draft Decision on the MSP Access Arrangements, the investment incentives intended through accelerated depreciation will be entirely negated retrospectively.
>
> The provision of the subsidy occurred in an environment where pipelines were in a position to extract virtually all of the benefit of the subsidy. It is these benefits that encouraged the investment in the pipeline in the first place. The approach proposed by the ACCC will offset the incentives that accelerated depreciation was intended to impart. The result is even inconsistent with the outcomes one would expect from a competitive or contestable market.[99]

5.4 Commission methodology and approach

Pre-tax and post-tax

As noted earlier, the Commission has strongly signalled its preference for a post-tax approach in calculating the cost of capital or WACC. Within this framework return on capital invested is covered by applying the vanilla WACC, which would be the rate of return on assets required if no company tax was payable. There is no requirement to calculate a tax wedge. Instead, tax liabilities are compensated for explicitly by an allowance in cash flows to cover anticipated taxes when they are due.

The alternative approach of applying a simple transformation formula to derive a long term estimate of likely tax liabilities is dubious. First, the assumptions regarding the tax system in the use of the transformation approach are far from obvious, are certainly not transparent and do not promote an informed debate. Different regulators have applied several incompatible variations of the transformation approach but none give outcomes consistent with what might be viewed as reasonable cash-flow simulation of tax liabilities. For these reasons the Commission has avoided any of the transformation approaches as a basis for assessing what compensation for tax needs to be added to post-tax revenue estimates in order to give an expectation of the CAPM based benchmark return being achieved.

The GasNet proposal is a pre-tax framework and retains all the problems of that approach. Its partial use of a post-tax revenue model developed by the Commission does not alter this fact. Indeed, the assumptions adopted by GasNet in using the model serve to illustrate some of the problems of the pre-tax approach:

[97] ibid., annexure 3, p. 9.

[98] ibid., annexure 3, p. 10.

[99] ibid., annexure 3, p. 17.

- a realistic assessment of tax is prevented by assuming away tax concessions which are clearly available to the firm; and

- there is a need to make long term forecasts of future tax legislation, which increases uncertainty for the firm in how it will meet its future tax liabilities while retaining the desired post-tax return.

Perhaps the issue of greatest concern with the GasNet proposal is that, in determining the tax wedge designed to cover future tax liabilities, it explicitly requested that payments already received designed to compensate for future taxes should be ignored. This is directly related to the S-bend issue noted in the 1998 Final Decision. This means that while approximately $16 million was included in the benchmark revenue in the first access arrangement period, GasNet is asking that the benchmark revenues from 2003 onwards reflect compensation for the full amount that GasNet needs to pay its tax liabilities. This is a violation of the regulatory compact that requires that the company not seek to be compensated for expected tax liabilities more than once.

GasNet in its modelling does not provide an accurate representation of its tax position for the purpose of establishing reasonable estimates of benchmark tax liabilities. Specifically, the proposal ignores:

- accelerated depreciation tax concessions available on its existing regulated assets; and

- its initial tax position at the start of the new regulatory period. The tax position, including any carried forward tax loss is important in making a realistic assessment of future tax liabilities for which compensation is required.

To overcome the problems with the pre-tax approach and promote transparency, and consistency the Commission requires a move to a post-tax approach. In this approach the vanilla WACC provides an appropriate guide for the return required on assets provided there is an explicit compensation for tax in cash flows.

The asset model provided by GasNet did not lend itself to modification to accommodate the post-tax approach. Instead the Commission has adapted the model published with the *Post-tax Revenue Handbook* to capture the main structural features of the GasNet model.[100] To avoid other complexities and promote transparency the Commission proposes not to a change to depreciation profiles to effect a normalisation of revenues over the life of the asset.

The Commission shares the view of GasNet that the CAPM and WACC parameters needed to estimate the (vanilla) WACC will require updating to reflect current financial conditions as required by the Code. However, many of the changes proposed by GasNet reflect a changed perception of risks faced by the service provider. The Commission does not agree with many of these changes. Individual parameters are discussed in detail in the following sections along with the Commission's response to

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[100] These modifications picked up key features of the full asset model matching the depreciation and roll forward of assets. However, for tax depreciation it was assumed that all assets were treated as if they were gas pipelines. This simplifying assumption is not expected to be of material significance.

the proposals. To the extent that financial circumstances continue to change many of the parameters must remain only tentative until the Commission's Final Decision.

Establishing benchmark tax liabilities

A key objective in determining the allowance for taxation is that it reflect an unbiased estimate of tax liabilities for an efficient company. Most of the inputs required to deduce likely tax liabilities for the regulated operations are readily available from the regulatory framework:

- assessable revenue – assumed to be the revenue benchmark;
- operating expenditure – assumed to be the operating expenditure benchmark;
- capital expenditure – taken to be historical and forecast capital expenditure; and
- interest expenses – taken as the nominal interest payments implied by the benchmark financing arrangements (gearing, in particular).

The remaining information required relates to the tax position of the regulated business at the start of the next access arrangement period and information to determine depreciation allowances for taxation purposes. These are the two items it was noted above that GasNet did not supply with its model.

The tax position is essentially defined by the carried forward tax loss which can be offset against future income to diminish future tax liabilities. Tax depreciation which is a recognised cost by the Australian Taxation Office and is available to reduce assessable income depends on:

- the opening value of the assets for tax purposes;
- the depreciation rates and method (straight line or diminishing value) assumed for each asset class; and
- the proportion of capital expenditures that fall into each class.

Opening tax value of assets and carried forward tax loss

To establish the firm's current tax position there is a need to know what provisions are available to it to reduce (or defer) tax liabilities. An important element of this is the starting written down value of the assets for tax depreciation as this determines the amount of remaining tax depreciation that can be assigned to reduce assessed income and hence the associated tax liability. When the tax depreciation results in assessable income being negative so that no tax is payable, the excess usage of depreciation applied is not lost but is carried forward as a tax loss which may be assigned to reduce positive income and tax liabilities in future periods. Therefore, the remaining available value of assets for tax depreciation and the carried forward tax loss together define the starting tax position of the firm in any period and have a significant bearing on tax payments that will be due in the period.

In order to establish GasNet's tax position going into the new access arrangement period the Commission has re-modelled the regulated cash flows over the initial access arrangement period on the assumption that no pre-tax compensation was received. Since that period represented the commencement of regulated operations it was assumed that there was no prior accumulated tax loss (or profit) and the initial value of the assets for tax purposes was equal to the ICB established in 1998 at the commencement of the first access arrangement period. While this assumption represents a windfall gain to GasNet, the Commission is inclined to over look this pre payment of tax to facilitate the move to the post tax approach. Revenue requirements for the second access arrangement period were calculated applying the standard post-tax framework. The recalculation of revenues for the previous period was necessary to capture the impact of significant enhancements of the access arrangements during the period (for example, the inclusion of the Interconnect Assets) and to establish the benchmark tax position at the commencement of the next regulatory period. The result obtained was that the benchmark company accumulated a forecast carried forward tax loss of $145 million and a forecast written down value of the assets for tax purposes of $208 million at the end of 2002. These forecasts have a significant bearing on how far into the future taxes will actually become payable.

Depreciation rates

GasNet has proposed that the tax assessment ignore the availability of accelerated depreciation but not the imputation system, arguing that the regulatory framework should not remove an industry benefit intended by the government. This view fails to appreciate that the regulatory framework provides a benchmark return required by investors and investors benefit from accelerated depreciation in exactly the same way as they would if the company was not regulated.

In terms of asset classes and depreciation rates applicable to each, a detailed assessment was not made for the purpose of this Draft Decision. Instead, it was assumed all tax depreciable assets could be classified as pipelines for depreciation purposes. This is still a good approximation since pipelines account for the bulk of asset value and capital expenditures. Some assets may be written off faster but these will tend to be offset by real estate assets which may not be depreciated at all. This approach may be maintained for future regulatory decisions. However, if GasNet wishes to link tax depreciation to specific assets it will need to provide the appropriate asset register roll forward for tax purposes in a similar way to which it does for regulatory asset values.

The Commission's modelling has taken into account that the opening asset values of assets in the ICB plus additions to the asset base until 20 September 1999 (prior to business tax reform) are subject to straight line depreciation at the rate of 13 per cent per annum where as from 21 September 1999 straight line depreciation at the rate of 5 per cent per annum is applicable on new capital expenditures.

The taxpayer may also choose to apply diminishing value tax depreciation at a rate 50 per cent higher than the straight line rate. For a stand-alone corporate operation this seems to provide little additional deferment of tax payments. Therefore, for simplicity, the Commission has assumed straight line depreciation to estimate the tax liability benchmark.

5.5 Determination of the return on equity

5.5.1 Interest rates and inflation

Interest rates

The risk-free rate (r_f) is an important parameter which is used to determine both the cost of debt and the cost of equity. The risk-free rate measures the return an investor would derive from an asset with certainty of return being achieved. Most regulators, including the Commission, have approximated the risk free rate by the yield to maturity on government bonds, as the government is in a position to honour all interest and debt repayments.

The Commission adopted a five year term when estimating the risk-free rate at the start of the first access arrangement period for the GasNet access arrangements. A 40 day moving average of this five year rate was taken to minimise the impact of short term spurious movements in relevant interest rates.

GasNet proposes maintaining the approach of equating the risk-free rate with the return on Commonwealth Government Bonds. GasNet submits that 10 year bond rates should be used as the basis of the risk-free rate. It argues that 10 year real rates are preferable to five year rates (which equate with the length of the access arrangement period) as 10 year rates match the long-term nature of the investment and are less volatile than five year rates.

BHP Billiton states that the Commission should apply the five year bond rate instead of the 10 year bond rate. It argues that this is because the five year bond rate has more justification than using the 10 year bond rate, as it matches the regulatory period. BHP Billiton adds that GasNet prefers the longer term rate as it leads to a higher WACC.[101] Amcor and PaperlinX concur on the appropriate maturity period, stating that:

> The ACCC approach to the risk free rate (5 year bonds) is correct as it matches the forward looking period of the access arrangement and reflects the expected risk profile of the period under review.[102]

The Commission sought advice from Dr Martin Lally on this and several other risk free rate related issues.[103] Lally's paper assesses the arguments proposed for not using the five year bond rate determining that these arguments are largely unfounded. He concludes that the five year bond rate is the appropriate bond term to consider when the regulatory period is five years.

In relation to the measurement of the risk-free rate, GasNet proposes that a 40 day averaging period should be maintained, and that the appropriate averaging period and dates to be used should be agreed in advance of the Final Decision. GasNet requests that this period be determined on a confidential basis between GasNet and the Commission, and only be disclosed to the market after the event so as to prevent any arbitrage opportunities arising.

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[101] BHP Billiton submission, 21 June 2002 pp. 33-34.

[102] Amcor and PaperlinX submission 24 June 2002, p. 23.

[103] M Lally, *Determining the risk free rate for regulated companies,* a paper for the ACCC, July 2002.

Under section 8.30 of the Code, the Commission is required to set a rate of return 'commensurate with prevailing conditions in the market for funds.' This implies that information used in deriving the rate of return should be as up to date as possible and reflect the circumstances (economic conditions) of the regulatory framework.

In accordance with these requirements, the Commission considers that it is appropriate to maintain the use of interest rates that correspond with the length of the access arrangement period. Thus, for GasNet, which is seeking a five year access arrangement period, the yield on bonds with a term to maturity of five years should be used. The adoption of this methodology should ensure that the expected regulatory return over the sequence of reviews will match the initial risk-free rate expected by the market over the life of the asset. This approach should provide GasNet with the right signals for investment at all times. Further, the Commission has maintained the use of a 40 day moving average of rates to smooth out any short-term volatility that may occur in bond markets.[104]

As noted above, GasNet has proposed that the Commission inform it of the averaging period to be used to measure the risk-free rate a period in advance of the Final Decision. GasNet has requested this information so that it can organise its market hedging activities. The Commission is aware of no reason why it should not provide the information as requested. The Commission proposes to advise GasNet of the relevant period no later than four weeks before the expected release of its Final Decision.

In accordance with the above approach, the results for this Draft Decision are a nominal risk-free rate of 5.72 per cent and an interpolated real risk-free rate of 3.14 per cent.[105] These rates are only indicative as they will be recalculated prior to the Final Decision.

Inflation

GasNet notes that regulators have been determining the rate of inflation with reference to bonds that are used to calculate the risk free interest rate. With a view to adopting the same approach, GasNet proposes to use 10 year bonds to determine the expected rate of inflation. However, for the purposes of the proposed revised access arrangement GasNet has used an inflation rate of 2.5 per cent.[106]

As discussed in detail in previous Commission decisions, the Commission's approach to determining inflation for regulatory purposes is to use bond rates with a term equivalent to the regulatory period. Accordingly, the expected inflation rate applicable for GasNet's forthcoming access arrangement period, and derived from the relevant bonds rates noted above, via the Fisher equation, is currently 2.51 per cent. Along with the risk free rate, this will be recalculated prior to the Final Decision.

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[104] The Commission is currently in the process of reviewing its methodology for determining the risk-free rate.

[105] Calculated 30 July 2002.

[106] GasNet submission, 27 March 2002, p. 54.

5.5.2 Debt margin and the cost of debt

A debt margin of 120 basis points was adopted by the Commission in its 1998 Final Decision.[107] The 120 point margin was added to the yield on a five year nominal risk free rate of 6.0 per cent to obtain a nominal cost of debt figure of 7.2 per cent for use in the WACC estimation.

In its proposed access arrangement revisions, GasNet suggests that 120 basis points represents an appropriate debt margin for a company with GasNet's characteristics, and that the cost of debt should be determined on the basis of this margin.

As noted in the *Draft Statement of Principles for the Regulation of Transmission Revenues* (DRP),[108] the Commission considers it appropriate to abstract from the actual cost of debt facing the service provider as the actual cost of debt may not reflect efficient finance sourcing. Thus, the Commission is of the view that the cost of debt should be determined through reference to a benchmark debt margin which is consistent with the other benchmarks adopted.

The calculation of the benchmark debt margin is essentially an empirical matter. Specifically, the calculation of the debt margin requires the Commission to consider two distinct empirical questions: the appropriate benchmark credit rating of the service provider; and the market observed debt margin associated with that benchmark rating.

With regard to the credit rating of a service provider, the Commission considers it appropriate to estimate a benchmark rather than use an actual credit rating given that the creditworthiness of the entity is in part under managerial control and the use of a benchmark is consistent with other assumptions. The Commission is of the view that relevant Australian gas transmission and distribution companies should be used as the basis of a benchmark. It is important for consistency that these companies are stand-alone entities and are void of government ownership. Further, it is important that the gearing ratio of the entities used to calculate the debt margin are not significantly different from the gearing assumptions used to determine the WACC.

Table 5.1 below sets out the long-term credit rating for four Australian transmission and distribution gas companies that meet the stand-alone entity criteria and have been assigned a credit rating from ratings agency Standard and Poors.[109]

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107 The current access arrangement provisions implicitly assume the inclusion of bank costs in the debt margin for the purposes of the calculation of the debt beta.

108 ACCC, *Draft statement of principles for the regulation of transmission revenues*, May 1999, p. 82.

109 A stand-alone entity may be defined as an entity that does not have a parent company (a company that holds the majority of voting stock). With regard to the companies used to estimate the benchmark credit rating, approximately 18 per cent of Envestra Ltd is owned by Cheng Kong Infrastructure Holdings (Malaysia) Ltd and another 18 per cent is owned by Origin Energy Ltd (source: http://www.envestra.com.au). Further, 45 per cent of AlintaGas is owned by WA Gas Holdings Pty Ltd, which is jointly owned by Aquila Inc and United Energy Limited (source: http://www.alintagas.com.au).

Table 5.1: Credit rating associated with stand-alone energy companies

Company	Long-term rating
GasNet Australia	BBB
Envestra Ltd	BBB
AlintaGas	BBB
AGL	A

Source: Standard and Poors website (www.standardandpoors.com.au), June 2002.

On the basis of this data, the average credit rating of these entities approximates BBB+.[110] This data is also corroborated by analysis undertaken by financial market experts. Accordingly, the Commission considers that a BBB+ credit rating represents an appropriate proxy credit rating for the benchmark company.[111]

Having established a proxy credit rating, a benchmark debt margin can be determined. Debt is raised by asset owners either through bank markets or through the private and public capital markets. Debt requirements have primarily been met by the bank market for projects involving construction in Australia.[112] Evidence suggests that for energy infrastructure, re-financing arrangements have also largely been met by institutional lenders, although capital markets have played a role (for example, the November 2000 and March 2002 debt issues by GasNet).[113]

The Commission understands that the interest margin associated with bank issued debt is generally lower than capital market interest margins. However, information on the debt margin associated with bank issued debt is generally not widely available. The Commission therefore considers that it is reasonable to use capital market data as the basis of the benchmark debt margin calculation, even though it may provide a benchmark which is biased in favour of the service provider.

Table 5.2 below summarises the spreads above the Commonwealth government bond rate for publicly traded BBB+ corporate bonds as of 5 July 2002. This spread represents the debt margin above government bonds in basis point terms. As the data illustrate, bonds with maturity in approximately five years (March 2007 and October 2007) are currently exhibiting a spread of between 125 and 129 basis points above government bonds.

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110 Recent evidence suggests that with the exception of Envestra, the gearing ratio of the companies used to calculate the benchmark are within a 10 per cent range of the 60:40 benchmark rate (Envestra has a gearing ratio of about 80 per cent (www.envestra.com.au)).

111 Some of these companies have non-regulated activities, which all else being equal, should lower the overall credit rating. Therefore, the rating for a 100 per cent regulated benchmark company would generally be higher than the benchmark determined above.

112 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines*, Report for the ACCC, May 2002. p. 7.

113 ibid., p. 22.

Table 5.2: Australian corporate bonds issued

BBB+ company	Maturity	Spread above government bonds[a]
Coles	September 2003	74.5
Ford	August 2003	129.5
Qantas	October 2003	84.5
Ford	March 2004	137.0
DOT	April 2004	78.0
DDT	September 2004	88.0
Southcorp	August 2006	109.0
Origin Energy	March 2007	124.5
Qantas	October 2007	128.5
Southcorp	March 2010	139.5

Source: ABN Amro, 5 July 2002.
Note: (a) Benchmark spread above Commonwealth Government Securities with matching maturity.

This data is supported by information from the Commonwealth Bank of Australia published by Standard and Poors. According to the analysis, at the end of June 2002 the spread over the government bond yields for BBB+ corporate bonds with a maturity of five years was 132 basis points.[114]

It is therefore reasonable to suggest that the debt margin for BBB+ bonds with maturity of five years is likely to be in the range of 125-132 basis points. In light of this evidence, the Commission considers that the proposal put forward by GasNet for a debt margin of 120 basis points may underestimate the current market debt margin associated with a benchmark regulated transmission or distribution entity. The Commission therefore proposes adopting a debt margin of 130 basis points for GasNet, and will continue to monitor capital markets for further evidence that the debt margin for a benchmark BBB+ entity is increasing or decreasing. The Commission proposes adjusting this figure for the Final Decision to reflect the latest available data at that time.

The Commission considers it appropriate to add an 8 basis points margin for prudent debt raising costs to the debt margin facing GasNet (see section 6.2.1 of this Draft Decision). Thus, the effective debt margin used in the calculation of the WACC for GasNet is 138 basis points. The Commission notes that the ESC has recently proposed a recovery of 140 basis points for the Victorian gas distribution companies.[115]

5.5.3 Market risk premium

The rate of return determined for the PTS and WTS in 1998 included a market risk premium estimate of 6.0 per cent.

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[114] CBASpectrum data cited at www.standardandpoors.com.au

[115] ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 249.

GasNet has argued that 6.0 per cent remains appropriate for the calculation of the rate of return for the forthcoming access arrangement period.[116] GasNet provided a paper it commissioned by NECG to support its proposal.[117]

The NECG paper reviews market risk premium estimates for Australia based on historical data and states that there is support for an estimate in the range of 6.0-8.0 per cent. NECG also reviews the benchmark approach used to estimate a market risk premium. This approach takes an estimate of the market risk premium for the US which is adjusted for Australia according to the difference between the US and Australian markets. NECG regards 6.0-9.0 per cent as an appropriate range for the US premium, with a mid-point of 7.5 per cent. The paper suggests that a greater representation of resource companies in Australia and the overall smaller size of Australian companies in comparison to US companies support an adjustment of 0.3 percentage points to the US market risk premium. NECG establishes an estimate of the Australian market risk premium of 7.8 per cent using this technique.[118]

The Commission has reviewed a number of works on the issue of market risk premium with particular reference to the regulatory use of CAPM. In addition, it commissioned Dr Martin Lally to assess various approaches to, and estimates of, the market risk premium. Lally determined that the average estimate for Australia was 6.1 per cent and noted that although many empirical estimates of the market risk premium were available they diverged significantly and there is no clear consensus value. He concluded that ‘all of this suggests that the ACCC’s currently employed estimate of .06 is reasonable, and no change is recommended’.[119] The Commission proposes to use 6.0 per cent as its estimate of market risk premium in relation to the PTS for the forthcoming access arrangement period.

5.5.4 Gearing

The rate of return for GasNet’s access arrangements was determined on the basis of a gearing ratio of 60:40 (debt:equity). This ratio has frequently been proposed by service providers. The Commission and other regulators have recommended this ratio as an appropriate benchmark for regulated entities.

GasNet proposes to continue with this gearing ratio for the forthcoming access arrangement period. The Commission considers this is appropriate and has adopted a ratio of 60:40 in its calculations of the benchmark rate of return for this Draft Decision.

5.5.5 Imputation credits

As noted earlier, the model used by the Commission to assess forecast regulated revenues is based on investor post-tax return requirements estimated using the CAPM. To ensure this return is expected to be achieved tax compensation is added as a separate

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[116] GasNet submission, 27 March 2002, pp. 55-57.

[117] NECG, *Market risk premium*, 23 November 2001 (GasNet submission, 27 March 2002 annexure 2).

[118] ibid., pp. 6 and 11.

[119] M Lally, *The cost of capital under dividend imputation*, June 2002, p. 34. A 6 per cent MRP has also been endorsed by Professor Officer: ‘Trends in market risk premium’ presentation to the open forum ‘Key WACC issues in the regulation of electricity and gas transmission’, 24 June 2002.

element in these forecast revenues. The forecast tax payments are just one element in this compensation for tax.

Another factor of critical importance for providing an appropriate level of compensation for tax is that, under the system of dividend imputation, Australian shareholders are able to receive a credit for tax paid at the company level when determining their personal income tax. The standard practice amongst Australian regulators and finance practitioners is to treat this benefit as an offset to the particular entity's company taxation liability.

The assumed value of imputation (or franking) credits is usually expressed as a proportion of their face value, with this proportion denoted by gamma (γ). This approach implies that if a regulated entity were assumed to pay \$X in company tax in a particular year, then the regulated entity would only require an allowance of $\$(1-\gamma)X$ for taxation compensation. The remaining $\$\gamma X$ would be provided directly to shareholders through the imputation system.

This interpretation of gamma holds regardless of whether the value of franking credits is reflected in the (pre-tax) WACC or in the cash flows. It is in this sense that gamma is one of the key CAPM and WACC parameters. The gamma also has a minor role in the levering formula used by the Commission to determine the equity beta from the asset beta. This formulation for the equity beta developed by Monkhouse requires the inclusion of gamma as a consequence of an assumption in its derivation that the company (consistent with the regulatory framework) has an active debt management policy aimed at maintaining a particular gearing ratio. However, in practice the impact on the equity beta is very small and insignificant in the context of revenue determination.

The value of gamma to an investor depends on whether franking credits are made available to investors by attaching them to dividend payouts from the firm and whether the taxpayer investor is fully able to utilise the value of the credit. For an Australian investor:

- there appears no logic or benefit in the company retaining such credits any longer than necessary; and

- recent changes under the new tax system allow the benefit to be received by Australian taxpayers as a rebate.

Empirical observation of the behaviour of Australian firms, confirms the first of these points and together with the second point strongly suggests the value of gamma used in the regulatory framework should be 1.0.[120]

However, GasNet has argued for a value of gamma of 0.5 to be consistent with previous regulatory decisions and to reflect the fact that, in its view, many owners of pipeline operations in Australia are not Australian taxpayers and do not benefit to the full extent from the Australian tax imputation system. It further points out that

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120 The evidence for payout of imputation credits is discussed in M Lally, *The cost of capital under dividend imputation*, a paper commissioned by the ACCC, April 2002.

empirical studies based on share movements when shares go ex dividend are consistent with a gamma value closer to 0.5 than 1.0.

This is to be expected when a significant portion of the shareholder base is not subject to Australian taxation. However, the observation is essentially irrelevant to the regulatory framework which consistently maintains the assumption that the equity investor is domiciled in Australia. This allows for consistency in applying the CAPM in the context of the Australian market and the fact that regulated services are provided to the Australian market. If the assumption were to be relaxed, it is not sufficient to merely adopt a different value of gamma. Instead, the whole CAPM framework would need to be revised to recognise the international context in which the foreign investors are operating. As a first step this involves the adoption of an international version of the CAPM model and reconsideration of the relevant CAPM parameters. Lally considers this issue in detail and provides strong evidence to show that reducing the value of gamma as a means of recognising the existence of foreign investors provides a perverse result.[121] Instead, his analysis shows that the costs of capital for foreign investors is somewhat less than their Australian counterparts and that setting gamma to 1.0 would not compromise the benchmark returns they require if their foreign status is fully considered.

Notwithstanding the strong evidence for a gamma value of 1.0 the Commission, for the purpose of this Draft Decision, has decided to retain an assumed value of gamma equal to 0.5 consistent with what was approved for the initial access arrangement period and other recent regulatory decisions. This maintains a sense of regulatory consistency and represents one of the concessions aimed at ensuring that the rate of return remains appropriate for the ongoing operation of the business. However, in future decisions, after the Lally analysis has been subjected to further debate, the Commission retains the option of revising the gamma parameter value to be more consistent with market evidence.[122]

5.5.6 Effective tax rate

The effective tax rate (T_e) is by definition a parameter which links the relationship between the post-tax return on equity (r_e) determined by the CAPM and the pre-tax return on equity (r_{te}) emerging from regulated cash flows.

$$r_e = r_{te} \times (1 - T_e)$$

The parameter is not required as an input to the post-tax framework for the determination of regulated revenues as described above except for an insignificant role in the calculation of the equity beta using the Monkhouse formula. The calculation of the tax compensation in the post-tax framework is based on estimated benchmark tax payments and not an assumed long term average rate of tax on returns. However, using the above relationship an effective tax rate can be calculated by simulating cash flow expectations over the life of the asset. Essentially, it is an outcome from the regulated

121 M Lally, *The cost of capital under dividend imputation,* a paper commissioned by the ACCC, April 2002.

122 Such revisions may not only involve gamma but also a revision of the CAPM framework to better recognise the status of foreign investors in Australian regulated infrastructure.

cash flows rather than an input. As a result of the deferral of tax payments well into the future the impost of tax is well below the current corporate company tax rate of 30 per cent. Simulations of the cash flows over 36 years, the average remaining life of the regulated assets originally proposed for the access arrangement, suggest that the effective tax rate for GasNet lies between 6 and 7 per cent. The number can only ever be approximate since the future impost of tax legislation is unknown and is usually approximated by assuming that existing tax rules are maintained.

5.5.7 Beta

Systematic risk is accommodated in the CAPM framework by the equity beta (β_e). This indicates the riskiness of one asset or project relative to the whole market (usually represented by the stock market). An equity beta greater than one indicates that the asset or project has returns that vary more than the market average. This risk cannot be eliminated through a well balanced and diversified portfolio (unlike specific risk).

To compare the risk associated with a number of businesses independent of their financial structure (gearing), equity betas are 'de-levered' to produce asset betas (β_a). While there are a number of levering formulae, the Commission consistently applies the formula developed by Monkhouse:[123]

$$\beta_e = \beta_a + (\beta_a - \beta_d)\left[1 - \left(\frac{r_d}{1+r_d}\right)(1-\gamma)\,T_e\right]\frac{D}{E}$$

The Commission determined that the appropriate asset beta for the initial PTS and WTS access arrangements was 0.55 (with a corresponding equity beta of 1.20). This value was selected following advice from experts that the Commission could accommodate some specific risks, such as self-insurance and other asymmetric costs, identified by the applicant through a beta 'towards the top end of the plausible range'. In addition, it was suggested that the value of the beta should reflect the applicant's view that revenue or price cap regulation is more risky than rate of return regulation and that the new regulatory regime introduced perceived uncertainties for investors.[124]

GasNet considers an asset beta of 0.60 is appropriate for its business for the forthcoming access arrangement period and has adopted this in its CAPM calculations. With a debt beta of 0.06, based on previous Commission decisions, GasNet has calculated an equity beta of 1.40.[125]

GasNet commissioned a report by NECG regarding beta.[126] NECG noted that due to the limited period that GasNet has been a listed company a direct measure of an asset beta for the business is not possible. Accordingly, NECG proposed that the 'method of similars' be used to determine an approximate asset beta for GasNet. Four sources of information were used by NECG in this process.

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123 See ACCC, DRP, pp. 79-81.

124 ACCC, 1998 Final Decision, pp. 59-61.

125 GasNet access arrangement information, 27 March 2002, p. 6.

126 NECG, *Asset, equity and debt beta*, 4 January 2002 (GasNet submission, 27 March 2002 annexure 5).

First, a number of earlier Australian regulatory decisions relating to gas and electricity infrastructure were considered. From this information NECG suggests that an appropriate range for gas transmission assets is 0.50-0.60.

Second, NECG considered data from a recent QCA regulatory decision on electricity distribution, which provides beta estimates for a number of energy businesses. Data on Allgas, AGL and United Energy provided an asset beta range of 0.42-0.47 and an average of 0.44.

Third, available data for comparator businesses was considered. Equity beta data from the Australian Graduate School of Management (AGSM) risk management service was de-levered by NECG, according to the Monkhouse formula, to obtain asset beta estimates. The companies used were AGL, Energy Developments, Envestra and United Energy. NECG regard AGL and United Energy as the closest comparators and, as a result, conclude that the relevant range is 0.47-0.51 for the asset beta.

Fourth, equity beta data from the Dow Jones Interactive website were used to estimate asset betas for several companies. NECG regards AGL, Origin Energy, Energy Developments and United Energy as the most relevant comparators (it excludes AlintaGas, APT and Envestra), resulting in a range of 0.50-0.63.

NECG concludes that a plausible range for an asset beta of a gas transmission company would be 0.45-0.65. It states that the appropriate value for GasNet in this range will be influenced by a number of factors including regulatory arrangements, the possibility of bypass, correlation of gas demand with economic activity and size. In addition, NECG considers that the industry is becoming an ‘increasingly competitive and volatile environment for gas transmission companies’ and that ‘the inevitable conclusion therefore is that, GPU GasNet is likely to be entering a period of higher systematic risk’.[127]

GasNet reiterates NECG’s view that the business has some distinctive features that indicate that it is particularly sensitive to changes in GDP, which implies a higher asset beta. These features are:

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

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

(c) under the Service Envelope Agreement and MSO Rules GasNet is “locked in” to a market carriage regime and does not have significant revenues secured under take or pay contracts, as is the norm on contract carriage gas transmission systems.[128]

GasNet argues that these features have had a very real impact on the business during its initial access arrangement period. GasNet’s volumes have been significantly lower than those forecast (and used to determine reference tariffs) and have resulted in a

127 ibid., p. 20.

128 GasNet submission, 27 March 2002, p. 64.

revenue shortfall that is expected to exceed $19.3 million.[129] These events, according to GasNet, indicate that the current asset beta of 0.55 is 'understated' and support its argument that the asset beta should be 0.60.

In contrast, Origin considers that the beta for the forthcoming access arrangement period should be less than the current value because the revised demand forecasts are based on more conservative assumptions, reducing GasNet's exposure to the volume shortfalls that it experienced in the initial access arrangement period. It also considers that the amended operation of the K factor reduces the need for a high beta. Origin concludes that there are 'no unique circumstances applying in the forthcoming period that are consistent with GasNet claiming a higher asset beta (and therefore a higher pre-tax real WACC) than the previous access arrangement'.[130]

Amcor and PaperlinX consider that GasNet has moved risks relating to volume, asymmetrical events and pass through events onto users. By not accepting these risks, which would be carried by businesses operating in a competitive environment, GasNet has reduced its risk profile and should receive a lower return.[131]

EnergyAdvice notes that, if implemented, the proposed tariff design will result in a greater proportion of revenues recovered from volume based charges compared to the peak day charges. This change increases the risk exposure of GasNet's revenue. EnergyAdvice questions whether it is reasonable for users to pay higher tariffs (due to a higher rate of return) as a result of GasNet compounding its risk.[132]

A report prepared for the Commission by ACG regarding beta included some responses to NECG's report. First, of the four sources of information used by NECG, ACG regard three as not being independent. Instead it considers them to be different calculations or approaches using the same primary information source from the AGSM. The Commission agrees with ACG's view that:

> The use of a widely available and frequently-updated beta estimation service also permits the same beta estimation methodology to be used across decisions and industries, and thus reduce the uncertainty associated with the regulatory process. ... By committing to use a credible, independent source for beta estimates, the likelihood that regulators or regulated entities may seek (or appear to seek) to cherry-pick the methodological choices to produce their desired result should be reduced and thus reduce the uncertainty and controversy associated with price reviews.[133]

Second, ACG raises concerns regarding the businesses included in NECG's derivation of beta for GasNet using the comparator business approach. It does not agree with NECG's exclusion of Envestra (a gas transmission and distribution business with the majority of activities under price cap regulation). In addition, ACG did not agree with the inclusion of Energy Development (whose business is largely electricity generation)

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129 The Commission understands that the majority of this total is recoverable through the average price control mechanism. GasNet response to Commission, 1 August 2002.

130 Origin submission, 17 May 2002, p. 7.

131 Amcor and PaperlinX submission, 24 June 2002, p. 23.

132 EnergyAdvice submission, 30 May 2002, p. 9.

133 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 46.

and Origin (that carries out gas production, gas and electricity retailing and LPG supply).

In addition, ACG questioned NECG's assertion that the Commission had implicitly adopted the 'Blume adjustment' to beta data. It also expressed concern regarding NECG's comments on the relationship between asymmetric risk and CAPM and the relative risk of GasNet's business. ACG also noted that the NECG had not disclosed the assumptions it made regarding the debt beta.

ACG undertook an assessment of beta for Australian gas transmission businesses. Using data from the AGSM, ACG considered that the data imply an equity beta estimate of 0.7.[134] ACG also considered data for comparable businesses in the US, Canada and UK. This data produced lower beta estimates and ACG concluded that this secondary information supports the view that Australian estimates are not understated. ACG stated:

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North American or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.[135]

ACG recommends that a conservative approach to beta estimation be retained by Australian regulators with an equity beta estimate of one. ACG notes:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[136]

The Commission has considered the information provided by various parties in regard to beta estimation. It is concerned with some aspects of GasNet's NECG report (such as the selection of comparator companies) as noted by ACG. It has also considered GasNet's views on its 'distinctive features' that are said to support a high beta. The Commission does not consider that these features relate to the systematic risk of the business and consequently, should not impact on beta. In particular, it should be noted that GasNet is regulated under an average revenue control mechanism, and not a price cap as suggested.

The Commission acknowledges that the beta estimate adopted in the 1998 Final Decision accommodated some aspects of specific risk. However, the Commission has worked to refine its approach to beta, and CAPM in general, subsequent to that decision. It does not consider it appropriate to continue with these ad hoc adjustments merely because they were carried out in the past. In particular, it does not consider that

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[134] The result of 0.7 reflects calculations for the equity beta for Australian gas transmission businesses that result in a range of 0.66 to 0.69. The calculations assumed a debt:equity ratio of 60:40 and used data from AGL, Australian Pipeline Trust, Envestra and United Energy. Variables included excluding and including tax from the re-levering formula and a debt beta of either 0 or 0.15. ibid., pp. 39-41.

[135] ibid., p. 42.

[136] ibid., p. 43.

an adjustment for the uncertainty due to the 'newness' of the regulatory regime is appropriate any longer.

For GasNet, the Commission must also consider whether the business has changed such that its risk relative to the market in general has fundamentally changed since 1998. The Commission is not aware of any supporting evidence that the systematic risk of GasNet has changed significantly. However, it does note that it proposes to accept the removal of the feature of the revenue control formula which allowed most of the GasNet's first period revenue shortfall to accrue.

In addition, the Commission notes that the equity beta estimate used in the 1998 Final Decision was 1.2. This suggests that the business experiences greater volatility than the market in general. This does not appear to be consistent with the frequently held view that gas, and electricity, utilities are less risky and more stable than the market average. Greater stability suggests that the equity beta should be less than one.

The Commission has considered the information presented by GasNet as well as other interested parties in its assessment of the appropriate asset beta for the business. In particular, it has referred to the report prepared by ACG which indicates that the current appropriate asset beta for Australian gas transmission businesses may be between 0.27 and 0.37.[137] However, for the reasons indicated by ACG in reference to the equity beta as noted above, the Commission considers that it may be premature to rely on market data exclusively when determining the asset beta. Accordingly, the Commission considers that an asset beta (β_a) of 0.5, while biased in favour of the service provider, is appropriate for GasNet at this time.

The upper limit to the debt beta (β_d) can be determined from the formula:

$$\beta_d = \frac{r_d - r_f}{MRP}$$

With the current proposed values for the relevant parameters, the calculation results in a debt beta of approximately 0.23. However, the ESC has recently undertaken work to provide further insight into the debt beta. It concluded that the debt beta is likely to be between 0 and 0.18 although a value toward the upper end of this range was more likely.[138] ACG has also considered this information and suggested that an appropriate range for the debt beta would be between 0 and 0.15.[139] On balance, the Commission considers that an appropriate value for the debt beta for this Draft Decision is 0.15.

Accordingly, through the application of the Monkhouse formula noted above, the equity beta for GasNet will be 1.0 for this Draft Decision. This represents the absolute upper limit of a possible range for the equity beta suggested by ACG analysis of available empirical evidence.

137 ibid., p. 40.

138 ESC, *Draft Decision: review of gas access arrangements*, July 2002, pp. 231-233.

139 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, pp. 28-29.

5.5.8 The return on equity

The rate of return critical to the regulatory framework applied by the Commission to a regulated business is the expected post-tax nominal return on equity (r_e). This return determines whether investors will be willing to provide equity to finance the infrastructure.

The various CAPM parameters proposed by GasNet are included in Table 5.3 below. Using the CAPM formula the return on equity proposed by GasNet is 14.19 per cent. In comparison, the parameters proposed by the Commission, as outlined above, result in a post-tax nominal return on equity of 11.86 per cent. The corresponding real return on equity is 9.13 per cent.

Table 5.3: CAPM parameters

		ACCC Final Decision October 1998	GasNet proposal March 2002	ACCC Draft Decision August 2002
real risk free rate	rr_f	3.43	3.20	3.14
expected inflation	f	2.50	2.50	2.51
nominal risk free rate	r_f	6.00	5.78	5.72
debt margin	DM	1.20	1.20	1.38
real cost of debt	rr_d	4.60		4.49
nominal cost of debt	r_d	7.22	6.98	7.10
market risk premium	MRP	6.0	6.0	6.0
corporate tax rate	T_c	0.36	0.30	0.30
effective tax rate	T_e	0.27		0.07
use of imputation credits	γ	0.50	0.50	0.50
debt funding	D/(D+E)	60	60	60
debt beta	β_d	0.12	0.06	0.15
asset beta	β_a	0.55	0.60	0.50
equity beta	β_e	1.20	1.40	1.0
nominal return on equity	r_e	13.22	14.19	11.86
real return on equity	rr_e	10.45		9.13

Source: ACCC, 1998 Final Decision, p. 62; GasNet access arrangement information, 27 March 2002, pp. 6-7; ACCC analysis.

5.6 Determination of the WACC

GasNet has stated that it has generally selected WACC parameters that are within the range adopted by the Commission in recent decisions. However, it proposes a higher value for beta. In addition, it departs from normal Commission practice by proposing cash flow adjustments to reflect asymmetric risks and the use of 10 year bond rates to derive the risk free rate. GasNet regards its approach as developing an appropriate return that supports the long run benefits of infrastructure development within a framework that has ‘inherent uncertainty’.[140]

Gas Net suggests that the Commission should identify the possible range for the rate of return and then exercise its discretion in selecting a value. Where there is uncertainty GasNet recommends that ‘the Commission err on the side of favouring a higher return. GasNet submits that this is required both from an economic and legal perspective’. It regards this approach as ‘preferable as the welfare benefits of the long run objectives far outweigh the short run benefits of lower prices’.[141]

BHP Billiton accepts that it is important to avoid disincentives to infrastructure investment but does not consider that this should lead to monopoly rents. It suggests that the removal of monopoly rents will allow investment in both upstream and downstream markets to occur. It considers that ‘the need for a high WACC on existing assets to encourage future investment is not a sustainable argument’.[142]

BHP Billiton asserts that the appropriate WACC for GasNet for 2003-2007 is less than 7 per cent. It notes that the high prices paid for the Victorian gas assets subsequent to the establishment of the regulatory regime in 1998 indicate that the returns selected by the Commission and the Office of the Regulator-General, Victoria (ORG) were too high.[143] The EUAA notes the oversubscription of the GasNet float as further support for this view.[144]

As acknowledged by GasNet, the various CAPM parameters used in regulatory decisions will often be contentious as they impact directly on the return expected by infrastructure owners and operators through their influence on the tariffs paid by users.

The Commission considers that an important aspect of its regulatory decisions is the selection of specific estimates of the values of the CAPM parameters, and the associated discussion on the parameter values chosen. Using point estimates of inputs allows the CAPM outputs and cash flow analysis carried out by the Commission to also be clearly numerated, consistent and repeatable. The Commission considers that this transparency and repeatability is an important feature of its regulatory approach. In contrast, approaches that generate a wide range of possible outputs can require the exercise of a degree of regulatory judgement which may lead to considerable uncertainty for service providers and other stakeholders. In addition, use of specific values can make it easier to pinpoint contentious aspects which may warrant closer examination.

While the Commission does not propose to adopt the approach of identifying CAPM parameter ranges, it has considered carefully the likely costs of under and over estimating a service provider’s cost of capital:

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140 GasNet submission, 27 March 2002, p. 45.

141 ibid., p. 48.

142 BHP Billiton submission, 21 June 2002, pp. 6 and 31. See also Amcor and PaperlinX submission, 24 June 2002, p. 24.

143 BHP Billiton submission, 21 June 2002, p. 32. See also Amcor and PaperlinX submission, 24 June 2002, p. 24.

144 EUAA submission, 11 July 2002, p. 8.

> While the CAPM/WACC framework provides a well recognised theoretical framework to establish the cost of capital, there is less than full agreement on the precise magnitude of the various financial parameters which need to be applied (as evidenced by the range of parameter values suggested by different commentators). ... The Commission has given careful consideration to the value that should be assigned to TPA given the nature of its business and current financial circumstances. Accordingly, the parameter values used are those considered most appropriate. Mostly these fall near the middle of a narrow range based on the information available, however a few, such as the equity beta and the margin on debt, have been chosen to give TPA the benefit of associated uncertainty.[145]

However, the Commission has considered with some sympathy the suggestion by GasNet that, where there is uncertainty, the Commission should err on the side of favouring a higher return. The Commission has done this in a number of ways. For example, it has applied a value of gamma of 0.5 rather than 1.0, and selected a higher equity beta value than that suggested by the empirical evidence. Other concessions include not taking into account pre-payments for future tax liabilities already received in calculating the future compensation for benchmark tax liabilities and other elements of costs added to the cash flows not featured in the 1998 Final Decision. A number of other relevant aspects of the Commission proposals, which need to be viewed in totality, are noted in the Executive summary.

As with other access arrangement decisions the Commission has calculated a benchmark WACC for GasNet. A cash flow model has been used to determine the WACC that will achieve cash flows that are consistent with the post-tax nominal return on equity that has been calculated through the CAPM.

In this instance, the Commission has found that a pre-tax real WACC of 6.5 per cent is consistent with the post-tax nominal return on equity of 11.9 per cent for GasNet.[146] This compares to the pre-tax real WACC of 8.22 per cent proposed by GasNet.[147] However, consistent with the post tax approach favoured by the Commission, the real vanilla WACC is the appropriate WACC to use for the calculation of return on assets. The real vanilla WACC of 6.4 per cent is consistent with the post-tax nominal return on equity of 11.9 per cent. Consistent with the use of a real vanilla WACC, an extra line is added to the building block approach for the recovery of taxes. However no such amendment is proposed by the Commission for the next access arrangement period as the modelling suggests that GasNet will not be liable for any taxes in this period.

The Commission will continue to use a post-tax method of evaluation and suggest that GasNet do the same.

Accordingly, the Commission proposes the following amendment in relation to the appropriate return for GasNet.

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145 ACCC, 1998 Final Decision, p. 63.

146 The nominal vanilla WACC is 9.0 per cent and the implied real tax wedge 0.2 per cent.

147 The nominal vanilla WACC under GasNet’s proposal is 9.86 per cent and the implied real tax wedge 1.04 per cent.

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GasNet must adopt the Commission's CAPM parameters as set out in Table 5.3 of this Draft Decision to more accurately reflect the current financial market settings. GasNet must use the real vanilla WACC of 6.4 per cent to calculate the return on asset component of revenues for its revised access arrangement.

6. Revenue elements

This chapter considers a number of the components that make up GasNet's benchmark revenue. Elements considered are: operations and maintenance expenditure; the K factor adjustment; the efficiency carryover; working capital; allowances for asymmetric risks; capital expenditure; depreciation; and pass through amounts.

6.1 Operations and maintenance expenditure

6.1.1 Code requirements

The Code (sections 8.36 and 8.37) allows for recovery of the operating, maintenance and other non capital costs that a prudent service provider, acting efficiently and in accordance with good industry practice, would incur in providing the reference service. Non capital costs may include, but are not limited to, costs incurred for generic market development activities aimed at increasing long-term demand for the delivery of the reference service.

Attachment A to the Code requires the service provider to disclose certain costs in the access arrangement information, unless it would be unduly harmful to the legitimate business interests of the service provider, or user or a prospective user. The costs to be disclosed include wages and salaries, contract services including rental equipment, materials and supply, and corporate overheads and marketing. The service provider must also disclose gas used in operations. Some disaggregation by zones, services or categories is also required.

6.1.2 Current access arrangement provisions

Forecast operations and maintenance expenditure for the initial access arrangement period is detailed in the access arrangement information for the PTS and WTS. Table 6.1 below shows annual operations and maintenance cost forecasts for this period disaggregated into various components.

Table 6.1 also presents actual costs achieved by GasNet in the first access arrangement period. As indicated by the table, GasNet's operations and maintenance expenditure was substantially lower than that which was forecast, particularly for 1999 to 2001. GasNet expressed concern that interested parties might misconstrue these data which it considers reflect unsustainable savings. This issue is discussed below and also under access arrangement information in section 9.5 of this Draft Decision.

Table 6.1: Benchmark and actual operations and maintenance costs, 1998 to 2002

	$ million				
	1998	1999	2000	2001	2002
Labour	6.33	6.48	6.53	6.58	6.75
Total materials	1.04	1.05	1.06	1.06	1.09
Total outside services	6.39	6.20	5.79	5.24	4.91
Occupancy	0.85	0.86	0.86	0.87	0.89
Communications	0.17	0.18	0.18	0.18	0.18
Total motor vehicles	0.70	0.70	0.70	0.71	0.73
PC, furniture, office equipment	0.59	0.55	0.51	0.53	0.56
Training and conferences	0.27	0.28	0.28	0.29	0.29
Travel and accommodation	0.26	0.26	0.27	0.27	0.28
Miscellaneous taxes	0.88	0.87	0.88	0.89	0.91
Sundry	0.62	0.62	0.63	0.64	0.66
Fuel gas	1.10	1.14	1.23	1.25	1.30
Murray Valley	0.08	0.20	0.20	0.21	0.21
Total[a]	19.29	19.38	19.11	18.70	18.75
Actuals achieved	16.97	14.14	11.86	13.90	18.55[b]

Source: TPA access arrangement information, 30 November 1998, p. 8; GasNet response to Commission, 9 May 2002.

Notes: (a) This total incorporates annual regulatory costs that were forecast but not paid by GasNet. The data only relates to the PTS and WTS. It does not include forecast costs associated with the Interconnect Pipeline, Springhurst compressor, Iona compressor and the Southwest Pipeline.

(b) Estimated actual 2002.

6.1.3 GasNet proposal

GasNet forecasts that costs will increase from $18.4 million in 2003 to $22.0 million in 2007 in nominal terms. Forecasts for every year except 2003 are higher than the estimated actual in 2002 of $18.55 million. A breakdown of forecast costs is presented in Table 6.2.

Table 6.2: Forecast operations and maintenance expenditure, 2003 to 2007

	$ million[a]				
	2003	**2004**	**2005**	**2006**	**2007**
Pipeline maintenance	5.9	6.8	6.2	7.4	7.4
Compressor maintenance	3.3	3.6	3.7	3.7	3.8
General and administrative	8.0	8.4	8.6	8.9	9.1
Fuel gas	1.2	1.3	1.4	1.6	1.7
Total	18.4	20.1	19.9	21.6	22.0

Source: GasNet submission, 27 March 2002, p. 83-84.
Note: (a) Nominal dollars.

GasNet provides a number of reasons for increases in costs. These include: an increase in pigging operations on a number of the older pipelines in the system over 2003 to 2007; an allowance for ongoing litigation expenses arising from the Longford incident; an extraordinary increase in insurance costs; the need to bolster the company's skill base and recruit junior staff; and an allowance for the expansion of general marketing activities.[148]

6.1.4 Submissions

Amcor and PaperlinX comment in their submission that GasNet has provided limited comparative data in relation to its proposed operations and maintenance expenditure. They contend that a number of different benchmark divisors should be assessed rather than single variables, and that the aggregate of GasNet and VENCorp costs should be used when undertaking benchmarking. Further, they comment that any operations and maintenance costs should be related to the benefit the consumer receives. In this regard, Amcor and Paperlinx are particularly concerned with an allowance for marketing of gas, arguing that GasNet does not substantiate this claim and does not reference expected outcomes from this marketing activity. Amcor and PaperlinX propose that GasNet should provide further information to substantiate its claims.[149]

BHP Billiton states that GasNet includes an allowance for marketing costs, but does not include what outcomes are expected from this marketing activity.[150] BHP Billiton expresses concern with the extent of information provided by GasNet. BHP Billiton states that GasNet does not include the amounts forecast for the first access arrangement period for comparison with the actual expenditure incurred. It also notes that operations and maintenance cost forecasts for 2003-2007 do not appear to recognise any savings made in the first access arrangement period.[151]

[148] GasNet submission, 27 March 2002, pp. 83, 85 and 89.

[149] Amcor and PaperlinX submission, 24 June 2002, pp. 21-22.

[150] BHP Billiton submission, 17 May 2002, pp. 12-13.

[151] BHP Billiton submission, 21 June 2002, p. 43.

TXU expresses concern with the lack of historical operations and maintenance expenditure information and suggests that a statement of historical operating costs and capital expenditure be provided as a baseline.[152]

EnergyAdvice expresses concern relating to the appointment of a business development manager to promote gas use. EnergyAdvice notes:

> Given the magnitude of the initial tariff increases which are effectively locked in over the next five years, GasNet may have a difficult job attracting new or incremental loads. This is particularly true of customers who will have experienced significant price shock as a result of this Access Undertaking being implemented in its present form and were contemplating further use of gas for plant expansion or new projects.[153]

EnergyAdvice also comments on the inclusion of ongoing litigation expenses for the Longford incident in 1998. It suggests that if GasNet is successful in its legal action, the cost base should be reduced accordingly, and that if GasNet receives a judgement against it, then it should bear the resultant cost.[154]

6.1.5 Commission's considerations

The Commission has assessed the operations and maintenance costs proposed by GasNet. The following discussion outlines the Commission's considerations on a number of operations and maintenance cost forecasts.

Marketing costs

The forecasts proposed by GasNet include an annual allowance of $400 000 to promote growth in gas volumes. This represents an increase from $120 000 in 2002 allowed in the current access arrangement provisions. GasNet comments that marketing costs are required as it faces substantial volume risk. GasNet also contends that it must provide a supportive role in the marketing of gas, particularly to large-use applications such as cogeneration and power-station developments.[155]

As noted, Amcor and PaperlinX expressed concern with the allowance for gas marketing on the basis that GasNet does not substantiate the claim and does not reference expected outcomes from this marketing activity. EnergyAdvice also commented on the inclusion of these costs. While the Commission acknowledges the concerns raised, it considers that the proposed allowance for marketing costs is not unreasonable. Further information from GasNet clarified that the objective of the marketing allowance is to encourage gas usage in Victoria through liaison with potential large users such as power station, cogeneration and large gas-using industrial projects.[156] The Commission considers that such marketing activities correspond with generic market development activities allowed for under section 8.36 of the Code and proposes to accept the forecast cost in the determination of revenues and tariffs. It will review GasNet's actual marketing expenditure during the second access arrangement period at the next scheduled review of the access arrangement.

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152 TXU submission, 31 May 2002, p. 32.

153 EnergyAdvice submission, 30 May 2002, p. 9.

154 ibid., p. 10.

155 GasNet submission, 27 March 2002, p. 89.

156 GasNet response to submissions, 12 June 2002, p. 23.

Exceptional costs

GasNet has provided a breakdown and a discussion of exceptional costs claimed for the second period.[157] The Commission understands that a number of the exceptional costs noted by GasNet generally relate to both regulated and unregulated GasNet operations (specifically, listing and governance costs, increases in insurance costs), and therefore overestimate the amount which is relevant for determining the reference tariffs. The Commission therefore requires that GasNet correct these figures to allow an assessment to be carried out prior to the Final Decision.

Proposed amendment 9

GasNet must amend Table 8-3 and section 8.3.4 of its submission relating to exceptional costs to reflect only the portion of costs that relate to regulated assets. It must also change operations and maintenance cost forecasts in its access arrangement information to reflect these changes.

Ongoing litigation expenses

GasNet has made an allowance for ongoing litigation expenses arising from the Longford incident in 1998 of $200 000 annually in 2003-2007 (nominal terms).[158] The Commission considers that this allowance is not appropriate given that the Longford incident occurred prior to the commencement of the first access arrangement period, and GasNet was compensated for such risks through the beta parameter in the first access arrangement. Furthermore, it is unreasonable to expect users to fund GasNet's litigation given that GasNet has not proposed to share any compensation received with users should it be successful in court.

Proposed amendment 10

GasNet must amend section 3.5 of its revised access arrangement information so that operations and maintenance cost forecasts do not include the annual recovery of litigation expenses.

Licence fees

GasNet has forecast an amount for pipeline licensing fees in its proposed operations and maintenance costs. These fees and levies form a substantial part of the $1.3 million regulatory/utility charges claimed by GasNet in Table 3-7 of the access arrangement information.[159]

The Commission acknowledges that GasNet is required to pay licence fees and charges to a number of government authorities. GasNet has provided data to the Commission disaggregating the total payable into specific licence fees and levy components. The Commission has assessed these components and considers that they are not unreasonable.

157 GasNet submission, 27 March 2002, p. 90.

158 ibid., p. 90.

159 GasNet access arrangement information, 27 March 2002, p. 9.

Regulatory review costs

In Table 8-3 of GasNet's submission summarising exceptional costs, GasNet notes an allowance for reset costs of $0.5 million in 2002, $1.0 in 2006 and $0.6 in 2007. This allowance is to cover the costs associated with the access arrangement revision process in those years. The Commission understands that GasNet intends to recover reset or regulatory review costs incurred in 2001 and 2002 in 2003 tariffs, and that these costs have not been included in operations and maintenance cost forecasts presented in Tables 3-6 and 3-7 of its proposed access arrangement information as they are yet to be finalised.

In addition, GasNet has not included forecast review costs for 2006 and 2007 in its proposed access arrangement information. The Commission understands that GasNet proposes to recover these costs in the third, rather than the second period, as these costs relate to revisions to the access arrangement for the third period.

The Commission considers that it is reasonable to include prudent regulatory review costs incurred in 2001 and 2002 in the reference tariffs for 2003. As noted, GasNet has estimated review costs in 2002 of $0.5 million. In addition to this amount, GasNet also incurred an undisclosed amount in 2001 associated with the preparation of the revisions to the access arrangement. It is therefore likely that the total figure that will be claimed by GasNet will be in excess of $0.5 million. GasNet must publicly provide a detailed itemised breakdown of these costs as part of the current assessment process so that the Commission and interested parties can assess whether the costs incurred are prudent.

The Commission considers it is appropriate to not include forecasts for review costs in 2006 and 2007 in the reference tariff calculation for the second access arrangement period. The Commission acknowledges that this approach to the treatment of operations and maintenance expenditure represents a departure from incentive regulation, but as noted in relation to the proposed pass through mechanism (section 3.2.3 of this Draft Decision), this approach is acceptable under the provisions of the Code.

Proposed amendment 11

GasNet must amend section 3 of its revised access arrangement information so that operations and maintenance costs in 2003 include a recovery for regulatory review costs incurred in 2001 and 2002. GasNet must publicly provide a detailed itemised breakdown of these costs so that the Commission and interested parties can assess whether or not these costs are prudent.

Insurance costs

GasNet proposes an increase in insurance costs from an amount of $0.3 million per year in the first access arrangement period to $1.7 million per year.[160] The Commission understands that this figure is one of the exceptional costs incorrectly calculated (as noted above), and is therefore slightly higher than the figure which should be used to calculate reference tariffs.

[160] ibid., p. 90.

The Commission was concerned with the large increase in insurance costs and requested GasNet to substantiate their claim. In response, GasNet provided the Commission with invoices relating to the various insurance policies held by GasNet. The Commission has assessed this information and found all costs to be legitimate. As a result, the Commission proposes to accept these costs when amended according to the proposed amendment above.

Pigging schedule

GasNet intends to undertake substantial pigging activities in the 2003-2007 period.[161] The Commission requested further clarification on this issue, and GasNet agreed to release a list of current and planned pigging operations for 2001-2007. This information is presented in the table below:

Table 6.3: Current and planned pigging operations, 2001-2007

Line name	Recorded length (km)
Brooklyn to Ballan	66.6
Euroa to Shepparton	34.5
Shepparton to Tatura	16.2
Tatura to Kyabram	21.3
Ballan to Ballarat	22.7
Ballan to Bendigo	90.8
Derrimut to Sunbury	24.0
Guildford to Maryborough	31.4
Mt Franklin to Kyneton	24.5
Mt Franklin to Bendigo	50.8
Wandong to Kyneton	59.5
Dandenong to West Melbourne	36.18
South Melbourne to Brooklyn	12.8
Tyers to Morwell	15.7
Pakenham to Wollert	93.1
Morwell to Dandenong	126.8
Longford to Dandenong	174.2
Keon Park to Wollert	14.1
Rosedale to Tyers	34.3
Longford to Rosedale	30.5
Bunyip to Pakenham	18.7

Source: GasNet response to Commission, 2 August 2002.

This information will be used in the assessment of operations and maintenance expenditure achieved in the second period during the next revisions process.

The costs associated with this pigging program have been assessed by the Commission and found to be not unreasonable. Consequently, the relevant expenditure has been included in the determination of revenues and tariffs for 2003 to 2007. The Commission notes that, although GasNet adopts a fifteen year pigging cycle, no

161 ibid., p. 85.

associated expenses were reported for 1998, 1999 and 2000[162]. To the extent that pigging operations have been deferred, additional costs would be expected in the second access arrangement period.

Executive remuneration

The Tariff Order specifies a number of fixed principles to be used by the Commission for the second access arrangement period. Clause 9.2(a)(6)(C) requires the regulator to have regard to:

> The level of executive remuneration in TPA by reference to any relevant interstate and international private sector benchmarks for that remuneration.

This information was not provided to the Commission in the initial information provided by GasNet dated 27 March 2002. Accordingly, the Commission requested information from GasNet on executive pay, which was provided on a confidential basis. This information was assessed against Australian and overseas benchmarks, and the Commission has concluded that the amounts reported by GasNet are reasonable.

Assessment of broad cost categories

The Commission has also undertaken an assessment of forecasts for the following general operations and maintenance cost categories: pipeline maintenance, compressor maintenance, general and administrative costs and fuel gas costs. Commission assessment of normalised pipeline maintenance, compressor maintenance and general and administrative costs net of exceptional costs suggests that the forecasts proposed by GasNet are not unreasonable. The Commission requested and was provided further information substantiating GasNet's forecast fuel gas costs.[163] Assessment of this information also suggests that the forecasts proposed by GasNet are not unreasonable.

Further, GasNet has provided the Commission with key performance indicators relating to the forecast operations and maintenance costs in 2003 (net of working capital and compressor fuel costs), and a detailed benchmarking report compiled by Cap Gemini as an annexure to its submission. The Commission has assessed the benchmarks provided by GasNet, and this discussion is presented in section 10.2 of this Draft Decision.

Increase in operations and maintenance expenditures

As noted, GasNet has achieved operations and maintenance costs that are significantly below those forecast. For example, in 2001 a total of $18.70 million was provided for in reference tariffs, but GasNet's total expenditure was only $13.90 million. Further, GasNet has proposed forecast operations and maintenance costs per year in the range of $18.4 to $22 million (nominal) for the subsequent access arrangement period.

GasNet considers that the decline in actual operations and maintenance costs in the first access arrangement period was not sustainable. GasNet states that it managed 'to temporarily reduce some costs in response to large revenue losses resulting from warm weather and lost gas sales' during that period.[164] GasNet added that the reduction in

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[162] ibid., p. 85.

[163] GasNet response to Commission, 11 July 2002.

[164] GasNet response to submissions, 24 July 2002, pp. 16-17.

costs was achieved through delays in filling vacant positions, lower levels of business marketing and reduced levels of administrative support.[165] In addition, as noted above, no pigging expenses were reported for 1998, 1999 and 2000. As any deferred pigging operations would need to be undertaken in later years, associated costs savings would not be sustainable.

GasNet has also substantiated the proposed forecast increase in costs in the second access arrangement period. Apart from the temporary gains made in the first period, the large ‘step’ increase in costs between 2001 and 2003 is primarily the outcome of:

- the extraordinary increase in insurance costs;
- the proposed increase in pigging operations in 2003-2007;
- additional ongoing costs related to the public listing of GasNet on the Australian stock exchange;
- the proposed increase in marketing costs; and
- the increase in staffing levels and training of junior staff to a level that is sustainable for the operation of GasNet.[166]

The Commission has undertaken a detailed assessment of the costs forecast by GasNet in the second period and has proposed several amendments above. The Commission considers the remaining increase in operations and maintenance costs proposed by GasNet between 2001 and 2003 is not unreasonable.

Conclusion

The Commission has undertaken a detailed assessment of the forecast operations and maintenance costs proposed by GasNet for the period 2003 to 2007 and has drawn the following conclusions:

- GasNet’s operations and maintenance forecasts presented in the access arrangement information should be adjusted to remove the proposed annual recovery of litigation expenses;
- GasNet must provide information on access arrangement review costs incurred in 2001 and 2002 to the Commission as part of the current access arrangement and access arrangement information approval process. GasNet must also publicly provide an itemised breakdown of these costs. The Commission will assess these costs and, if deemed prudent, will incorporate them in the forecasts for 2003; and
- GasNet must correct the figures in Table 8-3 of its submission and the text relating to exceptional costs in section 8.3.4 to only reflect the portion of costs that relate to regulated assets. GasNet must also change operations and maintenance cost forecasts in its access arrangement information to reflect these changes

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[165] GasNet submission, 27 March 2002, p. 89.

[166] ibid., pp. 83, 85, 89-90.

6.2 Other non capital expenditure

6.2.1 Capital raising costs

Current access arrangement provisions

The current access arrangement provisions implicitly incorporate debt raising costs in the debt margin provided to GasNet. There is currently no provision for equity raising costs.

GasNet proposal

GasNet proposes to include capital raising costs as a separate annual non capital cost payment. Specifically, the company proposes an allowance of $0.5 million per year for equity raisings, and $2.0 million per year to compensate for debt financing costs. GasNet considers that the debt raising costs incorporate the fees and charges associated with debt facilities, and that the equity raising costs represent a proxy for the transaction costs associated with raising equity capital.[167]

Submissions

BHP Billiton comments that GasNet's capital structure is an issue for GasNet alone, and that a notional capital structure should be used by regulators. BHP Billiton suggests there is a series of cost estimates that compensate the service provider for each core element. It argues that this process inherently allows for capital raising costs facing the firm, and that additional capital raising expenses should not be incorporated in tariffs.[168]

TXU states that it was 'surprised' at the addition of an annual $2.5 million allowance for capital raising costs.[169]

Commission's considerations

The Commission considers that, in general, it is reasonable to provide an allowance for debt and equity raising costs.[170] These costs should be determined by reference to reasonable costs facing a benchmark gas transmission or distribution entity. The Commission is of the view that capital raising costs must be assessed in conjunction with the related issues of the cost of debt and operations and maintenance expenditures.

Debt raising costs

To raise debt, a benchmark service provider has to pay debt-financing costs over and above the debt margin. One cost that is incurred is the additional payment made to a bank or financial institution for the arrangement of debt.[171] The Commission considers that an allowance should be provided for a reasonable benchmark of debt financing

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[167] GasNet submission, 27 March 2002, pp. 101-102.

[168] BHP Billiton submission, 21 June 2002, p. 24.

[169] TXU submission, 31 May 2002, p. 33.

[170] Australian regulators have not generally recognised these costs explicitly. Implicitly, they have been included in the debt margin.

[171] Macquarie Bank, May 2002, p. 21.

arrangement and bank fees. The Commission acknowledges that these fees are likely to vary between each debt issue and also over time in line with market conditions. However, it is also recognised that a benchmark needs to be established in order to determine a reasonable allowance for a revenue calculation. According to financial markets a spread of five basis points each year represents an appropriate estimate of fees payable to a bank for the arrangement and distribution of debt. This benchmark is based on debt with a maturity of five years. The net present value of this fee is calculated and levied at the time of the arrangement of the debt.

Another cost that is often incurred is a dealer swap margin which is payable to the relevant financial institution.[172] The Commission considers that this is a valid cost given that debt providers traditionally provide their funding through a floating interest rate facility, but often require companies to enter into hedging arrangements to reduce the extent of interest rate risk.[173] The Commission understands that a benchmark swap margin is currently set at approximately three basis points per year on issued debt. This fee may be levied either as an upfront fee or as an annual margin.

There may also be other direct costs not charged by the arranger of the debt. These fees include advisory and legal fees, as well as agency costs incurred when obtaining a credit rating.[174] The Commission considers that it is not be appropriate to incorporate these costs in the revenue requirement. The Commission understands that the external legal and advisory costs are generally negligible for a company when raising debt. Further, credit rating costs are generally not required of debt providers. As noted by Macquarie Bank:

> If the project has obtained a credit rating, then Debt Providers will review the rating level and the rationale for the rating provided by the agency. However Debt Providers, particularly bank lenders, do not usually rely on this analysis. The majority of Debt Providers do not delegate their credit decision processes to the credit rating agencies.[175]

It may be argued that a credit rating is necessary for raising debt on capital markets. While this may be true, capital market raising represents an alternative to the norm of bank financing for infrastructure. A service provider will use this option (with its associated added costs) only if it is more efficient to do so. The Commission therefore considers that the firm should be responsible for any costs associated with improving on the benchmark, including credit agency costs.

In addition to the above mentioned costs, a service provider may choose to engage in ‘credit wrapping’ when raising debt. Credit wrapping allows a service provider to raise debt based on a AAA credit rating for a fee payable to a credit monoline.[176] By undertaking such an arrangement, a service provider may improve on the benchmark cost of debt and keep the benefits achieved. The Commission does not consider that an allowance for credit wrapping should be provided to service providers. Regulated businesses are given a benchmark payment to compensate for the cost of debt, and if a

[172] ibid., p. 21.

[173] ibid., pp. 16, 21.

[174] ibid., p. 21.

[175] ibid., p. 12.

[176] ibid., p. 9.

company is of the view that it can outperform this benchmark, then the costs (and benefits) associated with pursuing this strategy are the responsibility of the company. If the company were to be provided with these costs, then this would mean that users effectively incur a cost of debt which is in excess of the benchmark, but do not benefit from the payment. The inclusion of these costs will also distort price signals and may lead to inefficient behaviour by the service provider.

Following from the above, the Commission has determined that it is appropriate to provide a benchmark allowance for bank fees and dealer swap margin of a total of 8 basis points per year. The Commission proposes adding this 8 basis points to the debt margin and thus allowing the recovery of this cost through the WACC.

The Commission has estimated the impact of an additional eight basis points on the debt margin for GasNet. With a RAB of $493 million and a benchmark-gearing ratio of 60:40, the recovery of debt raising costs for GasNet in 2003 is approximately $237 000. A similar annual figure will be included for 2004-2007, although it will vary slightly each year in line with incremental annual changes to the RAB. This compares to the annual payment of $2 million per year proposed by GasNet for debt raising expenses.

Equity raising costs

As with debt raising costs, the Commission considers it is appropriate to provide an allowance for equity raising costs. Equity raising costs are required to be paid by an entity when it undertakes capital raising. These costs are paid to equity arrangers for services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors.[177]

A paper referred to by GasNet written by Lee et al provides benchmark numbers on the cost of raising equity in the US. According to this paper, the average gross spread payable to investment bankers for an initial public offering of equity is 6.03 per cent for amounts between US $100–199.9 million ($185-$370 million).[178] This gross spread does not include other direct costs such as legal, auditing, printing and registration costs. Lee et al estimate these costs to be 1.03 per cent. Thus, total direct costs are estimated to be 7.06 per cent for amounts raised between US $100-199.9 million.[179]

The Commission considers it appropriate to allow service providers to recover both gross spreads payable to investment banks and other direct costs associated with raising equity. It proposes to use the data collected by Lee et al given the apparent absence of recent Australian empirical data on this issue. Consequently, the Commission proposes to provide a recovery of 7.06 per cent of equity raised to GasNet for equity raising costs.[180]

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[177] Macquarie Bank, May 2002, p. 10.

[178] I Lee, S Lochhead, J Ritter, Q Zhao, ‘The Cost of Raising Capital’, *The Journal of Financial Research,* Spring 1996, p. 62.

[179] ibid., p. 62.

[180] It is considered that this benchmark number is appropriate for GasNet given that its regulated equity falls within the US$100-199.9 million range (A$185-370 million). The benchmark figure will vary from company to company depending on the level of equity held by the specific entity.

Given that equity only needs to be raised once by the company, it is appropriate to spread the equity raising cost over the life of the asset. The Commission proposes the recovery of this once-off cost through an annual allowance over the life of the asset (of 60 years in this instance) expressed as a percentage of equity. This has the advantage of increasing the allowance as the capital base increases, reflecting the additional capital raising costs that a benchmark firm would incur.

The Commission's calculations indicate that an annual allowance of 48 basis points of equity has the same NPV as the 7.06 per cent benchmark levied in the first year of the asset. With a RAB of $493 million and the assumed 60:40 gearing ratio, this is equivalent to approximately $948 000 in 2003 which would be recovered as an annual cash flow. This compares to the proposal put forward by GasNet for equity raising costs of $500 000 per year. The difference is the outcome of the use of a benchmark instead of company actuals, and the Commission's recognition of the time value of money when amortising equity raising costs over the life of the asset.

Proposed amendment 12

GasNet must amend section 3 of its revised access arrangement information to include an allowance for equity raising costs of 0.48 per cent of regulated equity, to be recovered as an annual non capital cost cash flow. It must also amend its revised access arrangement to exclude an allowance for debt raising costs in non capital expenditure cash flows and add 8 basis points to the debt margin for these costs.

6.2.2 K factor

Current access arrangement provisions

The access arrangement as it currently stands includes a provision for a K factor adjustment. If the average tariff achieved is different to the average benchmark tariff, future tariffs are adjusted to allow the under-recovery (over-recovery) to be recovered (paid back to users) in the next regulatory year. This does not affect GasNet's incentive to grow the market, as the average tariff is not affected by absolute changes in volumes – it is only affected by changes in the product mix.[181]

Schedule 5 of the Tariff Order sets out the details of the K factor adjustment as part of the transmission price control formulae. Schedule 5 also specifies a rebalancing control formula for individual tariffs. The current access arrangement provisions allow for an increase in individual tariffs by 1 per cent (above the CPI-X formula) per year.

The Commission must assess the proposed tariff adjustment towards the end of each calendar year. The new tariffs are implemented from 1 January of the subsequent year. As GasNet must propose its next tariff before full year performance is known, its calculations can be based on actual data for most of the year but include an estimate for the last part of the year. Differences between this estimate and actual performance are corrected as part the tariff adjustment for the subsequent year.

181 For example, if volume decreases in zones which are charged high tariffs and volumes increase in zones which charge lower tariffs, the overall volumes may not change but the total revenue will be less than before. The K factor is designed to compensate for this possibility.

GasNet proposal

During the first access arrangement period, GasNet experienced a decrease in volumes associated with high tariffed services at a greater rate than volumes associated with low tariff services. That is, differences between the forecast and actual product mixes resulted in a shortfall in average revenue. While the K factor adjustment allows for an increase in the maximum average tariff (above the CPI-X formula) in the year following such a shortfall, the current limitation on increases in individual tariffs of 1 per cent per year (above CPI-X) restricted the amount of the shortfall that GasNet could recover in the initial access arrangement period.[182]

GasNet proposes rolling forward the portion of the K factor shortfall which was unrecovered in the first access arrangement period. It estimates a total shortfall of $14 million (2002 dollar terms) which GasNet escalates for inclusion in the model in 2003. The 2002 dollar figure comprises the calculated estimated cumulative shortfall of $10 359 839 for 1998-2001 and an estimated additional K factor shortfall in 2002 of approximately $3.6 million.[183]

GasNet proposes maintaining the K factor adjustment mechanism for the second access arrangement period but amending the cap on individual tariffs. Schedule 4 of the revised access arrangement puts forward changes to the rebalancing control formula to allow recovery (pay back) in full of the calculated K factor in the year immediately subsequent to the under-recovery (over-recovery). Additionally, it is proposed in Schedule 4 that the rebalancing control formula be amended to allow rebalancing upwards by 2 per cent above CPI-X plus K factor adjustment, compared to 1 per cent above CPI-X in the current access arrangement provisions.[184]

Submissions

Origin states that it is not seeking a change to the general K factor approach, but considers that it is inappropriate to allow the K factor adjustment to occur without constraints. Origin notes a number of issues with the K factor proposal put forward by GasNet. One concern is that the K factor does not take into account the changes to a retailer’s aggregate load characteristics that may result from the implementation of full retail contestability. Origin adds that the proposed approach for the second access arrangement period transfers a substantial degree of risk to the users of the system. Furthermore, Origin highlights its concern that the K factor allows GasNet to achieve higher than forecast total revenues while applying for an increase in tariffs in the future as a consequence of the operation of the K factor adjustment.[185]

TXU is concerned that there is the potential for the GasNet proposal to generate price shocks through the additional ability to rebalance tariffs. TXU argues that the K factor recovery should be linked to an appropriate constraint on rebalancing tariffs that limits

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182 GasNet access arrangement information, 27 March 2002, p. 10.

183 At the 2001 annual tariff reset, the cumulative K factor recovery shortfall was estimated to be $11 053 909 in 2002 terms. It was estimated that the company would recover $694 070 of this through the maximum allowable increase in tariffs in 2002. This means that GasNet has an estimated cumulative K factor under-recovery of $10 359 839 (in 2002 dollars).

184 GasNet access arrangement, 27 March 2002, pp. 33- 38.

185 Origin submission, 17 May 2002, pp. 3-4.

the scope for individual tariff adjustment. Another concern is that the proposed price control formula shifts the risk of differences between changes in demand assumptions and actual demand from GasNet onto users, and does not recognise possible changes in load characteristics of retailers as the competitive market develops. TXU also states that it was unable to determine what incentives the K factor adjustment has on the behaviour of GasNet, and that the proposed price control formula allows GasNet to earn more than its revenue requirement for reasons outside of its control. It also comments that GasNet should either seek roll-in of the Southwest Pipeline, or propose a price control formula that separates the Southwest Pipeline tariffs from the rest of the PTS tariffs.[186]

BHP Billiton expressed the following concerns with the K factor approach:

- it may allow for windfall gains for GasNet through allowance for a K factor adjustment even at times of increasing volumes and revenues;
- there is potential under the K factor for cross-subsidies to be built into the tariff structure and thus the removal of cost reflectivity; and
- care needs to be taken with regard to the K factor adjustments relating to the Southwest Pipeline and the WTS.

To ameliorate these concerns, BHP Billiton proposes a different K factor mechanism. Under this model, each withdrawal and injection zone would be ring fenced, and a K factor correction would be calculated for each zone. However, BHP Billiton recognises that this approach may be impractical, and suggested as an alternative calculating a K factor adjustment for each injection zone and a single K factor calculated for all withdrawal zones.

BHP Billiton also notes that the K factor adjustment removes some risk from GasNet and places it with users. It considers that the WACC for GasNet should reflect this risk reduction. Further, in view of its concerns that this mechanism could lead to subsidisation, BHP Billiton requests that GasNet demonstrate the cost allocation method between zones and reveal the costs used to develop the tariffs in each zone.[187]

ACG recommends that a separate price control should operate in respect of the Southwest Pipeline assets, and that 'any K factor in the price control should be quarantined to future SWP tariffs.'[188] ACG also recommends that GasNet be required to establish a redundant capital policy that would require the value associated with the Southwest Pipeline assets to be written down to the extent necessary to permit the costs to be borne by users of the Southwest Pipeline.[189]

Pulse is concerned about the proposed increase in tariffs in the first year of the second access arrangement period, and suggests that this is in part a consequence of the lump sum claim for the K factor carryover. Pulse submits that the 'lump sums associated

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186 TXU submission, 31 May 2002, pp. 34-35.

187 BHP Billiton submission, 18 July 2002, pp. 2-4.

188 The Allens Consulting Group, *Implementation of incremental pricing of the Southwest Pipeline*, (ExxonMobil submission, 5 June 2002), p. 23.

189 ibid., p. 24.

with efficiency gains and K factor carryovers should be treated as annuities over the life of the second access arrangement.'[190]

Commission's considerations

The Commission considers that GasNet should be able to recover the shortfall it suffered due to limitations in the individual tariff rebalancing control during the first period through an allowance in its benchmark revenues for the second period. The Commission proposes to allow recovery of the estimated cumulative K factor shortfall for 1998-2001 in the benchmark revenues and the recovery of the estimated 2002 shortfall when it is known, as discussed below. The estimated cumulative shortfall for 1998-2001 is equal to $10 359 839 or $10 835 874 in 2003 dollar terms.[191]

As discussed above, the K factor adjustment relating to a specific year is made in two parts. First, the tariff implemented in January of the subsequent year includes an adjustment recognising actual performance for the first part of the year and expected performance for the remainder of the year. Second, differences between the estimate and actual performance are corrected as part of the tariff adjustment for the subsequent year.

Consistent with this approach, the Commission proposes that GasNet include an estimate relating to its 2002 performance as part of the annual tariff approval process at the end of 2002. This 2002 K factor estimate would be calculated by calculating the cumulative K factor for 1998-2002 and subtracting the cumulative recovery for 1998-2001 allowed in the benchmark revenues for this access arrangement period. Tariffs set in January 2003 will then be revised to reflect this 2002 K factor estimate, with the result that actual tariffs for 2003 would be different to those set out in the *Final Decision* document. Any difference that may occur between the 2002 K factor carryover estimate and actual performance would then be corrected as part of the tariff adjustment commencing in January 2004.

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[190] Pulse submission, 16 May 2002, p. 5.

[191] As noted, GasNet faces an estimated K factor shortfall of $10 359 839 in 2002 dollars terms. Under Schedule 5 of the Tariff Order, the value of K is adjusted for the time value of money from year to year by the equation (1+i). The variable i in this equation represents the Australian Financial Markets Association end of day swap reference rate at 30 September in the regulatory year, varied by the subtraction of 50 basis points where K is a negative value, and the addition of 50 basis points where K is a positive value. While the value of i cannot be determined until 30 September 2002, an estimate for i can be calculated using the 1 year swap rate current at 30 July 2002. Subtracting 50 basis points from the current swap rate of 5.095 per cent gives an i value of 4.595 per cent. Using this data, the estimated shortfall in the K factor carryover is calculated to be $10 835 874 in 2003. This will be recalculated using known 30 September figures in the Final Decision.

Proposed amendment 13

GasNet must amend section 3.5 of its revised access arrangement information so that the estimated K factor under-recovery to be recovered in benchmark revenues is $10 359 839 in 2002 dollars adjusted to 2003 dollars using the formula noted in schedule 5 of the Tariff Order. GasNet must also amend section 3.5 of its revised access arrangement information to state that annual tariffs set for 2003 will be adjusted to reflect the 2002 K factor carryover, which will be calculated at the annual tariff review process at the end of 2002.

The Commission agrees that the K factor mechanism should be maintained in the subsequent access arrangement period. It also agrees in principle with GasNet's proposal to change the rebalancing control formula for individual tariffs. The Commission recognises that the introduction of an allowance for the K factor in individual tariffs would expose users to increased tariff volatility during an access arrangement period. This contrasts with the current arrangements which effectively shield users from this volatility within an access arrangement period but exposes them to tariff shock at the start of a new access arrangement period. The Commission proposes to accept the introduction of this allowance. However, it considers that the proposed maximum increase for individual tariffs from 1 to 2 per cent above the average increase is unreasonable. The shift would give GasNet undue scope to rebalance tariffs during the access arrangement period, with the potential to substantially reduce the cost-reflectivity of tariffs established through the current revisions approval process.

Proposed amendment 14

GasNet must amend clause 4.9 of schedule 4 of its revised access arrangement so that the Maximum Price for each Transmission Tariff Component (MPTC) in 'step 3' can increase by only one per cent (0.01) above the MPTC in 'step 2'.

As noted above, a number of submissions raised additional concerns in relation to GasNet's proposal.

BHP Billiton and Origin expressed concern that in some instances GasNet may achieve higher than forecast total volumes and thus revenues, and still apply for a K factor adjustment if average revenues decrease.[192] The Commission notes that equally, GasNet could achieve lower than forecast volumes and still be required to pay back a K factor adjustment. The Commission considers that such an outcome is consistent with the operation of the K factor, and that no amendments should be made to prevent this result. The K factor mechanism is intended to address changes in average revenue (either positive or negative) independently of any changes in total volumes that may occur simultaneously.

Pulse commented on the contribution to the 38 per cent increase in tariffs between 2002 and 2003 made by the lump sum K factor, and suggested that this lump sum amount should be treated as annuity over the access arrangement period. The Commission

[192] BHP Billiton submission, 18 July 2002, p. 2; Origin submission 17 May 2002, p. 4.

notes that the K factor carryover is already proposed to be spread across the second period, and that the Commission proposes to maintain this approach and distribute the relevant K factor carryover using the tariff levelisation approach.

Another issue raised by BHP Billiton and TXU concerned the impact of the K factor on individual tariffs. In particular, BHP Billiton identified ‘a strong potential for cross subsidies to develop resulting from allocation of the gross adjustment’.[193] In order to remove this possibility, BHP Billiton suggested that each withdrawal and injection zone would be ring fenced, and that a K factor correction would be calculated for each zone. Alternatively, it suggested ring-fencing the five injection zones and bundling withdrawal components into one zone, and calculating a K factor for each injection zone and an single K factor for all withdrawal zones. ACG also proposed that costs associated with the Southwest Pipeline be quarantined.

The Commission acknowledges the concerns raised by BHP Billiton, TXU and ACG. The Commission considers that GasNet’s K factor proposal may potentially defeat the purpose of the economic feasibility test of the Code (section 8.16(b)). Under the economic feasibility test, a new facilities investment can only be included in the capital base if the anticipated revenue generated by the facility exceeds the cost of the investment. If volumes experienced on the new asset fall short of expected volumes once it is rolled into the asset base, then the asset would effectively not recover its costs. However, with a K factor mechanism, part of its costs could be recovered from users of other services. That is, customers from other zones would effectively cross-subsidise the cost of the new asset for outturn volumes being less than anticipated.

The Commission considers that it would be undesirable for the operation of the K factor adjustment to potentially override the cost reflective nature of the tariffs to apply after 2002. Consequently the application of the general K factor mechanism to new assets included under the economic feasibility test may not be appropriate given volume uncertainty and the potential for substantial cross-subsidisation.

The Commission has carefully assessed the alternative models suggested by BHP Billiton. It has also considered a simpler approach which would ring fence extensions to the PTS from the general K factor adjustment. For example, the Southwest Pipeline, the WTS, the Murray Valley Pipeline and any future extensions included under the section 8.16(b) test would be ring fenced.

It appears that each of these models would be likely to generate considerable complexity and uncertainty. The Commission is particularly concerned that users could be subject to substantial and frequent major tariff shocks. It is also concerned that additional complexity may reduce transparency. The Commission understands that users of the PTS already find the tariff structure complex. Further, as noted by GasNet, if investments such as the Southwest Pipeline were to be effectively quarantined, there would be some grounds for treating them as independent pipelines.[194]

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193 BHP Billiton submission, 18 July 2002, p. 3.

194 GasNet response to Commission, 16 July 2002, p. 8.

More fundamental is the question of whether these approaches would achieve the objective of quarantining costs and revenues to certain assets. In principle, where average revenues differ from expected average revenues, an individual K factor adjustment would be calculated and applied to each of these assets. This approach would need to be adopted both during and between access arrangement periods in order to achieve the objectives on an on-going basis. However, a sharing of costs would still occur at the scheduled review. This may be overcome by treating each of these assets as a stand-alone pipeline with a separate financial model. However, this would further complicate GasNet's regulatory arrangements. The Commission has not required this degree of complexity when approving other access arrangements. It is concerned that it would also increase GasNet's compliance costs (which would ultimately be borne by users).

Moreover, whenever there is a difference between the expected and actual product mix (or costs) within an access arrangement period, tariffs will move away from the level of cost reflectivity assumed when the access arrangement (or revised access arrangement) was approved. This will occur regardless of whether there is a K factor adjustment.

On balance, the Commission does not consider that it would be technically and commercially reasonable to require GasNet to isolate certain assets to the extent necessary to prevent the potential for cross-subsidisation.

The Commission's assessment of GasNet's proposed treatment of the Southwest Pipeline is at chapter 4.2.5.

6.2.3 Efficiency carryover

GasNet has proposed an allowance of $5.4 million in the second access arrangement period for first period efficiency gains. While the Commission acknowledges GasNet's belief that much of its first period efficiency gains were not sustainable, a comparison of historical data for that period against second period forecasts suggests that GasNet actually became less efficient, and should in principle be subject to a negative glide-path mechanism in the second period. The Commission considers that because of the uncertainty relating to the benefit sharing mechanism that GasNet was subject to at the start of the initial access arrangement period, it may be unreasonable to penalise GasNet in the second period for efficiency losses. Accordingly, the Commission considers that an efficiency carryover of zero in the second period for first period behaviour would be appropriate. This approach is discussed in detail in section 10.1.5 of this Draft Decision.

6.2.4 Asymmetric risk

GasNet has identified a number of specific risks that it considers to be asymmetric and should be recoverable. GasNet considers that these risks have the features of:

- asymmetry, that is the possible negative outcome of the event is greater than the possible positive outcome;
- insurance being difficult, if not impossible, to obtain at a commercial rate;
- investors being unable to diversify away the risk; and

- GasNet's likely economic income would be less than the target economic income because of these risks.[195]

GasNet states that it accepts the view that specific risks should not be reflected in the CAPM. Accordingly, it proposes to include an allowance for asymmetric risks in the cash flow to calculate total revenue and reference tariffs. The asymmetric risks identified by GasNet are shown in Table 6.4 below. These amounts increase with inflation over the period. Many of the annual allowances included in this table reflect an estimate of self insurance by Trowbridge Consulting.[196]

Table 6.4: Proposed asymmetric risk allowance, 2003

Risk	Allowance ($)
Property related risks	20 000
Deductibles in current insurance	140 000
Credit risk	252 000
Terrorist threat	65 000
Risk of stranding	75 000
Other	200 000
Total	752 000

Source: GasNet access arrangement information, 27 March 2002, p. 11.

BHP Billiton has expressed concern that the Trowbridge Consulting report remains confidential when it is likely to 'provide important information on such a significant issue'. Nevertheless, BHP Billiton notes that GasNet appears to be undertaking self insurance. It considers that these funds should be placed in a trust fund and not in general revenue.[197] In response, GasNet has stated:

> BHP Billiton's appears to suggest that the self-insurance costs should be treated as a form of indemnity fund rather than as a risk-weighted cash flow amount. GasNet considers that BHP's suggestion is an unwarranted interference in GasNet's management prerogatives.[198]

The Commission has agreed to GasNet's request for the Trowbridge Consulting report to remain confidential. Publication of the report may prejudice GasNet's dealings with insurance companies as it details the value of, and need for, various types of insurance.

As noted in its recent Draft Greenfields Guide, the Commission considers that the regulatory framework can address asymmetric risk (whether upside or downside) for transmission pipelines. In addition, the Commission notes that specific risks need to be

195 GasNet submission, 27 March 2002, schedule 4, pp. 28-29.

196 The Trowbridge Consulting report to GasNet has been provided to the Commission (as annexure 7 of GasNet's submission) on a confidential basis.

197 BHP Billiton submission, 21 June 2002, p. 23.

198 GasNet response to submissions, 24 July 2002, p. 12.

assessed separately for each access arrangement and factored into the business' cash flows rather than the cost of capital.[199]

In general, the Commission considers that:

> ... to adequately assess a proposal for self-insurance, in relation to prudency and validation of an appropriate premium, it would need to consider such matters as: a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums; confirmation of the board resolution to self-insure; and the relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance for.
>
> A regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring. In the event of future expenditure required as a result of an insurance event such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operations and maintenance element of the allowed tariffs and funded by users.[200]

GasNet has proposed to include an asymmetric risk allowance in the cash flow and has provided a report by Trowbridge Consulting in support of its claims. However, it has not provided explicit confirmation that the business will self-insure for certain identified risks and that future actual costs relating to these events will not be included in future regulatory cash flows. The Commission generally requires this assurance be provided by a resolution from the company's board of directors. However, in light of the amount of asymmetric cost allowance the Commission proposes to accept for GasNet, the Commission will accept the confirmation from the company in this instance. A resolution from the board would be required for a larger amount. Accordingly, an amendment to the proposed revised access arrangement is proposed.

Proposed amendment 15

GasNet must include in clause 4, reference tariff policy, of its revised access arrangement:

- explicit confirmation that the business will self-insure;
- details that clearly specify the self-insured risks consistent with this Draft Decision; and
- explicit confirmation that future actual costs relating to these identified events will not be included in future regulatory cash flows.

Property related risks

GasNet includes pipeline corrosion risk as part of its property related risks, which it states is excluded from its existing property insurance. It also includes bomb threat risks. Insurance policies of this nature generally cover losses due to payment of a ransom, other related expenses and loss of earnings.

The Commission would expect that the risk of pipeline corrosion is largely with GasNet and could be considered to be controllable. Inadequate levels of pipeline

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199 ACCC, *Draft greenfields guideline for natural gas transmission pipelines*, June 2002, pp. 12-13.

200 ibid., p. 16.

maintenance may lead to a greater likelihood of corrosion. GasNet is the party in the best position to determine the level of appropriate maintenance, the likelihood of pipeline corrosion and the financial consequences of its decision. Accordingly, the Commission proposes that allowances related to pipeline corrosion not be accepted.

The Commission understands that the remaining items included in this category are insurable but that GasNet does not hold insurance for them at this time. In effect, GasNet is proposing to self-insure for these events.

The Commission proposes to accept an amount of $10 000 per year for property related risks.

Deductibles in current insurance

Deductibles in current insurance reflect action on the part of GasNet to limit its insurance costs. This category includes the payment of an excess when a claim is made and the payment of claims above the insured amount. The corollary is a reduction in the amount paid in premiums to insurers which may be a prudent business practice to undertake.

The Commission understands that GasNet is required to maintain insurance for certain events pursuant to the SEA. The deductibles relevant for the various policies vary considerably.[201]

The Commission acknowledges that these considerations can constitute a legitimate expense. However, as with insurance premia, they are difficult to predict with accuracy. The Commission considers that the proposed amount of $140 000 per year should not be included in the cash flows in the manner proposed by GasNet. Instead, it considers that actual expenditure should be included in the calculation of the insurance pass through event. This reduces the uncertainty for GasNet as to whether the estimated allowance is sufficient (see section 3.2 of this Draft Decision).

Proposed amendment 16

GasNet must amend section 3.5 of its revised access arrangement information to exclude the $140 000 annual allowance for Deductibles in current insurance arrangements from the cash flows.

Credit risk

The allowance for credit risk reflects a risk of insurers and counter parties defaulting. First, in respect to insurers' credit risk, GasNet is seeking to self-insure in respect of the loss of premium paid in respect to the unexpired period of cover upon the bankruptcy of the insurers and with regard to an insurer being unable to honour an insurance policy. Trowbridge Consulting has estimated an annual premium for these events. The Commission has concluded that an allowance of this in GasNet's cash flows is not unreasonable.

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[201] GasNet response to Commission, 23 July 2002.

The second component of the credit risk allowance relates to counter party credit risk, that is, the risk that the Victorian gas retailers fail to pay GasNet amounts owing in relation to regulated transmission charges. GasNet has based the proposed allowance on a quotation for an insurance policy. Similar amounts were also proposed by the gas distribution businesses which the ESC assessed in some detail. The ESC determined that the expected revenue losses arising from counter party bankruptcy were overstated in light of the terms and conditions relating to the distributors' reference services; the average default rate of BBB rated firms and the recovery rate of debt; and the credit ratings of the firms in question. It concluded that 'the expected loss associated by retailer default would be close to $10 000'.[202]

The Commission considers that the adjustments made to the counter party credit risk claims by the ESC noted above are also relevant to GasNet's proposals. It notes that the revenues subject to this risk are greater for the distribution businesses than GasNet. A proportional adjustment to the annual allowance proposed by GasNet could be made.

On balance, the Commission proposes to accept an annual allowance in total of $12 000 for GasNet's total credit risk**.**

Terrorist threat

GasNet has stated that terrorist sabotage cannot be insured. It comments that US utilities have been threatened recently. While Trowbridge Consulting has not quantified this risk, GasNet has estimated a premium of $65 000 based on a value of aboveground assets of $140 million and a one in five hundred event.

It would appear that the likelihood of terrorist sabotage for GasNet is very small. The indication from Trowbridge Consulting is that estimates of an insurance premium would vary significantly and be subjective. Without the ability to ensure that the proposed cost is prudent the Commission is inclined not to include this cost in the calculation of reference tariffs. In addition, the Commission does not regard GasNet's likelihood of becoming subject to this event as being different to other Australian businesses as a whole. To the extent that all Australian businesses face a terrorist threat, the market will accommodate the related risk. Accordingly, the Commission proposes to exclude the $65 000 annual allowance from GasNet's proposed costs.

Risk of stranding

GasNet considers that its laterals are subject to the risk of bypass, or stranding. As an example, it notes that the proposed Iona to Adelaide pipeline would pass towns currently supplied by the WTS. In this case, GasNet has proposed a prudent discount for these users. In addition, GasNet suggests that the current redundant capital policy would cause partial and wholly redundant assets to be removed from its regulatory capital base. Based on a one per cent probability of five per cent of laterals being bypassed, GasNet has estimated a self insurance premium of $75 000 per year.

In assessing any redundant capital policy the Commission is required, pursuant to section 8.27 of the Code, to 'take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have'. The Commission considered this

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[202] ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 275.

factor when it assessed the access arrangement for GasNet's predecessor in 1998. It has also been included in its current assessment of the redundant capital policy. Accordingly, it is not appropriate to make any further adjustment, whether to CAPM or the cash flows, for this policy.

GasNet has referred to the possible bypass of part of the WTS. As noted above, GasNet has proposed a prudent discount for the relevant WTS users. The Commission considers this course of action is appropriate for a potential bypass event. As noted in the DRP, the Commission also considers an adjustment of the asset's depreciation schedule an appropriate response.[203] Accordingly, any additional adjustment to the cash flows, as proposed by GasNet, does not appear necessary or appropriate. In general, the Commission does not consider the risk of stranded assets is significant for GasNet. Even if this were the case, the Commission would expect GasNet to make use of its proposed ability to offer prudent discounts and the flexibility of its depreciation schedules. On balance, the Commission does not consider the addition of $75 000 per year to GasNet's cash flows as appropriate and proposes to exclude this cost.

Other risks

GasNet notes that a number of other asymmetric risks have been identified by Trowbridge Consulting totalling $200 000 per year. No further information is available to interested parties.[204] This treatment of 'other risks' has attracted comment from interested parties. However, the Commission proposes to accept GasNet's confidentiality claims in this area. Consequently, the Commission's assessment in this section is expressed in general terms.

GasNet is liable for uplift payments to other market participants if it fails to meet its obligations under the SEA. The liability is limited to the lower of $20/GJ or $1 million per year. Under GasNet's proposal, the risks attached to this allowance would be shifted from GasNet to users. GasNet's reference tariffs are based on the costs associated with maintaining the PTS to the level required under the SEA. In effect, users would be paying twice to have the PTS operate as specified by the SEA. This would be an unsatisfactory situation. Accordingly, the Commission proposes to exclude the proposed cost.

GasNet proposes an allowance for partially stranded assets. The impact of stranded assets on GasNet is illustrated by unforecast supply from Yolla. The appropriate regulatory approach to stranded assets (in part or in total) has been noted above in relation to the WTS. GasNet's concern with regard to the potential impact of the development of the Yolla fields in particular is addressed by the Commission's proposal to include related flows in the demand forecasts for the second access arrangement period.

GasNet has also proposed an allowance for key person risk. Insurance policies are available in relation to the risk of business disruption costs arising from the sudden departure of key staff and the cost of finding a suitable replacement. The ESC has recently considered self insurance for the loss and replacement of key staff of the gas

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203 ACCC, DRP, p. 62.

204 GasNet submission, 27 March 2002, schedule 4, p. 32.

distribution businesses. It stated it ‘would find it difficult to accept that there would be any significant disruption to earnings – revenue would continue to flow, and procedures for maintaining assets would continue to be followed regardless’.[205]

The Commission agrees with the ESC’s view and notes that the only clear activity that may suffer disruption would be market development, a relatively minor aspect of a transmission company’s business. It also notes that GasNet was without a Chief Financial Officer for a considerable period and has only recently filled this position. The Commission has not been made aware of any disruption to GasNet’s business operations as a result of this vacancy. In addition, the Commission does not consider that GasNet is alone in facing the possibility that key staff may leave the business. This would be a ‘risk’ faced by all businesses.

On balance, the Commission does not consider that the claimed self insurance cost is appropriate. Accordingly, the Commission proposes to exclude the proposed annual cost of key person risk from GasNet’s cash flows.

An additional self insurance item relates to wrongful acts in relation to employment practices. This includes sums for damages, settlements and other costs relating to actions of harassment, unlawful discrimination and breaches of privacy. The Commission does not consider that this event is specific to GasNet. All businesses must comply with the relevant legislation on these matters. The Commission does not consider it appropriate to provide an allowance to GasNet to self-insure for this event. Accordingly, it does not accept the inclusion of this allowance in GasNet’s cash flows.

Conclusion

The Commission considers that, in principle, it would be appropriate for costs associated with asymmetric risks to be included in the calculation of GasNet’s cash flows when determining benchmark revenue. However, it has concluded that a number of GasNet’s claims are unjustified and that an appropriate allowance would be $22 000 a year in total (in respect of property related and credit risk).

Proposed amendment 17

GasNet must amend clause 3.5 of its revised access arrangement information so that the allowance for asymmetric risks is $22 000 (in 2003 dollars) a year for each year of the access arrangement period.

6.2.5 Working capital

In the first access arrangement period, tariffs were based on benchmark revenue which included a return on working capital. This is the amount of capital a firm requires to operate given that expenses occur before revenue is received. GasNet has not proposed a return on this working capital for the second access arrangement period.

Instead, GasNet proposes that a return be included in the cash flow calculations for the cost of maintaining linepack and inventories (which together it labels as working

205 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 276.

capital). GasNet is claiming $0.3 million a year as the result of applying the nominal WACC to its investment in these two items.[206]

The Commission considers that an inventory of spare parts and linepack are assets which form part of the capital base of the firm. It notes that the GHD valuation in 1997 included values for each of these items. The Commission concludes that linepack and spare parts inventories do not form part of the generally accepted definition of 'working capital' and instead form part of the capital base of the firm.

The Commission understands that linepack and spare parts inventories would have been included in the purchase price when GasNet's predecessor, GPU Inc, bought the business from the Victorian Government. The initial capital base had already been established at that time. As noted in section 4.1.5, the Commission does not consider it either appropriate or possible for it to redetermine the value of the initial capital base. Consequently, the Commission does not have the discretion to add to the capital base a value for linepack and inventories. To include a return on these items through the cash flow calculations would have the same effect as adding their value to the capital base. Consequently, the Commission proposes not to accept a return on linepack and inventories in the cash flow calculations.

Proposed amendment 18

GasNet must amend section 3.5 of its revised access arrangement information to remove the proposed allowance for working capital from its revenue calculations.

6.3 Capital expenditure

6.3.1 Code requirements

Pursuant to section 8.20 of the Code, reference tariffs may be determined based on forecast new facilities investment for the forthcoming access arrangement period if it is reasonably expected to pass the requirements of section 8.16 of the Code when the investment is forecast to occur.

If the regulator agrees to this approach, the Code (section 8.21) states that this need not imply that the new facilities investment in question will meet the requirements of section 8.16 when the relevant revision to the access arrangement is assessed. However, the regulator may make a binding decision that forecast new facilities investment will satisfy the Code's requirements and be included in the capital base through a future revisions application. Any application seeking such a decision from the regulator must be treated as if it was an application to revise the access arrangement in accordance with section 2.28 of the Code.

In addition, section 8.22 of the Code requires the reference tariff policy to state, or the regulator to require, how new facilities investment is to be determined when establishing the capital base for a new access arrangement period in accordance with

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[206] GasNet access arrangement information, 27 March 2002, pp. 9-10.

section 8.9 of the Code. This includes whether (and how) the capital base is to be adjusted when actual new facilities investment differs from forecast new facilities investment.

6.3.2 Current access arrangement provisions

GasNet's current policy relating to new facilities investment is set out in clause 5.3.3 of both the PTS and WTS access arrangements. It states that GasNet's extensions and expansions policies (see section 11.3 of this Draft Decision) explain how new facilities investment will affect reference tariffs.

The access arrangement information for the PTS and the WTS identifies a number of capital projects that were forecast to occur within the initial access arrangement period. A total of $56.3 million was forecast.[207] The most significant item was the Brooklyn loop with a forecast cost of $27.15 million.[208] Other projects included compressor automation and general maintenance capital expenditure.

These projects were included in the calculation of revenues and reference tariffs for 1998-2002 on the basis that they were likely to satisfy the requirements of section 8.16 of the Code. However, the Commission did not determine whether the section 8.16 criteria were satisfied at that time. This assessment would occur either at the time the investments took place or after the expenditure had been undertaken. The assessment of actual capital expenditure for the initial access arrangement period is provided in chapter 4 of this Draft Decision.

6.3.3 GasNet proposal

GasNet states that its proposed reference tariffs have been calculated on the basis of forecast capital expenditure that is, in its view, reasonably expected to pass the requirements of section 8.16 of the Code. GasNet notes that it may submit revisions to the access arrangement within the anticipated access arrangement period in relation to other new facilities investments that satisfy the requirements of section 8.16 of the Code.

As permitted by section 8.18 of the Code, GasNet states in its proposed reference tariff policy that it may carry out new facilities investment that does not meet the requirements of section 8.16 of the Code. If 'speculative investments' are undertaken by GasNet then, as outlined in the Code, the recoverable portion may be added to the capital base and the balance included in a speculative investment fund for possible future inclusion into the capital base.[209]

GasNet has proposed a number of capital projects for the forthcoming access arrangement period. These are outlined in the table below.

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[207] TPA access arrangement information, 30 November 1998, p. 13.

[208] GasNet submission, 27 March 2002, p. 38.

[209] GasNet access arrangement, 27 March 2002, pp. 5-6.

Table 6.5 Proposed forecast capital expenditure, 2003 to 2007

	$ million[a]					
	2003	**2004**	**2005**	**2006**	**2007**	**Total**
Brooklyn loop					20.70	20.70
Gooding compressor			6.49	8.13	7.95	20.30
Lurgi pipeline	2.05	2.10	1.55	5.83	5.97	16.0
City gates		2.36	2.53	4.41		8.31
Wollert compressor		1.50	1.82			2.70
Service lines	1.54	1.58	1.62	1.66	1.70	7.50
Maintenance	1.90	1.43	0.51	0.59	1.12	6.50
Total	5.49	8.97	14.52	20.62	37.44	

Source: GasNet access arrangement, 27 March 2002, pp. 5-6 and access arrangement information, 27 March 2002, p. 12.
Note: (a) All in 2002 dollars for years ending 30 June.

6.3.4 Submissions

The Commission received a number of broad comments in regard to the forecast capital expenditure for the forthcoming access arrangement period. ENERGEX expressed concern about the overall size of the forecast capital expenditure and raised the possibility of goldplating assets.[210] BHP Billiton considered that no quantitative analysis has been provided by GasNet to support the forecast capital expenditure. It stated that while users expect the pipeline system to be improved, GasNet had not provided any cost-benefit analysis in regard to the resources that it expects to employ.[211] Similarly, TXU considered that GasNet had not provided enough information to allow any detailed comment but it did suggest that VENCorp could comment on the proposals consistency with its annual planning review.[212] In contrast, Origin accepted that ‘the proposed forecast capital expenditure is consistent with reasonable and prudent practice’.[213]

More specific comments were also received. EnergyAdvice suggested that the forecast expenditure relating to the Brooklyn loop and the Gooding compressor should be allocated to peak reference tariffs. This is because, in EnergyAdvice’s view, these assets would only be used in winter and accordingly, winter users of the pipeline system should pay for these facilities.[214]

6.3.5 Commission’s considerations

The Brooklyn loop was included in the reference tariff calculations for the first access arrangement period. At the time, Transmission Pipelines Australia Pty Ltd (TPA)

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210 ENERGEX submission, 9 May 2002, p. 4.

211 BHP Billiton submission, 17 May 2002, p. 13.

212 TXU submission, 31 May 2002, p. 31.

213 Origin submission, 17 May 2002, p. 6.

214 EnergyAdvice submission, 30 May 2002, p. 8.

expected that forecast peak demand would not be satisfied by gas shipped from Longford after 2000. Accordingly, the Brooklyn loop was proposed to increase the capacity of the Brooklyn to Corio pipeline and allow gas to be supplied from the WUGS facility.

Although it was claimed that incremental revenue of at least $5 million exceeded the expected annual cost of $4 million, the Commission did not consider that the project would be likely to pass the economic feasibility test of section 8.16 of the Victorian Code. However, it did agree that system-wide benefits may arise from the project. The forecast cost of the Brooklyn loop project was included in the reference tariff calculations for 1998 to 2002.[215]

The Brooklyn loop project was not undertaken during the initial access arrangement period. GasNet now forecasts that it will be undertaken in 2007.

The key determinant for this project is the demand forecasts. The VENCorp demand forecasts for 2002 to 2006 do not unambiguously support augmentation of the Brooklyn loop in that period. Nonetheless, GasNet considers that augmentation is required in 2007. The balance between forecast demand and available capacity is close.

The demand forecasts used by GasNet do not include any gas expected to be sourced from the Yolla field. As discussed further in chapter 7 of this Draft Decision the Commission considers that flows from Yolla should be included in the forecast demand figures for the forthcoming access arrangement period.

As a result of including this gas source, the flows on the Southwest Pipeline will differ to those proposed by GasNet. This is discussed in chapter 4 of this Draft Decision. The adjusted forecast demand information does not support the need for the proposed Brooklyn loop project in 2007.

The Commission also notes that the inclusion of the cost of this project in the forecast capital expenditure for the initial access arrangement period resulted in GasNet obtaining benchmark revenue based on a return on that forecast capital expenditure during that period. The Commission does not ‘clawback’ revenues obtained in this manner. In fact, the ability to retain the additional revenue from unused forecast capital expenditure provides an incentive for GasNet to only undertake appropriate and efficient capital projects as they are required.

The Commission notes that, although investment in the Brooklyn loop has been forecast by GasNet to occur in 2007, it has not included this projected expenditure in its models to calculate revenues and reference tariffs for the new access arrangement period.

On balance, the Commission does not consider it appropriate to include forecast capital expenditure relating to the Brooklyn loop in the revised access arrangement. Accordingly, an amendment to the access arrangement is proposed.

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215 ACCC, 1998 Final Decision, pp. 86-87.

Proposed amendment 19

GasNet must amend section 3.6 of its revised access arrangement information to exclude any forecast expenditure relating to the Brooklyn loop from the calculation of tariffs.

The Commission accepts that it is likely that the Gooding compressor will need to be substantially refurbished in the near future in order to maintain the integrity and contacted capacity of services. The cost could be expected to be a substantial portion of, but not exceed that, of a new compressor station of similar size. The Commission understands that a replacement station may cost between $30 and $35 million (in 2002 dollars). The Commission's assessment is that the proposed cost of the project is not unreasonable. It proposes to accept the forecast capital expenditure for the purpose of determining future reference tariffs.

The Lurgi pipeline was constructed in 1956 and is the oldest segment of the PTS. GasNet proposes a two stage process in refurbishing the pipeline in order to maintain the safety, integrity and contacted capacity of services. First, some preliminary work and pigging would be undertaken. The work on the second stage would depend on the results of the pigging but would require the repair of minor defects at the minimum. However, partial modification of the pipeline or major enhancements may also be required in stage two.

Stage one is costed by GasNet at a total of $5.70 million over 2002-2003 to 2004-2005. On the basis of a study by the Commission's technical consultant it is of the view that these estimates are reasonable. It accepts GasNet's proposal for work to be undertaken in this area. The Commission proposes to accept inclusion of the first stage of the Lurgi pipeline project in the forecast capital expenditure for 2003 to 2007.

However, there appears to be considerable uncertainty regarding the most appropriate course of action for the second stage of the project. In acknowledging this uncertainty, GasNet has proposed that the forecast capital expenditure in 2005-2006 and 2006-2007 should include an average of the estimated cost of the options identified (a total of $13.35 million in nominal dollars).

In view of the uncertainty surrounding the proposed work and the range of cost estimates provided by GasNet, the Commission is unable to form an opinion on whether the second stage of the project would be reasonably likely to satisfy the requirements of section 8.16 of the Code. Accordingly, the Commission considers that it would not be appropriate to include any cost estimates relating to stage two of the Lurgi pipeline project in the calculation of tariffs for the second access arrangement period at this time. An amendment to this effect is proposed.

Proposed amendment 20

GasNet must amend section 3.6 of its revised access arrangement information to exclude any forecast expenditure relating to stage two of the proposed Lurgi pipeline rehabilitation project from the calculation of tariffs.

If this work does proceed, GasNet is able to seek a binding section 8.16 assessment by the Commission at that time pursuant to section 8.21 of the Code.

GasNet has identified a number of city gates in the PTS which it considers require upgrading during the next access arrangement period. This upgrading would include the installation of heaters at the Dandenong, Wollert and Tyers city gates. In total $9.29 million is forecast to be spent between 2003-2004 and 2005-2006. The Commission is satisfied that the work proposed is reasonably expected to meet the requirements of section 8.16 on the basis that it is necessary to maintain the safety, integrity or contracted capacity of services and that the forecast costs, which have been based on previous actual costs, do not appear to be unreasonable. Accordingly, the Commission proposes to accept the forecast expenditure relating to the improvement of the city gates in the calculation of the reference tariff for the revised access arrangement.

GasNet also plans to upgrade the compressor station at Wollert over two years, 2003-2004 and 2004-2005. This is expected to cost a total of $3.32 million. Minor capital expenditure of $5.56 million over the five year period is also planned. The Commission notes that this represents approximately 0.2 per cent of the ORC of the PTS and is comparable with similar expenditures for other transmission pipelines. The Commission is satisfied that both these expenditures (the Wollert compressor and the maintenance) are also reasonably expected to meet the requirements of section 8.16 and should be included in the calculation of the reference tariff for the revised access arrangement.

The Commission notes GasNet's proposal to include a forecast of $1.5 million per year (in 2002 dollars) for three possible service lines over the forthcoming access arrangement period. However, GasNet has also proposed to alter the extensions and expansions policy to allow service lines to not be included automatically in its access arrangement. As discussed in section 11.3 of this Draft Decision, the Commission has proposed to accept this revision to the access arrangement. Given the uncertainty as to whether these investments would be covered by GasNet's access arrangement, the Commission does not regard it as reasonable to include the forecast expenditure for service lines in the calculation of the reference tariffs for the second access arrangement period. However, if these investments are covered by the access arrangement they will be included in GasNet's asset base (subject to the provisions of section 8.16 of the Code). Accordingly, the Commission proposes the following amendment.

Proposed amendment 21

GasNet must amend section 3.6 of its revised access arrangement information to exclude forecast capital expenditure relating to service lines for 2002 to 2007 from the calculation of tariffs.

6.4 Depreciation

6.4.1 Code requirements

A service provider must establish a depreciation schedule for the assets that are included in the capital base. This is to consist of a number of schedules for each asset or group of assets. Pursuant to section 8.33 of the Code, under the Cost of Service approach used for the PTS, the depreciation schedule must result in:

- reference tariffs that change over time consistent with the efficient growth of the market for the reference service. This may include a substantial portion of depreciation taking place in future periods, particularly where reference tariffs have been set on the assumption of significant market growth;
- depreciation occurring over the economic life of the assets with progressive adjustments where appropriate to reflect changes in economic lives of the assets; and
- the asset being depreciated only once so that total depreciation is equivalent to the valuation of the asset at the time it was when initially incorporated in the capital base (subject to an adjustment for inflation, where appropriate).

Pursuant to section 8.5A of the Code depreciation may be expressed on a nominal basis, a real basis or in any other manner that deals with the effect of inflation provided that it is specified in the access arrangement, applied consistently and approved by the regulator.

6.4.2 Current access arrangement provisions

Reference tariffs for the current access arrangement period have been determined using real straight line depreciation on the basis of standard asset lives. In accordance with the current cost accounting approach adopted by the service provider, depreciation costs are adjusted to reflect the revaluation of assets due to inflation. The Commission stated that it accepted this approach as it resulted in fairly level tariffs over time.[216]

To calculate depreciation for the pipeline it was assumed that the economic life of the Longford pipeline concluded in 2030 and that of the other pipeline assets concluded in 2033. That is, at the time of the 1998 Final Decision, the assets had a remaining economic life of 32 and 35 years respectively.

6.4.3 GasNet proposal

GasNet proposes to retain real straight line depreciation with the exception of the Southwest Pipeline.[217] As provided by section 8.33(c) of the Code, GasNet has reviewed the basis of the economic lives of the assets with respect to recent estimates of gas reserves and other events.

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216 ibid., p. 45.

217 The Southwest Pipeline depreciation allowance will be levelised over the first 20 years. GasNet access arrangement information, 27 March 2002, p. 6.

GasNet commissioned Saturn Resources to review and update the analysis of asset lives it conducted prior to approval of the access arrangements. The current report considered the impact of gas reserves, bypass risk, rezoning and forced relocations, and unexpected and unspecified factors. These factors were used to adjust the remaining technical lives of the asset groups, resulting in remaining economic lives of the assets. Following from the Saturn Resources report GasNet has adjusted the expected end of life of the Longford pipeline from 2030 to 2023. In addition, it proposes that the life of the Southwest Pipeline concludes in 2052. An end of life of 2033 is still regarded as appropriate for the remaining pipeline assets.

As a result, the depreciation schedule for the forthcoming access arrangement period is provided in Table 6.6 below.

Table 6.6: Proposed annual depreciation allowances, 2003 to 2007

	$ million[a]				
	2003	**2004**	**2005**	**2006**	**2007**
Pipelines	14.45	15.04	15.65	16.40	17.33
Compressors	4.24	4.50	4.95	4.99	4.51
System control facilities	0.90	0.94	1.10	1.30	1.37
Odourisation	0.01	0.01	0.01	0.01	0.02
Gas quality	0.02	0.02	0.02	0.02	0.02
General land and building	0.18	0.18	0.19	0.19	0.19
Other	0.27	0.26	0.23	0.19	0.17
Total	20.10	21.00	22.20	23.10	23.60

Source: GasNet, Erratum, 19 July 2002.
Note: (a) All in nominal dollars.

As noted above, GasNet proposes a remaining economic life of 50 years for the Southwest Pipeline, ending in 2052. This reflects 'the fact that the Southwest Pipeline is a new pipeline in competition with other gas injection pipelines, and that a reasonable tariff is required in order to encourage growth on the pipeline'. In addition, GasNet proposes to levelise the revenue requirement for the Southwest Pipeline for the initial 20 years of the pipeline's life. As a result, the depreciation allowance for the Southwest Pipeline will be negative over the first period.[218] GasNet notes that the anticipated life of the Southwest Pipeline was not reduced in light of the anticipated depletion of the Otway Basin. It considers that the Southwest Pipeline will have an on-going value to the system as it is connected to the WUGS.[219]

Saturn Resources considers that the remaining life of the Longford-Melbourne pipeline is largely dependent on the reserves of the Gippsland Basin. Saturn notes the basin has relatively large reserves over the next 20 years. However, it will supply Victoria, NSW and Tasmania over that period. Saturn estimates that the remaining life of reserves is

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218 GasNet submission, 27 March 2002, schedule 5, p. 52.

219 GasNet response to submissions, 12 June 2002, p. 19.

approximately 18 years. However, this is offset in part by the possibility that the pipeline will be used for reverse flows of gas sourced from other basins. On balance, Saturn concludes that the remaining economic life of the Longford pipeline is 23 years with expiry in 2024.[220]

6.4.4 Submissions

Origin does not consider that there is sufficient information available to support the proposed change in the asset life for the Longford pipeline. It considers that the basic assumptions that were originally used to establish the asset's life have not changed and that new sources of gas will not have a substantial impact on the economic life of the pipeline.[221]

TXU has also commented on the Longford pipeline depreciation, suggesting that it should remain as it is. It notes that Esso-BHP has recently embarked on the largest survey of Bass Strait undertaken with the possibility that the earliest new discovery could start between 2006-2009.[222]

BHP Billiton considers that the depreciation rate for Longford should be at least what was established for the initial access arrangement period. It suggests that the proposal to depreciate the Longford pipeline faster than the Southwest Pipeline should be rejected. BHP Billiton regards the economic life of the Southwest Pipeline to be limited by the reserves of the Otway Basin and accordingly suggests that the Southwest Pipeline will have a relatively short life.[223]

Amcor and PaperlinX also note that the 'more rapid depreciation adds costs onto Longford related assets and reduces that relative costs of SWP assets'. In addition, 'the Saturn report ignores undiscovered Gippsland reserves in its economic evaluation'. Amcor and PaperlinX suggest that the following should be considered in relation to depreciation: the expectation of higher reserves for the Gippsland Basin leading to the EGP and Longford to Tasmania pipelines; the substantial exploration recently announced by Esso-BHP Billiton; and the current capacity of the EGP.[224]

In particular reference to the proposed depreciation schedule for the Southwest Pipeline, Esso has suggested that the economic life of the Southwest Pipeline has been determined with the aim of reducing the tariff to apply to that asset. It notes that 'It would appear somewhat unusual to determine the economic life of an asset on the basis of the desired tariff profile'.[225]

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220 GasNet submission, 27 March 2002, annexure 6, pp. 33-40.

221 Origin submission, 17 May 2002, p. 5.

222 TXU submission, 31 May 2002, pp. 28-29.

223 BHP Billiton submission, 21 June 2002, pp. 14-15; Amcor and PaperlinX submission, 24 June 2002, p. 11.

224 Amcor and PaperlinX submission, 24 June 2002, p. 11.

225 ExxonMobil submission, 5 June 2002, p. 26.

6.4.5 Commission's considerations

The Commission agrees with GasNet that retention of real straight line depreciation for the majority of assets included in the capital base is appropriate for the forthcoming access arrangement period.

As outlined above, GasNet has proposed to reduce the remaining economic life for the Longford to Pakenham pipeline on the basis that reserves in the Gippsland Basin will deplete significantly as it supplies Victoria, NSW and Tasmania over the next 20 years. This has attracted comment from a number of interested parties, all of whom do not agree with GasNet's proposal.

It is acknowledged that the Gippsland Basin will be used to supply gas into Victoria, NSW and Tasmania in the future. While this scenario may suggest an increased rate of depletion of reserves, Esso-BHP Billiton recently announced the commencement of an extensive study of Bass Strait for natural gas. The seismic survey is expected to cost approximately $60 million and will be followed by a two year drilling program costing approximately $250 million.[226]

In a subsequent submission, BHP Billiton reviews the Saturn report as well as other various sources of information regarding reserves and the supply-demand balance in south east Australia. In particular, it notes that gas producers tend to understate reserves for a variety of commercial reasons and that historically 'gas reserves have increased or matched supply even when growth in the demand for the gas increases'. BHP Billiton concludes:

> There is no doubt that there is significant imprecision in forecasting gas demand and gas reserves, but the assumptions underlying the Saturn report would seem to overstate the expected demand for gas in the eastern States, and at the same time, understate the potential reserves of natural gas to meet demand in the southeastern States.[227]

The Commission notes that GasNet has not proposed a matched reduction in the expected lives of its withdrawal pipelines. Similarly, the Victorian distribution businesses have not in their current revisions proposed a reduction in the relevant cut-off date of 2050 established in 1998 to reflect 'the future availability and use of natural gas reserves'.[228]

The impact of moving the end date of the Longford pipeline's economic life is that current users of the PTS would face increased tariffs to recover the additional revenue required by GasNet. While this additional revenue requirement is significant in total it would be spread over all users, resulting in a small increase for each user.

The Commission generally considers that asset owners would be in the best position to determine the appropriate effective life and depreciation profile for its assets. However, in this case it is concerned that the reduced life for the Longford to Pakenham pipeline would not reflect the likely life of the Gippsland Basin reserves and

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226 'Banking on a new boom in Bass Strait' *Australian Financial Review*, 8 April 2002, p. 14.

227 BHP Billiton submission, 18 July 2002, p. 9.

228 ORG, *Final Decision: Victorian gas distribution access arrangements*, October 1998, p. 66.

would be inconsistent with the expected lives of the withdrawal pipelines and distribution systems dependant on it.

On balance, the Commission considers it would be inappropriate to bring forward the end date of the Longford pipeline life by seven years to 2023 (from 2030). Accordingly, the Commission proposes the amendment below.

Proposed amendment 22

GasNet must amend section 3.3 of its revised access arrangement information to retain the current depreciation schedule for the Longford pipeline with a remaining economic life ending in 2030.

GasNet has proposed a remaining economic life of 50 years (ending in 2052) for the Southwest Pipeline. However, BHP Billiton has suggested that the Southwest Pipeline will have a relatively short economic life. The Southwest Pipeline may be predominantly used for the transportation of Otway Basin gas in the short to medium term. However, further development of the Otway Basin may arise in the future extending the life of the basin.

In addition, and as suggested by GasNet, the future development of the gas market in south east Australia may call on greater use of the WUGS (and consequently the Southwest Pipeline) than is presently anticipated. It also acknowledges, as noted by Esso, that a long remaining economic life for the Southwest Pipeline reduces the depreciation allowance to be included in the revenue calculations and allows a lower tariff. This may be appropriate for a relatively new pipeline that is yet to establish its market.

On balance, the Commission proposes to accept the proposed remaining economic life for the Southwest Pipeline of 50 years ending in 2052.

The remaining assets of the PTS have been allocated an economic depreciation of 30 years ending in 2033. As in the first access arrangement period, this results from an averaging of the remaining assets that have a variety of remaining lives. The Commission notes that this results in the bulk of the PTS with a different remaining economic life than the Southwest Pipeline. However, the uncertainties surrounding the market in the future do not support altering the economic life of the PTS at present. Accordingly, the Commission proposes to accept GasNet's continued use of the economic life ending in 2003 for the remaining portion of the PTS to calculate the depreciation schedule.

6.5 Inflation

6.5.1 Code requirements

Section 8.5A of the Code provides that the amount of total revenue can be determined under either a nominal or real approach or 'on any other basis in dealing with the effects of inflation' provided that it is specified in the access arrangement, approved by the regulator, and applied consistently.

6.5.2 Current access arrangement provisions

The reference tariff methodology for the initial access arrangement period uses a real framework. In 1998 an expected inflation rate of 2.5 per cent was used to calculate the expected revenues over the access arrangement period. An expected average tariff path was also developed on the same basis. The methodology provides for actual tariffs to be calculated annually with the actual inflation rate for the preceding 12 months. Similarly, at the conclusion of the initial access arrangement period, the capital base is to be adjusted for actual inflation.

6.5.3 GasNet proposal

GasNet has applied actual inflation to the capital base for the initial access arrangement period as anticipated in the current provisions of the access arrangement.[229]

GasNet has proposed to continue with a real rate of return methodology. GasNet has used an annual inflation rate of 2.5 per cent to escalate the capital base within the second access arrangement period for the purposes of its application.[230] However, as with the current methodology, at the conclusion of this access arrangement period, an adjustment to the capital base will be made to reflect actual inflation.

6.5.4 Submissions

The Commission has not received any comments from interested parties regarding this issue.

6.5.5 Commission's considerations

The Commission has assessed GasNet's inflation adjustments to the capital base over the initial access arrangement period. It has determined that that appropriate adjustments have been made and that actual inflation is reflected in the model and the resulting capital base values.

For this Draft Decision the Commission has used the expected inflation rate determined by the relevant bond rates, currently 2.5 per cent, to adjust the capital base through the second access arrangement period.

6.6 Pass-through events

As noted in the discussion on reference tariffs, GasNet has proposed a pass-through mechanism to avoid going through the Code's section 2 review process for specific cost changes within the second access arrangement period. The mechanism proposed by GasNet includes a pass through for tax increases, increased regulatory requirements and a rise in insurance premiums. The proposed mechanism would be asymmetric, and the Commission would only have 20 days to approve any pass through adjustment.

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[229] GasNet submission, 27 March 2002, p. 44.

[230] GasNet access arrangement information, 27 March 2002, p. 8.

The Commission considers that in principle a pass-through mechanism may be appropriate, but has proposed a number of amendments to the GasNet mechanism. These amendments are detailed in section 3 of this Draft Decision.

7. Volumes and revenue

7.1 Volumes

7.1.1 Code requirements

The Code (section 8.2(e)) requires that any forecasts used in setting the reference tariff should represent 'best estimates arrived at on a reasonable basis'.

7.1.2 Current access arrangement provisions

Volume forecasts for the first access arrangement period were based on a forecast developed by GASCOR in 1997 and adjusted to take into account factors such as new developments (for example, Carisbrook and the Interconnect).[231]

7.1.3 GasNet proposal

Both GasNet and VENCorp base their demand forecasts on those published in the VENCorp Annual planning review. However, GasNet proposes to adjust these estimates to account for a warming trend in Melbourne which it says arises from a combination of an enhanced Greenhouse effect and an urban heat island effect. GasNet states that the effect of this adjustment is to reduce the forecast annual load in 2007 by approximately 1.2 PJ.

Table 7.1: GasNet's forecast demand, 2003 to 2007

Demand and volume	2003	2004	2005	2006	2007
Peak demand (TJ/day)	1 132	1 174	1 209	1 235	1 257
Annual volume (PJ)[a]	216.2	225.3	232.7	237.2	241.3

Source: GasNet access arrangement information, 27 March 2002, p. 15.
Note: (a) Excludes storage refills of 3.6, 3.6, 4.3, 3.2 and 3.4 PJ over this period. GasNet submission, 27 March 2002, p. 105.

GasNet disaggregated its demand forecasts by zone (Table 7.2) on the basis of a range of assumptions including:

- Esso/BHP Billiton flows from Longford would fall from a maximum daily quantity (MDQ) of 830 TJ/day to 810 TJ/day;
- 35 TJ/day from the Baleen/Patricia/Kipper fields would be injected via a connection facility at Longford known as the VicHub (after being processed at Orbost and backhauled along the EGP);
- imports from Culcairn would fall from 28 TJ/day to 17 TJ/day;

[231] TPA additional supplementary information, 16 March 1998, p. 18.

- on-shore Otway Basin production would grow from 25 TJ/day to approximately 55 TJ/day before declining as production grows from Thylacine and Geographe to 60 TJ/day in 2006 and 90 TJ/day in 2007; and
- the Yolla project would not proceed.[232]

Table 7.2: Forecast zonal volumes, 2002 to 2007

	TJ/year					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
La Trobe	14 820	11 875	14 387	17 367	17 886	18 204
Tyers		2 390	3 213	3 337	3 762	4 388
Lurgi	1 475	1 521	1 564	1 611	1 659	1 709
Metro	166 110	170 437	174 858	178 091	180 640	182 895
Calder	8 435	9 509	9 907	10 181	10 396	10 536
Carisbrook	760					
South Hume	842	874	909	933	952	961
Echuca	6 735	6 986	7 262	7 451	7 611	7 691
North Hume	6 868	2 290	2 381	2 442	2 495	2 521
Wodonga		4 707	4 754	4 801	4 849	4 898
Murray Valley	829	1 094	1 364	1 608	1 849	2 127
Barnawartha	1 177					
Southwest Pipeline	520	570	573	578	681	784
Western	3 757	1 894	1 979	2 060	2 144	2 228
Koroit		580	606	631	656	682
Allansford		1 463	1 529	1 592	1 657	1 723
Total	212 328	216 190	225 287	232 683	237 239	241 346

Source: GasNet Erratum, 15 May 2002, p. 2.

7.1.4 Submissions

VENCorp notes that the demand forecasts provided by it and by GasNet are derived from the VENCorp Annual Planning Review (30 November 2001) forecasts which exclude WUGS withdrawals and NSW exports. VENCorp has provided the calendar year forecasts shown in Table 7.3 below to allow a direct comparison.

232 GasNet submission, 28 March 2002, schedule 6, p. 63.S

Table 7.3: Comparison of GasNet and VENCorp demand forecasts

Year	PJ[a]		
	GasNet	VENCorp/NIEIR	Difference
2002		211.4	
2003	216.2	216.6	0.4
2004	225.3	225.9	0.6
2005	232.7	233.5	0.8
2006	237.2	238.3	1.1
2007	241.3	242.6	1.3

Source: VENCorp submission, 13 May 2002, p. 20.
Note: (a) Forecasts exclude WUGS withdrawals and exports to NSW.

VENCorp submits that the difference in annual demand forecasts reflects different assumptions in respect of urban and global warming effects but is not material when other factors are taken into account:

> In summary, VENCorp has corrected forecast loads for the trend in temperature observations due to localised urban heating effects whereas GasNet's adjustments to the VENCorp forecasts assumes there is a heating effect across the PTS as a whole.
>
> The differences are not material when compared with the normal annual load variations due to weather cycles and load forecast uncertainty over 5 years.[233]

VENCorp also provided a comparison of peak day forecasts (see Table 7.4 below). It submits that the differences between the two sets of forecasts are essentially due to the difference in reference year. VENCorp forecasts that the peak winter day occurs in July or August which occurs in the financial year following the calendar year.

Table 7.4: Comparison of GasNet and VENCorp peak day demand forecasts

Peak day	TJ				
	2003	2004	2005	2006	2007
GasNet[a]	1 132	1 174	1 209	1 235	1 257
VENCorp[b]	1 104	1 133	1 170	1 208	1 236

Source: VENCorp Submission, 13 May 2002, p. 21.
Notes: (a) Calendar year.
(b) Financial year.

[233] VENCorp submission, 13 May 2002, p. 21.

Table 7.5: Forecast exports to NSW and WUGS, 2001-2002 to 2007-2008

Year[a]	TJ NSW exports	WUGS	Total
2002	500	3 277	3 777
2003	500	4 499	4 999
2004	500	2 922	3 422
2005	500	4 178	4 678
2006	500	5 088	5 588
2007	500	5 809	6 309
2008	500	6 216	6 716

Source: VENCorp Submission, 13 May 2002, p. 21.
Note: (a) Year ending 30 June.

Origin considers that there is still considerable uncertainty surrounding local and regional temperature change trends, including the impact of various influences such as urban pollution and wind patterns on local climate.[234] On this basis, Origin does not accept that it is appropriate to include a warming trend in the demand forecast for the forthcoming access arrangement period. Origin suggests that the GasNet and VENCorp access arrangements should incorporate consistent demand forecasts.[235] Further, Origin considers that GasNet would achieve 'asset over-recovery' if it included both a warming trend in the demand forecast and a higher asset beta based on exposure to volume risk.[236]

While acknowledging the difficulties attached to forecasting the impact of gas-fired power generation projects, Origin considers that 'the VENCorp and GasNet demand forecasting methodologies should be segmented into power plant demand and non-power demand' which it considers would assist the understanding of system utilisation and the likely impact on tariffs.[237]

BHP Billiton comments that GasNet's forecasts 'omit the impact of Yolla introducing gas at Lang Lang, … of Minerva gas going to South Australia, and of TXU shipping gas to South Australia from Ion[a].'[238] BHP Billiton also comments that GasNet has omitted zonal data on gas demand which it states is necessary in order to demonstrate the appropriateness of zonal tariffs. BHP Billiton considers that GasNet should provide zonal data including MDQ and five and ten day average maximum demand, and that the data should be compared to the actual capacity of the different zones.[239] Further, in the context of expected depletion rates for the Gippsland Basin gas reserves, BHP

234 Origin submission, 17 May 2002, p. 7.
235 ibid., p. 10.
236 ibid., p. 10.
237 ibid., pp. 7-8.
238 BHP Billiton submission, 17 May 2002, p. 9.
239 ibid., p. 10.

Billiton submits that 'demand forecasts by ABARE and NIEIR (relied upon by GasNet) are too high'.[240]

ENERGEX commented that it tended to support VENCorp's analysis regarding warming associated with greenhouse and urban heat island effects. ENERGEX questioned GasNet's reliance on metropolitan weather station data and commented that urban and rural weather station data were unable to support GasNet's claim. Further, ENERGEX considers that 'even if the reduction suggested by GasNet were true, the effect would be "in the noise" of the other statistical uncertainties underpinning the forecast.'[241] ENERGEX concluded:

> On balance therefore, we suggest that the GasNet model provides little value and that energy flows over the period of the access regime should be referenced to VENCorp's annual forecast. Consistent with our earlier proposal for joint application by VENCorp and GasNet, we believe that the underlying assumptions for the treatment of the assets should be the same for both of the two businesses. [242]

ENERGEX stated its preference that VENCorp's forecasts be used for both access arrangements. However, it noted that the proposals being put forward by the Victorian distribution businesses appeared to be more consistent with the GasNet approach and encouraged uniformity of approach.[243]

DEI recommended that consistent demand forecasts be required across the two access arrangements but did not specify a preference for either set of forecasts.[244] In addition, DEI stated that it considers that GasNet's forecast flows do not represent the most likely levels of production across the Victorian network. DEI considers that the forecasts significantly underestimate daily quantity flows for the VicHub facility while overestimating flows from Thylacine and Geographe (whose start-up date it considers may be outside the second access arrangement period). DEI also queried the forecast increase in La Trobe zone flows between 2001 and 2002 and considers an in-depth analysis of the demand forecasts is warranted.

AGL noted the difference between the two sets of forecasts and commented that 'the effect of a reduced load forecast coupled with a proposed increased capital base would tend to infer higher overall tariffs than would otherwise be the case.'[245]

BHP Billiton comments that the difference between the GasNet and VENCorp forecasts is less than 0.5 per cent and suggests GasNet can adjust tariffs through the K factor mechanism in response to disparities between forecast and achieved volumes. BHP Billiton suggests 'that a slight under estimation of forecast volume would be preferred to an over estimate' and that the Commission should ensure 'that any over recoveries resulting from poor gas volume forecasting are quickly returned to users'.[246]

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240 ibid., p. 6.

241 ENERGEX submission, 9 May 2002, p. 2.

242 ibid., pp. 2-3.

243 ibid., p. 8.

244 DEI submission, 13 May 2002, p. 2.

245 AGL submission, 9 May 2002, p. 3.

246 BHP Billiton submission, 21 June 2002, pp. 34-35.

7.1.5 Commission's considerations

Demand forecasts represent a critical element of any regulatory assessment under a building block approach like that applicable to GasNet's access arrangement. A service provider is subject to aggregate demand risk and will earn greater (less) than forecast revenue if actual demand is greater (less) than that forecast. A service provider therefore has a strong incentive to exceed the forecasts. It may seek to achieve this by encouraging demand growth. It may also attempt to base its tariffs on conservative demand forecasts.

The Commission has considered the views expressed by a number of parties that the aggregate demand forecasts for the second access arrangement period should be consistent across the two access arrangements and that the VENCorp forecasts should be preferred. It has also considered views relating to likely supply capacities from different sources over the next five years and the potential impact on flows across segments of the PTS.

The Commission notes the comparatively small differences between the aggregate gas demand projections underpinning the proposed GasNet and VENCorp tariffs. It considers that that these forecasts should be consistent across the two access arrangements. The Commission also notes that the ESC proposes to accept demand projections for the three Victorian gas distribution businesses' access arrangements which are consistent with GasNet's approach.[247]

The Commission considers that the VENCorp annual planning review forecasts have been determined through a transparent process involving public consultation and form a sound basis for the demand forecasts that will be used to derive the tariffs to apply for the second access arrangement period. It notes that the CSIRO report commissioned by GasNet supports a comparatively small adjustment to these estimates and that VENCorp considers that the differences between the estimates are not material when other factors are taken into account. GasNet considers that no credible critique has been provided of the CSIRO report.

On balance, the Commission proposes to accept GasNet's total demand forecasts for the PTS over the second access arrangement period. It will consider any further submissions by interested parties before making its final decision. An amendment has been proposed for the revised VENCorp access arrangement to ensure that consistent forecasts are used across the two access arrangements.

The accuracy of GasNet's zonal and customer class demand forecasts is also important as these feed directly into the tariff formulation. Customers in a zone or class (Tariff D or V) will be charged too much (little) if relevant future flows are under (over) estimated and GasNet will achieve more (less) than the expected revenue. However, the K factor adjustment can compensate for divergences in product mix. The Commission acknowledges the difficulty in accurately forecasting zonal and customer class flows, especially given the uncertainty attached to supply developments. Generally, it does not consider it appropriate to attempt to 'micro-manage' forecasts at

[247] ESC, *Draft Decision; review of gas access arrangements*, July 2002, p. 132.

this level and considers it reasonable for GasNet to enjoy some insulation from zonal demand risk.

The Commission has carefully assessed GasNet's zonal demand forecasts (provided in Table 7.2), and the comments of interested parties on likely flows during the second access arrangement period (including VENCorp's projections for exports to NSW and the WUGS facility (Table 7.5)). The Commission examined expected demand over assets such as the Southwest Pipeline which GasNet proposes to include in the capital base (see chapter 4). As a consequence of this assessment, changes are proposed to GasNet's injection forecasts. In light of information now available, the Commission considers that forecast flows from the Yolla field should be included from 2004.

Proposed amendment 23

GasNet must amend section 4 of its revised access arrangement information to include forecast flows from the Yolla field in its flow assumptions from 2004.

The Commission has also taken into consideration a range of other issues raised in submissions. For example it notes BHP Billiton's suggestion that GasNet's K factor mechanism can satisfactorily accommodate divergences from forecast demand. Similarly, it notes TXU's concerns that GasNet's proposed price control formula would allow GasNet the opportunity to earn more than its revenue requirement for reasons outside its control.[248] On this point it notes that the K factor mechanism provides compensation for product mix variations but not for differences in aggregate demand.

The Commission is cognisant of the difficulty in accurately forecasting zonal demand. While some parties have commented on individual aspects of GasNet's zonal forecasts, no overall alternatives have been proposed. The Commission does not consider that it has the expertise to propose alternative zonal forecasts. Accordingly, it proposes to accept GasNet's forecasts as being reasonable.

7.2 Forecast revenue

7.2.1 Code requirements

As noted previously, the Code sets out (section 8.4) three alternative methodologies for determining total revenue: Cost of Service, IRR and NPV.

7.2.2 Current access arrangement provisions

GasNet's predecessor used a Cost of Service methodology for the initial access arrangement period. Table 7.6 shows the benchmark revenue for the first access arrangement period which was calculated as the return on the value of the capital base and working capital plus depreciation of the capital base plus the operating and maintenance costs incurred in providing its services over the covered pipeline.

[248] TXU submission, 31 May 2002, p. 34.

Table 7.6: Benchmark revenue, 1998 to 2002

	$ million				
	1998	**1999**	**2000**	**2001**	**2002**
Return on assets	28.8	29.6	30.8	31.8	31.6
Depreciation	12.3	13.1	14.0	14.9	15.0
Return on working capital	0.7	0.6	0.6	0.7	0.7
Operations and maintenance	19.3	19.4	19.1	18.7	18.8
Total	61.1	62.7	64.5	66.1	66.0

Source: TPA access arrangement information, 30 November 1998, p. 17.

7.2.3 GasNet proposal

GasNet proposes to continue to use the Cost of Service methodology. Its proposed revenue and its constituents are shown in Table 7.7 below. A CPI-X price path giving the same NPV as the forecast revenue requirement is proposed in order to achieve a smooth tariff path. The revenue requirement and the benchmark revenue for the second access arrangement period are also shown.

Table 7.7: GasNet's proposed revenue, 2003 to 2007

	$ million				
	2003	**2004**	**2005**	**2006**	**2007**
Return on assets	45.73	45.62	45.72	46.02	46.17
Depreciation	19.28	20.04	21.16	21.91	22.16
Non-capital costs	42.91	23.69	23.43	25.25	25.66
Total revenue	107.92	89.35	90.31	93.18	93.99
Benchmark revenue	93.92	94.96	96.11	96.53	96.67

Source: GasNet submission, 27 March 2002, p. 104.

7.2.4 Submissions

No material issues were raised in submissions about the composition of GasNet's revenue requirement for the second access arrangement period.

7.2.5 Commission's considerations

The Commission considers that GasNet's proposal to maintain the Cost of Service approach and to utilise tariff smoothing is appropriate. However, as discussed in earlier chapters of this Draft Decision, a number of changes are required to GasNet's benchmark revenue assumptions. Table 7.8 below provides estimates of the (unsmoothed) revenue the Commission currently proposes over the second access arrangement period.

The actual benchmarks will be determined at the time of the Final Decision after smoothing to reduce volatility (consistent with a CPI-X price path). The Commission will incorporate relevant indicators of financial market conditions at that time.

Table 7.8: Estimates of GasNet's revenue, 2003 to 2007

	$ million				
	2003	**2004**	**2005**	**2006**	**2007**
Return on capital	33.1	33.1	33.5	33.9	34.2
Depreciation	17.3	18.0	19.0	19.4	19.2
Operations and maintenance	30.0	20.9	20.7	22.4	22.8
Total revenue	80.3	72.0	73.1	75.7	76.2

Source: ACCC analysis.

8. Reference tariffs

8.1 Cost allocation and tariff structure

8.1.1 Code requirements

Section 8.38 of the Code requires that reference tariffs should recover costs directly attributable to the reference service and a fair and reasonable share of joint costs. Section 8.42 requires that recovery of a particular user's contribution to revenue also follows these principles.

An exception to these principles is the case of prudent discounts. If a user or prospective user would not be a user at the reference tariff then the Code (section 8.43) allows for a lower tariff to be charged (that is, a prudent discount to be given) to that user with the shortfall in revenue met by raising tariffs to other users. This is conditional on the prudent discount not causing tariffs to other users to be higher than they would have been if the potential user in question was not a user.

8.1.2 Current access arrangement provisions

Under the provisions of GasNet's access arrangements, all costs of a direct capital nature (return on and return of capital) are allocated to each of the 24 asset groups on the basis of the ORC of the assets in each group. Locational operating and maintenance (O&M) costs are allocated to asset groups on the basis of pipeline length. The costs for each asset group are allocated to off-take points within that group based on usage and the length of pipe used. Costs of an indirect nature (that is, non-locational O&M, return on and depreciation of corporate headquarters buildings) are allocated on a postage stamp basis (a set amount per gigajoule transported).

For pricing, the off-take points are amalgamated into eight pricing zones. Costs are recovered through three tariffs: an injection charge on the five peak injection days; a peak withdrawal charge on the five peak withdrawal days; and an anytime withdrawal charge on the total volumes throughout the year. Some tariffs are reduced for users upstream of the notional hub at Pakenham to reflect the fact that they do not use all of the injection pipeline.

The direct costs associated with the injection pipeline are recovered by the injection tariff. The direct costs associated with the withdrawal zones are recovered by the peak withdrawal tariff. The costs recovered by these two peak charges are 65 per cent of total costs. The locational O&M and the indirect costs are recovered by the anytime withdrawal tariff.

8.1.3 GasNet proposal

GasNet proposes to abolish the current peak withdrawal tariff and simply charge an injection tariff based on peak usage and a withdrawal tariff based on annual usage. GasNet states that while users have concerns over the operation of the peak withdrawal tariff 'no concerns have arisen with respect to the use of peak day injection tariffs, or with the extent and coverage of the tariff zones.'[249] GasNet proposes that the new structure would be re-assessed at the next scheduled access arrangement revision.[250] GasNet also proposes to add to the current tariff classes (Tariff D and Tariff V) a new class of Refill tariff for storage which would be charged at marginal cost (which is the cost of compressor fuel at the appropriate compressor station).[251]

Under GasNet's proposal, direct capital costs (return on and return of capital) associated with pipeline, regulator and compressor assets are apportioned among the 27 pipeline segments according to the ORC of each asset. Direct operating costs are allocated to these segments according to pipeline length (in the first access arrangement period they were allocated only to withdrawal pipes). There are two major exceptions to this method. First, the costs (capital costs and incremental operating costs) associated with the Southwest Pipeline are allocated directly to that asset. Second, the majority of the Interconnect costs are allocated on a postage stamp basis (see below) while the remaining 'residual' costs of the Interconnect (eight per cent of the total) are allocated directly to that asset.

The remaining costs are the indirect costs and consist of the capital costs of non-system assets, general and administrative O&M, return on working capital, benefit sharing allowance, recovery of unrecovered K factor balance, asymmetric risks and capital raising costs, as well as the majority of the Interconnect costs rolled in under the system wide benefits test. These costs are allocated on a 'postage stamp' basis: that is, each gigajoule transported is allocated the same cost, irrespective of where it enters and leaves the system.

Costs associated with injection pipes will be recovered by the peak injection charge. A separate injection charge applies to each injection point and is based on the 10 peak days usage at the relevant injection point. Injection costs account for 27 per cent of total costs.

The costs for each pipeline segment, other than for injection pipeline assets, are then allocated to each off-take point within the pipeline segment (and to gas flowing through the segment) on the basis of usage and distances flowed.[252] GasNet proposes, for the complete PTS, that usage be determined by forecast peak usage (which is now defined as 1 in 2 winter peak flows rather than the 1 in 20 winter peak flows used in the first access arrangement period) for the allocation of 60 per cent of the costs and by anytime usage for the other 40 per cent of the costs. It proposes that the costs associated with injection pipelines be allocated 100 per cent by peak usage (as the tariff will be a peak tariff) and that the remaining costs, associated with the withdrawal zones, be allocated 45 per cent by peak usage and 55 per cent by annual usage to each off-take. Thus a total of 60 per cent of costs will be allocated by peak volumes.[253]

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249 GasNet submission, 27 March 2002, schedule 5, p. 36.

250 ibid., p. 47.

251 ibid., p. 51.

252 To work this out, one needs to determine the direction of forecast flows. The injection point for each off-take is determined by allocating forecast injection volumes to the off-takes nearest the injection point until all forecast volumes are allocated.

253 27% + 45% of (100%-27%).

The total costs applicable to users at an off-take will be the costs calculated above plus the appropriate proportion of the costs calculated for gas passing through all other segments on the physical path from the injection point to the off-take point. Finally, the costs associated with all the off-takes in each price zone are added together and divided by the annual usage to derive the withdrawal anytime tariff. GasNet proposes to divide users into 15 price zones, an increase over the current 12.[254] Throughout this process the costs applicable to Tariff V and Tariff D customers are isolated so that separate tariffs are calculated.

The above cost allocation and tariff structure mean that while 60 per cent (compared with 65 per cent in the first access arrangement period) of costs are <u>allocated</u> to users on the basis of peak volumes, only 27 per cent of costs (compared with 65 per cent in the current access arrangement period) are <u>recovered</u> through peak charges.

GasNet has proposed several refinements to the general approach described above. Consistent with the access arrangement as it currently stands, GasNet proposes lower injection tariffs for zones close to Longford (which do not use the full injection pipeline). GasNet is proposing a similar approach for matched withdrawals close to other injection points.

GasNet also proposes that withdrawal tariffs in the northern zones (North Hume, Wodonga and Murray Valley) be reduced for gas injected through the Interconnect to reflect the smaller portion of the system used. Further, several points on the system have been identified where GasNet considers it would be prudent to offer a discount (to avoid creating a bypass opportunity).

8.1.4 Submissions

Some submissions strongly support the removal of the peak withdrawal tariff and call for the removal of the peak injection charge. The main argument for this position is that users are unresponsive to price signals and the result would be administratively easier.[255] Other submissions state that the peak withdrawal charge should be retained to give appropriate price signals to users.[256] BHP Billiton states that the GasNet system is designed to accommodate peak winter demand and that therefore a high proportion of revenue should come from these maximum demand requirements. It is argued that allocating costs on annual flows does not send the appropriate signals to users to reduce demand at times of constraint and is not cost reflective.[257] However EnergyAdvice, in

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[254] As noted above, the access arrangement currently divides users into eight zones. A ninth zone was defined (in the west Gippsland area) but it did not contain any users. The Murray Valley pipeline was not considered a zone as users on it had to pay the tariff for the North Hume zone as well as an incremental tariff for the Murray Valley pipeline. The Murray Valley pipeline is now considered a separate zone. Since 1998, the Interconnect and the Southwest Pipeline have both been added to the system and each of these is considered to constitute a separate zone. Consequently, while eight zones were noted in the first access arrangement period, the 15 zones now proposed are a result of adding three new zones to the 12 current at the end of 2002.

[255] ENERGEX submission, 9 May 2002, p. 4; AGL submission, 9 May 2002, p. 1; TXU submission, 31 May 2002, pp. 17, 19 and 22.

[256] Amcor and PaperlinX submission, 24 June 2002, pp. 16-17; Origin submission, 17 May 2002, p. 9; EnergyAdvice submission, 30 May 2002, pp. 3-4.

[257] BHP Billiton submission, 21 June 2002, p. 17.

its argument for peak price signals, also acknowledges that these signals have limited ability to alter behaviour. It states '[t]he incentive for end users to try to avoid system peak withdrawal days has significantly diminished with the tariff redesign, however we are unaware of end users actively seeking to avoid these costs under the current tariffs.'[258]

Some submissions opposed the allocation of costs on a postage stamp basis. BHP Billiton, Amcor and PaperlinX regard a more appropriate basis of allocation to be maximum MDQ or number of transactions (for General and Administrative), diameter-length of pipeline (for working capital) and a K factor redistribution towards those assets not returning the anticipated share of expected revenue.[259]

Several submissions commented on the allocation of the under-recovered K factor amount. BHP Billiton maintains that future benefits and K factor under-recoveries need to be allocated to where they are generated but also that the postage stamped costs need to be allocated to discrete elements (such as the Southwest Pipeline and WTS).[260] However, it also seeks no cross-subsidisation between WTS, Southwest Pipeline and PTS including separation of the first two from the K factor calculations.[261] EUAA makes similar points.[262]

DEI expressed concern with the definition of 'shipper' which could exclude some activity from being treated as matched withdrawals when it is more appropriate that they be so.[263]

BHP Billiton contends that the tariff structure must reflect the expectation that the Southwest Pipeline will be an under-utilised resource in the second access arrangement period.[264]

AGL points to what it considers to be an inconsistency in the Culcairn withdrawal charge[265]

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258 EnergyAdvice submission, 30 May 2002, p. 5.

259 BHP Billiton submission, 21 June 2002, pp. 13, 19 and 36; Amcor and PaperlinX submission, 24 June 2002, pp. 18-19.

260 BHP Billiton submission, 21 June 2002, p. 11.

261 ibid., p. 10.

262 EUAA submission, 11 July 2002, pp. 6 and 10.

263 DEI submission, 13 May 2002, p. 3.

264 BHP Billiton submission, 21 June 2002, p. 12.

265 AGL submission, 9 May 2002, p. 2. As the Commission understands GasNet's proposal, no exports to NSW are forecast. Consequently, the costs allocated to the Interconnect are recovered by the injection tariff for the Interconnect which is based on the volumes forecast to flow south along it. The withdrawal tariffs for the northern zones are calculated based on these zones being supplied from Longford, but with no export volumes being included in the calculation. In the event that some volumes are exported, GasNet has developed a tariff by calculating the North Hume withdrawal tariff as before but including 3PJ of export volumes as well. This produces a lower withdrawal tariff for exports (reflecting the fact that if they occur then the tariff should be lower to reflect the greater volumes flowing). There would be no Interconnect injection tariff charged on these exports. The Commission does not understand what AGL considers inconsistent in this approach.

EnergyAdvice suggests that if users responded to the new price signals by undervaluing demand management then the supply side could become prematurely stressed requiring additional investment and thus higher tariffs.[266]

TXU considers that the proposed tariffs are very complex, are likely to distort investment decisions and are not efficient.[267] TXU calls for a reduction in the number of zones to reduce complexity and reduce rural and urban price differentials.[268] TXU is very concerned that all charges (specifically the injection charge) cannot be allocated to specific customers.[269] TXU appears to advocate charges being standardised between users.

Amcor and PaperlinX oppose the proposed allocation of costs on a postage stamp basis on the grounds that it would disadvantage users with a flat load.[270]

TXU notes that the VENCorp planning review says there is unlikely to be major congestion in the next five years, and questions the peak pricing approach.[271]

VENCorp and ENERGEX submit that GasNet but not VENCorp should be responsible for offering prudent discounts.[272] However, ENERGEX is not convinced that customers generally should finance the prudent discounts that GasNet is proposing.[273] No reason is given for this view.

8.1.5 Commission's considerations

Much of the proposed tariff structure and cost allocation is essentially unchanged from that approved by the Commission in 1998. At that time the Commission was satisfied that the cost allocation methodology was appropriate and that tariffs would recover a fair and reasonable share of costs from each user.[274] The Commission's assessment is that this general structure continues to be appropriate for the reasons indicated in the 1998 Final Decision. It notes that GasNet undertook a public consultation process in 2001 which considered users tariff preferences. It will concentrate its assessment of the current proposal on those elements which differ from the arrangements currently in place.

The key proposed changes which have prompted concern from the Commission and/or been raised in submissions are:

- the increased complexity of the tariffs (with consequent concerns by some parties that GasNet may be able to over-recover costs in some instances);

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266 EnergyAdvice submission, 30 May 2002, p. 5.

267 TXU submission, 31 May 2002, pp. 16-17.

268 ibid., p. 19.

269 ibid., p. 22.

270 Amcor and PaperlinX submission, 24 June 2002, p. 17.

271 TXU submission, 31 May 2002, p. 23.

272 VENCorp submission, 13 May 2002, p. 7; ENERGEX submission, 9 May 2002, p. 2.

273 ENERGEX submission, 9 May 2002, p. 2.

274 ACCC, 1998 Final Decision, p. 91.

- the removal of the peak withdrawal tariff and the change in relativities between peak and anytime tariffs;
- the allocation of direct O&M to injection pipelines;
- the allocation of the unrecovered K factor adjustment, GasNet's share of the efficiency benefits from the first period and the capital raising costs by the postage stamp method;
- the introduction of a cross-system withdrawal tariff; and
- an increased number of matched withdrawal tariffs and the introduction of some prudent discounts.

In the 1998 Final Decision, the Commission accepted the proposed proportion of revenue to be recovered by the peak and anytime charges (67:33 per cent), noting that there was no theoretically correct proportion (as recovery of total costs necessitated charging at above marginal cost). The Commission foreshadowed that it would revisit the issue at the end of the first access arrangement period.[275] Also in that Final Decision, the Commission noted the dependence of the derived tariffs on the assumptions in the modelling on the assumed source of gas. It indicated that the review in 2002 would be a more appropriate time in which to take sourcing into account for the annual tariff calculation.[276] Finally, the Commission noted that, when assessing the next scheduled revisions to the access arrangement, it would give more consideration to the question of forecasting northerly and southerly flows on the Interconnect.[277]

Overall complexity

Cost allocation and tariff structure design for pipelines will generally be expected to involve a number of trade-offs. Considerable complexity may be required to achieve a high level of cost-reflectivity but this may result in needlessly high costs. This is recognised in the Code (sections 8.38 and 8.42) which requires cost-reflectivity to be maximised subject to the constraint of it being technically and commercially reasonable.

In responding to comments by parties favouring greater equalisation of charges and simpler tariffs, GasNet noted that it is constrained by the requirements in the Code for efficient cost allocation.[278]

In considering these tensions, the Commission is aware that individual users and end-users may be comparatively advantaged or disadvantaged by a particular approach. For example, merging of tariff zones would have the effect of averaging charges that would otherwise differ. Similarly, different tariff designs can impact significantly on the charges which would be paid by customers with different usage patterns.

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[275] ibid., p. 85. The peak: anytime ratio of 67:33 was for 1998. It was noted that it would increase to 70:30 in 2002. As noted in section 8.1.3, GasNet refers to the split in the first access arrangement period as 65:35.

[276] ibid., p. 88.

[277] ibid., p. 90.

[278] GasNet response to submissions, 12 June 2002, p. 10.

GasNet proposes to remove the peak withdrawal tariff but to add extra matched withdrawal tariffs, prudent discounts, a transmission refill tariff, a cross-system withdrawal tariff, three extra pricing zones and more injection points. Some parties regard this complexity as unnecessary. Further, some consider that certain features of the proposed tariff structure would allow GasNet to over-recover the benchmark revenue. The Commission has considered an example provided by TXU to demonstrate potential over-recovery.[279] However, the Commission's assessment is that GasNet would not over-recover in this case as the K factor adjustment at the end of the year would lower the tariffs applicable in the following year.

While the K factor mechanism has been in effect since 1999, comments in several submissions suggest that not all interested parties fully understand its operation. Importantly, GasNet's access arrangement contains (and it is proposed that it will continue to contain) an average revenue (not total revenue) control. Any differences between the total volume actually demanded, and that forecast, will be borne by GasNet. Any changes in the product mix (for example, the relativities between zones or customer classes) are borne by users. Any under-recovery or over-recovery of average revenue, because of changes in product mix, is corrected by the K factor adjustment to future tariffs. The average revenue control therefore does not allow for the potential over-recovery that concerns some interested parties. See section 6.2.2 of this Draft Decision for a more detailed explanation.

The Commission has considered concerns about the complexity of the proposed tariffs. It recognises that there are more elements to the tariff structure and that this requires more effort in their assessment. However, it is not persuaded that this complexity would hinder the operation of the market to the extent that the structure should be rejected. The appropriateness of each element is assessed below.

Peak and non-peak relativities

As noted above (section 8.1.3), while GasNet proposes that 60 per cent (65 per cent in the first access arrangement period) of costs be <u>allocated</u> to users on the basis of peak volumes, it proposes only 27 per cent of costs (65 per cent in the first access arrangement period) be <u>recovered</u> through peak charges.[280] This is a major difference in the way in which revenues are collected from users. The effect on individual customers is that the higher a customer's load factor, the greater will be the increase in average tariffs compared to customers with low load factors. That is, customers with high load factors will now contribute to the recovery of costs more than they used to, compared to customers with low load factors and thus the differential between the tariffs paid by high load and low load users is reduced. A customer's load factor will be reflected in its injection charge and whether it is a Tariff V or a Tariff D customer (the load factors

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[279] TXU submission, 31 May 2002, pp. 24-25. See also AGL submission, 9 May 2002, p. 2.

[280] As a result of several amendments the Commission proposes throughout this Draft Decision, the proportion of costs allocated to the peak injection tariff is likely to be marginally lower than 27 per cent.

of these two user groups determine, in part, the differential between the two withdrawal charges).[281]

As some submissions have noted, this may diminish the incentive customers have to manage their load. The peak charge is a price signal about the cost of congestion and that would be removed in part (it would still exist in the injection tariff).

GasNet argues that most laterals are low volume and unconstrained and that with more gas being supplied at injection points other than Longford there are no constraints within the hub.[282] On this basis it would be inappropriate for these parts of the system to be priced based on peak flows. However, if there is little likelihood of these pipes being constrained, it could be argued that no peak signal at all is appropriate (and consequently that there should be one withdrawal tariff for Tariff V and Tariff D customers). GasNet recognises this argument but proposes that some pricing according to peak usage remains so that peaky and non-peaky customers do not experience a significant change in relative tariffs.[283]

There are, of course, many alternatives available to GasNet for the pricing of its services. Broadly speaking, apart from that proposed by GasNet, two are suggested by interested parties. One is that the peak withdrawal charge be maintained and the other is that the peak injection tariff be removed. The first option is essentially that the current tariff structure be maintained. The alternative is that all peak pricing signals be removed, which is essentially a view that there be one common anytime tariff.

Evaluation of these two options, as well as GasNet's proposal, mainly turns on the primary question of whether there should be peak pricing signals. This turns on two associated questions: is there (or is there likely to be) constraint on the system; and will users respond to the possible price signals available?

On the question of system constraints, GasNet says that there are no constraints on the system at the moment and, if there are likely to be any constraints, they are likely to occur on the injection pipelines and not the rest of the system.[284] However, the Commission notes the following:

- GasNet has forecast capital expenditure for looping of the Brooklyn-Corio pipeline on the grounds that the Southwest Pipeline is forecast to be constrained from 2007.[285] However, the forecast constraint in shipping gas from Port Campbell is not because the Southwest Pipeline lacks the capacity, but because the pipeline connecting the Southwest Pipeline to Melbourne lacks the capacity. It is not the Southwest Pipeline itself that would be approaching constraint under this scenario.

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281 The other factor that determines the difference between the Tariff V and Tariff D withdrawal tariffs for a particular zone will be the location of users (the average distance from the start of the zone).

282 As well as the access arrangement information and accompanying submission, GasNet repeated this claim in its response to submissions, 12 June 2002, pp.10-11.

283 GasNet submission, 27 March 2002, schedule 5, p. 42.

284 GasNet response to submissions, 12 June 2002, pp. 10-11.

285 ibid., p. 10.

- Since GasNet submitted its proposed revised access arrangement, Origin has committed to develop the Yolla field and plans to be delivering 20 PJ/year of gas into the system near Pakenham by 2004.[286] Depending on the destination for this gas, and the reaction of other gas suppliers, this may delay any congestion on the Brooklyn-Corio pipeline that would otherwise occur.
- The Commission understands that if the northern zones receive all their gas from the south, and none through the Interconnect, then the northern line (Wollert to Barnawartha, which links the Interconnect to Melbourne) would soon become constrained. Information in the VENCorp planning review indicates that there could be a 50 per cent chance of the pipe being constrained in 2006.[287] Currently 5PJ/year is imported from NSW via the Interconnect but the Commission understands that this contract expires early in the second access arrangement period.
- Similarly, the western system could have little capacity available at the end of the second access arrangement period.[288] GasNet acknowledges that the western system is near capacity but says that the commencement of the proposed Port Campbell to Adelaide pipeline from 2004 will ensure that constraints are not likely to occur.[289] However this may not be the case if GasNet's proposed prudent discounts successfully retain all its users.
- The Longford pipeline has a capacity of 970 TJ/day. However, GasNet is forecasting 830-845 TJ/day with demand above that to be supplied from other pipelines.[290] If this is the most likely scenario then there will not be constraint on this pipe and there is no reason for a peak signal.

The above indicates that the pipelines more likely to face constraint are not those classified as injection pipelines. Instead, they are pipeline whose costs are recovered through the withdrawal charge. The discussion above gives reasons for believing that the pipelines could be constrained in the next access arrangement period and also reasons why they may not: it appears a reasonable case could be made for either scenario.

The Commission is not convinced that congestion is likely in the next access arrangement period. However, it considers that it is possible that congestion could occur in the access arrangement period starting 2008 and is conscious of the need for users to face stable tariff structures. It would be unnecessarily disruptive for all peak signals to be removed for the second period only to be reintroduced in the third period. The Commission also notes that peak signals are appropriate before congestion occurs: they are not only a tool for the allocation of capacity costs to those who constrain the system, they are also a tool to discourage users from producing the capacity constraint.

[286] For further information see http://www.bassgas.oerl.com.au/

[287] See VENCorp Energy Networks Corporation, Annual Planning Review 2002-2003, November 2001, pp. 20 and 33-34 (which is Annexure 11 to GasNet submission, 27 March 2002).

[288] ibid., pp. 21-22 and 38.

[289] GasNet response to submissions, 17 July 2002, p. 14.

[290] GasNet submission, 27 March 2002, schedule 6, p. 63.

Finally, the Commission considers that the evidence suggests that congestion is likely to occur on withdrawal pipes first, rather than injection pipes as GasNet claims.

On the question of users' and end-users' response to peak signals, while some submissions call for peak pricing signals to provide appropriate signals, they do not provide evidence that the signals have any effect. Other submissions indicate that users have not responded to the peak signals in the current tariff structure.

GasNet has indicated that transmission charges account for only about 5 to 10 per cent of the final cost of delivered gas for the average user.[291] For such a user, the motivation to alter behaviour in order to possibly avoid 65 per cent of transmission charges (or, as proposed, only 27 per cent of charges) is quite small. There are some users for whom transmission is a bigger component of the overall price (for example, users in high tariff zones who do not use any distribution system). However these users are only a small proportion of all users, and even for most of these users avoidable transmission costs under the current access arrangement are less than 16 per cent of delivered cost.[292] Thus, while for a few users the existence of peak tariffs would afford the opportunity to significantly reduce the delivered cost of gas, it is hard to see how the current provision of peak signals could produce a significant difference in usage. This analysis accords with the observations on users' behaviour noted in the submissions mentioned above.

Consequently, the Commission is not convinced that a significant proportion of users respond to the current price signals. It is therefore less likely that the proposed (weaker) peak price signals will affect user behaviour.

While cost-reflective pricing and efficient pricing signals are of concern to the Commission, there are also other factors to be taken into consideration. Many users regard the current tariffs as too complex, confusing and cumbersome. However, the most concern is in relation to the annual 'wash up'. This is an account settling process necessary because users pay peak charges each month to smooth out their payments. This necessitates charges based on forecasts until such time as actual usage on the peak days is known and the appropriate adjustment can be made. Users consider this process not only to be complex but also to multiply administrative difficulties in allocating costs to individual customers (especially contestable customers). It appears to be for this reason that many interested parties advocate the abolition of all peak charges. GasNet, on the other hand, while acknowledging these issues, considers them to be largely connected with the peak withdrawal charge, claiming that it has received little complaint about the peak injection charge.

In conclusion, the Commission does not find the evidence available to it on congestion and price signals to be particularly convincing for any of the three alternative tariff structures mentioned above. Therefore, it proposes at this stage not to oppose GasNet's proposal to remove the peak withdrawal tariff but keep the peak injection tariff (which

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291 ibid., schedule 5, p. 36.

292 The highest case scenario (except for the few users in the Murray Valley) is a Tariff D customer in North Hume where (for 2002) the anytime charge is 27 cents and the peak is 55 cents, assuming a load factor of 70 per cent. If it is assumed that gas costs \$2.70 then the avoidable cost as a percentage of total cost is 15.7 per cent (55/(27+55+270)). Note that this analysis does not consider the VENCorp charges which would make the percentage of costs that are avoidable slightly less.

will recover 27 per cent of revenues). It will consider further submissions on this matter.

Cost allocation

As noted above, GasNet has not proposed many changes to its method of allocating costs. Capital costs for pipelines are allocated to asset zones on the basis of the zone's ORC in proportion to the ORC of the system. Capital costs for compressors are allocated to compressors on the basis of ORC. The capital costs of regulators, the odourant plant and city gates are allocated directly to the asset zone with those assets. Direct operating costs are allocated to asset zones on pipeline length while indirect costs are allocated on a postage stamp basis. The main variation from the current provisions of the access arrangement is that GasNet proposes to allocate direct operating costs to both withdrawal and injection pipelines. At present the allocation is only to withdrawal pipelines. The Commission accepts this proposed change as being an appropriate allocation of these costs.

As noted above, some interested parties suggested that general and administrative costs would be better allocated on the basis of maximum MDQ or the number of transactions. The Commission understands that various parameters can be considered appropriate for each type of non capital cost. However, as noted in the Commission's 1998 Final Decision, it considers that for the sake of simplicity, allocation of locational operating costs on the basis of pipeline length alone is a reasonable approach to cost allocation.[293] Similarly, while various parameters can be considered appropriate for the allocation of common costs, for the sake of simplicity, allocation on volume alone (the postage stamp approach) is considered reasonable. The only exceptions to this are costs which were not included in the common costs for the first access arrangement period and which are dealt with below.

In the current cost allocation, locational and common operating costs are identified separately for the Western zone and charged to that system.[294] GasNet has not indicated that it proposes to continue this separation and the Western zone is allocated operating costs and other common costs (except for the rolled-in Interconnect costs) in the same way as any other zone. The Commission considers this approach to be consistent with the integration of the WTS into the PTS.

Postage stamp allocation

The rationale for allocating costs on a postage stamp basis (a fixed amount per gigajoule transported, irrespective of the distance transported) is that the costs so allocated are costs incurred by users equally, irrespective of their physical location or other attributes (such as load factor). This approach was accepted by the Commission in 1998 for indirect costs (such as corporate office functions) and the Commission does not see any reason to change this approach now.

However, there are several new costs (or categories of costs) which GasNet is proposing to be included in the tariff calculations and which it proposes to allocate on

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[293] ACCC, 1998 Final Decision, p. 84.

[294] ibid., p. 80.

the postage stamp basis. The appropriateness of this approach needs to be assessed for each of these new cost categories.

As indicated in section 10.1.5, the Commission does not consider that it is appropriate for GasNet to receive any additional revenue in the second access arrangement period on the basis of claimed efficiencies in operations and maintenance costs in the first period. Similarly, a return on working capital is not considered to be appropriate (see section 6.2.5). Consequently, there is no need to consider the proposed cost allocation of these costs.

The Commission is of the opinion that the allowance for asymmetric risks is appropriately allocated on a postage stamp basis as the benefits to users are not discernibly related to users' location.

However this is not true of the amount for unrecovered K factor adjustment and capital raising costs.

The K factor adjustment has remained partly unrecovered because of the inappropriate limitation on individual tariff increases in the first access arrangement period. If this limitation had not existed – if the individual tariff control was the same as that proposed for the second access arrangement period – then the K factor adjustment would likely have been recovered by increasing each tariff by the same percentage amount (see section 6.2.2).[295] Consistent with this, the Commission considers that the K factor recovery should be allocated to all tariffs (except the tariff for the Southwest Pipeline) as a uniform percentage increase. The K factor adjustment should not be allocated to the Southwest Pipeline as it is not currently in the K factor calculations and therefore has not contributed to the unrecovered revenues.[296]

Proposed amendment 24

GasNet must amend section 5.3 of its revised access arrangement information to allocate the K factor under-recovery of $10 835 874 million (in 2003 dollars) to all tariffs (other than those for the Southwest Pipeline) as a uniform percentage increase.

Capital raising costs, by their very nature, are costs linked to the level of capital required. The Commission therefore considers it appropriate to allocate these costs on the same basis as other capital costs (which are apportioned over all system assets on the basis of their ORC).

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[295] This is only approximately correct: the control would allow some tariffs to be set at a lower rate but only as long as those tariffs increasing at a faster rate (to maintain the average increase) did not increase by more than one percentage point above the increase in the average tariff.

[296] As BHP Billiton appropriately noted, the K factor under-recovery should be allocated to those assets which generated it: BHP Billiton submission, 21 June 2002, p. 11. This approach of the Commission is contra to submissions which called for the Southwest Pipeline to be allocated some of the K factor under-recovery. See Amcor and PaperlinX submission, 24 June 2002, p. 10; BHP Billiton submission, 21 June 2002, p. 13; EUAA submission, 11 July 2002, p. 10.

Proposed amendment 25

GasNet must amend section 5.3 of its revised access arrangement information to allocate capital raising costs on the same basis as it allocates depreciation and return on capital.

Allocation by usage

Some submissions have suggested that removal of the peak tariff is inappropriate as it could produce tariffs which are not cost reflective. However, cost-reflective tariffs result from the distribution of costs to users based on usage. The resulting tariffs will be cost-reflective whether the usage is defined as peak usage or annual usage. The choice of usage definition depends on what the tariff design is intended to achieve. As noted above, if there is congestion, a peak tariff may be appropriate (if it provides a price signal to which users are able to respond). Alternatively, if there is no congestion an annual tariff may be more appropriate.

Direct capital costs were allocated to users on the basis of peak usage in the initial access arrangement period. These costs are associated with the capacity of the system. These direct capital costs are 65 per cent of all costs. GasNet is proposing for the second access arrangement period to allocate 60 per cent of total costs to users on a peak usage basis. This reduction does not reflect a fall in direct capital costs. Rather, GasNet considers that signals relating to system capacity are at present of limited value as the system is not approaching constraint. GasNet considers that a larger reduction would result in an unnecessarily large tariff shock.[297]

As noted above, with 60 per cent of total costs allocated to users on a peak usage basis, if all injection costs (27 per cent of all costs) are allocated on this basis, 45 per cent (55 per cent in the current access arrangement period) of the withdrawal costs will also be allocated on the basis of peak usage.

Allocation of costs to each off-take point within an asset zone (on the basis described in the paragraph above) occurs after costs are allocated to asset zones (see *Cost allocation* earlier in this section). It is this allocation procedure that helps create the difference between the tariffs for Tariff V and Tariff D customers within a zone. It will increase the tariff for Tariff V users (and lower the tariff for Tariff D users) because Tariff V users tend to have peakier demand.[298]

GasNet's proposal to allocate 45 per cent of withdrawal costs to peak usage (down from 55 per cent) will reduce these relativities. Whether this is appropriate depends on the same questions discussed above on the issue of whether there should be peak charges: are there (potential) system constraints which should be signalled, and are users likely to respond to those signals? Alternative approaches would include

297 GasNet submission, 27 March 2002, schedule 5, p. 42.

298 The other contributor to the Tariff V:Tariff D differential is the location of customers within the zone. For example, if the majority of Tariff V customers are located close to the supply source of the zone and the majority of Tariff D customers are located near the end of the zone (and thus use more system assets) then in this case Tariff D tariffs will be higher and Tariff V tariffs lower.

maintaining the allocation at 55 per cent and for it to be completely based on annual usage.

The evidence concerning constraints is discussed above. However, the peak withdrawal signals produced by GasNet's proposed tariffs will be much more muted than the question on whether there is a peak tariff or not. It is proposed that there would be two tariffs in each zone: for Tariff V and Tariff D (as there are now). However, customers are not able to respond to these signals resulting from tariff differentials between these two classes (although some Tariff V customers could potentially increase their usage sufficiently to become Tariff D customers). Thus, it is questionable whether the differential between Tariff V and Tariff D serves any useful purpose with respect to price signals.

Of course, effective price signalling is not the only reason to maintain these relativities: each user's tariff is meant to reflect the costs associated with that user. However, the question then becomes: if there is no constraint, does the cost of a gigajoule shipped by users differ according to a user's load factor, or more correctly, according to whether they are Tariff V or Tariff D? Again, the Commission considers the evidence inconclusive. Consequently it proposes not to oppose GasNet's proposal to allocate 45 per cent of withdrawal costs on the basis of peak usage, but calls for interested parties to present further evidence on the issue.

Matched rebates

Matched rebates on injection tariffs are proposed for users who do not use all of the injection pipeline. These rebates currently apply to users in the La Trobe and Lurgi zones whose gas is matched to injections at Longford. It is proposed that Tyers and West Gippsland will also be rebated for such injections. Similarly, matched injections are proposed for the Interconnect zone users who inject at Culcairn, and South West and Western zone users injecting at Port Campbell. The Commission considers it appropriate that the injection tariffs reflect the portion of the injection assets used by customers and does not object to the proposed matched rebates.

GasNet proposes to offer matched rebates on withdrawals from the North Hume, Murray Valley, Interconnect and Wodonga zones for gas injected at Culcairn in order to reflect the shorter transportation distance, that is, the lower use of the PTS, compared to gas sourced from Longford. Flows through the North Hume zone are relatively low resulting in a substantial increase in tariffs (for Longford sourced gas) in that zone and those zones further north: at least 50 per cent higher than current tariffs. GasNet considers that such tariffs are not genuinely cost-reflective because they will substantially exceed the long run marginal cost of supply to these zones. However, GasNet also states that tariffs that fall between marginal cost and stand-alone costs will be efficient.[299] The Commission notes that the Code requires that tariffs should recover any costs directly attributable to a service and a fair and reasonable share of joint costs. Any tariff between marginal cost and stand-alone costs can be considered to be free of cross subsidy: the question is whether the costs reflected by a particular tariff are appropriate or whether a different tariff would reflect a more appropriate allocation of costs.

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[299] GasNet submission, 27 March 2002, schedule 5, p. 44.

GasNet states that to the extent that they are above marginal cost, tariffs will send an inappropriate price signal and discourage gas consumption. However, the nature of the PTS assets is that most tariffs will be above marginal cost. If all tariffs were set at marginal cost, GasNet would not recover its required revenue. More appropriately, GasNet argues that adherence to its cost allocation model in this case will produce very high tariffs that will discourage gas flows to a greater extent than a marginal increase on the Metro zone (to the extent needed for the two approaches to be revenue neutral).

Consequently, GasNet proposes (for the four northern zones mentioned above) to calculate tariffs for Longford sourced gas on the assumption that all gas used in the northern zones is sourced from Longford, and to calculate tariffs for Culcairn sourced gas on the assumption that all gas used in the northern zones is sourced from Culcairn. This produces tariffs which it considers more likely to encourage gas flows. The shortfall in revenue is proposed to be allocated to the Metro, Lurgi and Tyers zones and also to the Wodonga, North Hume and Murray Valley zones for gas injected at Culcairn in proportion to the direct operating costs allocated to those zones. In the Metro zone this is equivalent to about a 2 cents/GJ increase in tariffs.

In summary, GasNet is proposing to allocate some costs which its cost allocation model would normally allocate to the northern zones to other zones. The purpose is to produce tariffs in the northern zones which will not discourage gas transportation and recover the shortfall from zones in which a marginal increase in tariffs will not discourage gas transportation.

GasNet claims that the delivered cost of gas in the northern zones, without the proposed adjustment, approaches the cost of alternative fuels, but does not give any evidence for this. It also claims that the proposed tariffs are above the zones' marginal cost but again does not provide evidence. The Commission notes that no submissions from interested parties dealt with this issue.

The question then is whether it is fair and reasonable for the majority of users, who are in the zones with low tariffs, to pay some of the costs attributable to users in the zones with high tariffs, in order for those users in the higher tariff zones to face tariffs which will encourage greater use of the system. The Commission considers that there is insufficient evidence available to it at this time to indicate that the proposed modification will not satisfy the principles of the Code. Accordingly, the Commission proposes not to oppose GasNet's proposal. However, it will consider further submissions on this issue.

GasNet proposes to offer a matched withdrawal tariff to customers who withdraw gas which is injected at Pakenham from three specific connection points in the Metro zone (near Pakenham). This proposal is effectively a prudent discount as it is designed to counter a potential bypass opportunity. It is dealt with in the section *Prudent discounts* below.

The Commission acknowledges GasNet's intention to prepare an amendment to the proposed access arrangement to allow a VicHub trader and a withdrawing retailer to confirm a matching arrangement and considers this appropriate.[300]

Cross-system tariff

As noted above, the Lurgi, Tyers, La Trobe, West Gippsland and Southwest withdrawal zones have withdrawal tariffs which reflect the cost of gas transported from their nearest injection point. GasNet proposes that when gas is not sourced from the nearest injection point, an additional tariff should apply to reflect the additional use of the system.

The Commission understands the concept behind this tariff to be that the gas under question would contribute to the physical volumes flowing from the injection zone to the Metro zone. Contractually, and conceptually, this gas would flow further, although not physically. GasNet intends, therefore, to charge users an amount similar to the Metro withdrawal tariff to match the tariff to the use of the system. GasNet states that the tariff 'will be the Metro zone tariff discounted for the indirect cost allocations (which are already recovered from the withdrawal zones).'[301] TXU considers the tariff is likely to inhibit competitive market development because it adds to transportation costs.[302] However, if the tariff reflects appropriate cost allocation, which in this case the Commission considers it does, then market development should not be hindered.

The Commission notes that for gas flowing from Port Campbell to the La Trobe zone this does not give a total withdrawal charge similar to the Metro tariff. This is because the La Trobe zone is discounted to avoid presenting a bypass opportunity. It may have been more appropriate for there to be a different cross-system withdrawal tariff in this instance, so that the combined withdrawal tariffs equated the tariff for the Metro zone. However, the Commission notes that this would add even more complexity to the tariff structure and does not consider that the potential advantages would outweigh the cost of the added complexity. The Commission therefore proposes to accept the cross-system withdrawal tariff as proposed by GasNet.

Some submissions indicated an anomaly with the cross-system tariff as it applies to the northern zones. GasNet has responded that this tariff is not intended to apply to flows to the northern zones as the costs of transmission through the Metro zone are included in the northern withdrawal tariffs.[303] The Commission agrees with GasNet and considers this appropriate. It notes that while in Schedule 1 of the access arrangement, section 1.5(c) may be ambiguous, section 1.5(d) appears to clarify the situation.[304]

DEI and AGL expressed a concern that GasNet could over recover its revenue requirement through the operation of the cross system withdrawal tariff.[305] As noted in

300 GasNet response to submissions, 12 June 2002, p. 18.

301 GasNet submission, 27 March 2002, schedule 5, p. 46.

302 TXU submission, 31 May 2002, p. 21.

303 GasNet response to submissions, 12 June 2002, p. 11.

304 GasNet access arrangement, 27 March 2002, pp. 21-22.

305 DEI submission, 13 May 2002, p. 3; AGL submission, 9 May 2002, p. 2.

the discussion of overall complexity above, and by GasNet,[306] the K factor operation will not allow GasNet to over-recover revenues by virtue of the application of the cross-system withdrawal tariff.

TXU also considers that the tariff produces a pricing anomaly as it would be cheaper to transport Longford gas to the Southwest Pipeline withdrawal zone than it would be for Port Campbell gas.[307] This would be the case if all the gas was supplied on peak days, which would appear to be an unlikely scenario as the peak days are not known in advance. If supplied all year, the Port Campbell sourced gas is transported more cheaply.[308]

Prudent discounts

GasNet proposes to introduce prudent discounts for:

- the withdrawal tariff at Wodonga for gas matched to injections at Culcairn;
- the withdrawal tariff at three withdrawal points within the Metro zone which are close to Pakenham for gas matched to injections at Pakenham;
- the withdrawal tariff at La Trobe (for all withdrawals: GasNet assumes there are no withdrawals from this zone of gas sourced from anywhere other than Longford); and
- the withdrawal tariff for Warrnambool and Koroit in the Western zone.

In all cases the prudent discount is targeted at existing users who have, or will have, the opportunity to completely bypass the PTS. The basis is that in the absence of the discount the customers in question would not use the system.

A number of interested parties have expressed opposition to this proposal. They consider that the provision of a prudent discount for one customer (or group of customers) would result in other customers paying higher tariffs. It may be that other customers will pay more than they did before the threat of bypass. However, a prudent discount is one which results in other customers paying lower tariffs than they would in the absence of the discount (and consequently the absence of the user targeted by the discount).

The Commission has evaluated the methodology used by GasNet to calculate the bypass tariffs. It agrees with the principles used and considers the input data appropriate. While it does not concur with all the assumptions and calculations made by GasNet, the differences between the Commission's preferred approach and that taken by GasNet generally have little impact on the level of the tariffs calculated. In particular, the Commission's approach would not have the effect of increasing the size of the discount that needs to be offered and therefore recovered from other users. Further, the Commission agrees with GasNet's assessment that in the absence of the prudent discounts there is a significant likelihood that the target users would cease to

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306 GasNet response to submissions, 12 June 2002, p. 11.

307 TXU submission, 31 May 2002, p. 24.

308 19 cents/GJ from Port Campbell compared to 32 cents/GJ from Longford for a customer with 100 per cent load factor.

use the PTS. The Commission proposes to accept the prudent discounts proposed for the second access arrangement period.

TXU believes the prudent discounts for users in Warrnambool and Koroit on the western system should not be offered until the bypass threat is actual rather than perceived.[309] This prudent discount proposal is expressed in terms of it being initiated if 'either the SEA Gas Pipeline or the Southern Gas Pipeline has been commissioned.'[310] The SEA Gas Pipeline is being developed by a joint venture between Origin Energy and Australian National Power. The Commission understands that the Southern Gas Pipeline was a joint proposal by DEI and GasNet but that it is now being proposed by TXU.[311]

The Commission acknowledges that either of these proposed pipelines may pose a by-pass threat affecting parts of the western system. Whether this would be the case would depend on both the likely associated costs and the commercial strategies of the proponents. It is not clear that introduction of a prudent discount should be triggered automatically by the commissioning of either pipeline without taking other factors into account. The Commission considers that evidence would be needed that a specific by-pass threat is credible before prudent discount is triggered. Accordingly the Commission has proposed an amendment to require GasNet to provide sufficient evidence to establish that a by-pass threat is credible.

Proposed amendment 26

GasNet must amend clause 1.3(f), schedule 1 of its revised access arrangement to require the provision of sufficient evidence to the Commission to support a claim that a specific bypass threat is credible. In addition, it must state that the introduction of the Warrnambool and Koroit prudent discounts would be subject to the Commission's approval.

Origin requests that the access arrangement have the flexibility to allow for future prudent discounts as the need arises, if the new project provides system wide benefits.[312] The Commission considers that this request indicates a misunderstanding of the roll of prudent discounts. If a project has system wide benefits it can be included in the asset base (through section 8.16(b)(ii) of the Code). This will result in all users contributing to its costs. Prudent discounts are appropriate to gain or retain users who would not be users at the proposed tariffs but would be users at lower tariffs which are higher than the incremental cost of servicing those users (in which case the users would contribute to common costs which would result in lower tariffs for other users).

Origin also suggested that a prudent discount is also appropriate for withdrawals from the WUGS to the proposed SEA Gas pipeline and from the Longford plant to the EGP at the VicHub.[313] GasNet has indicated that it is willing to work with VENCorp to

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309 TXU submission, 31 May 2002, p. 4.

310 GasNet access arrangement, schedule 1, clause 1.3(f).

311 'TXU to build $360 million pipeline', *Australian Financial Review*, 15 July 2002, p. 15.

312 Origin submission, 17 May 2002, p. 5.

313 ibid., p. 4.

design appropriate prudent discounts.[314] The Commission considers it appropriate that GasNet publish its proposal on these two issues, in the form of a submission to this access arrangement process in time for interested parties to also be able to make comments in submissions before the closing date for submissions to the Draft Decision.

It has been suggested in submissions that GasNet and not VENCorp should be the organisation to offer any appropriate discounts. The Commission agrees that it would be simpler for one organisation to offer any prudent discounts required and that GasNet is best placed to do so. Further, to the extent that GasNet would apply the shortfall in revenue to other users in the same way that VENCorp would, users and GasNet should be indifferent to which organisation offers the discount. The Commission understands that users are ultimately concerned with their final delivered price and if this is the same irrespective of the organisation implementing the discounting then users should be unconcerned.

It could be argued that if the discounting would produce a tariff lower than the marginal cost of the user to GasNet then VENCorp should take up the balance of the required discount. However, again, this should produce no different an outcome to users compared to GasNet reducing its tariff below marginal cost in order to implement the whole prudent discount (as long as it allocates the unrecovered costs to other users in the same way that VENCorp would have). In fact, GasNet and users should be indifferent even if the prudent discount were less than VENCorp's tariff, and therefore for GasNet to implement it the GasNet tariff would have to be negative.

None of the prudent discounts assessed above are below marginal cost and thus the concerns addressed in the above paragraph are not immediate. However, it may be that the two situations nominated by Origin will raise these concerns. The Commission looks forward to further input from interested parties on this issue after GasNet and VENCorp make their public response to Origin's suggestion.

Further adjustments

The Commission is continuing to assess GasNet's cost allocation model with respect to whether it implements the procedures described in the proposed revised access arrangement. It may be that, with the amendments the Commission is proposing in this Draft Decision, adjustments will need to be made to some of the detail of the model. The relativities between tariffs may be different to those originally proposed by GasNet.

8.2 Tariff path

8.2.1 Code requirements

Section 8.3 of the Code provides discretion to service providers in how the reference tariffs may be varied during an access arrangement period. For example, tariffs may change according to a price path. That is, tariffs follow a path determined at the start of the period and are not adjusted for subsequent events until the commencement of the

[314] GasNet response to submissions, 12 June 2002, pp. 17-18.

next access arrangement period. The alternative method is a cost of service approach where tariffs are set on the basis of anticipated costs and are adjusted throughout the access arrangement period in light of actual outcomes. The Code also allows variations or combinations of these approaches to be used.

8.2.2 Current access arrangement provisions

The current reference tariff policy (section 5.3 of the access arrangement) states that a CPI-X price path approach consistent with section 8.3 of the Code will apply to the tariffs for the PTS.

An average revenue control is applied to GasNet and each year the tariffs to be charged are altered in accordance with the Tariff Order (Part A of Schedule 5). The average revenue control requirement is that the forecast average transmission tariff (FATT) must be less than the maximum average transmission tariff (MATT). For each year the FATT will be the weighted average of the proposed tariffs, using the latest forecast volumes for the weighting. The MATT calculated each year is the average transmission tariff (ATT) for that year (as determined in 1998 and adjusted by CPI-X for each year since) less K. The X factor is a smoothing mechanism (not a productivity factor) and was set at 2.7 per cent for the initial access arrangement period. The K factor is a correction factor that aims to correct for any differences in revenue resulting from differences between forecast and actual product mix.[315]

Following the calculation of the maximum average transmission tariff for the forthcoming year each individual tariff can be adjusted. The maximum increase that can be applied to any individual tariff is CPI+Y where Y was set at –1.7 per cent for the initial access arrangement period. This has the effect of limiting the ability of GasNet to move away from the cost reflective tariffs that were accepted by the Commission in 1998.[316]

Consequently, at each year the average tariff for the PTS is calculated with reference to the average tariff set at the start of the access arrangement period, CPI, X and the difference in revenue resulting from differences between actual and forecast product mix (K). Each individual tariff can be altered subject to the re-balancing control (Y). As a result, at the conclusion of year seven (when the full K factor impact for the initial access arrangement period has flowed through to tariffs) it would be expected that GasNet would have obtained the average revenue determined as appropriate by the Commission in 1998.

The Tariff Order also sets out, at clause 9.2, a number of fixed principles to apply for the duration of the subsequent access arrangement. These include:

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315 Product mix refers to the balance of usage between Tariff V and Tariff D customers within zones, the balance between zones and the balance between peak and anytime demand. A change (between forecast and actual usage) in the proportions of any of these categories will affect the average revenue achieved.

316 It effectively means that no tariff can be increased more than one percentage point above the CPI-X increase.

- utilise incentive-based regulation adopting a CPI-X approach and not rate of return regulation; and
- set the X factor in the CPI-X formula so that only one X factor applies without revision for the entire subsequent access arrangement period.

8.2.3 GasNet proposal

In general, GasNet is proposing to retain the existing approach which it regards as a price path approach. That is, tariffs are determined for the initial year of an access arrangement period and then move according to the price control formula mechanism in accordance with schedules 3 and 4 of the access arrangement. It considers that the use of a price path constitutes an incentive mechanism and exposes GasNet to both volume and cost risk.[317]

GasNet also proposes to retain the average revenue control mechanism. However, there are some differences that it proposes for this new access arrangement period which are outlined in the following discussion.

Schedule 3 of the proposed revised access arrangement sets out the process to be followed by the Commission and GasNet for the annual tariff adjustment. In brief, GasNet is required to submit tariffs for the forthcoming regulatory year (which is 12 months from 1 January) at least 15 business days before the start of that year. The Commission must then assess whether those tariffs comply with the formulae set out in schedule 4 of the access arrangement. Schedule 3 provides the Commission with 15 business days in which to assess GasNet’s proposal. If GasNet has not received a notification from the Commission within 15 business days the Commission is deemed to have approved the proposal.

Schedule 4 of the proposed revised access arrangement sets out the price control formula that would apply for each annual tariff alteration. The schedule provides that the maximum average transmission tariff will move over the access arrangement period according to CPI-PPT where PPT is 4.5 per cent and is the weighted average of the X factors.[318]

The rebalancing control formula used in the subsequent calculation of individual tariffs allows any individual tariff to increase by up to two percentage points more than the increase in MATT provided that overall MATT remains unchanged. This is a significant change over the formula in the current access arrangement. First, the current formula only allows a one percentage point difference. More significantly, the current formula allows individual tariffs to be one percentage point above the rise in ATT, not MATT. This created the K factor revenue under-recovery discussed in section 6.2.2.

An X is also identified for each individual tariff in schedule 1 of the proposed revised access arrangement. Many individual tariffs have an X of five per cent. However, a

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317 GasNet access arrangement information, 27 March 2002, p. 30.

318 The formula used is $(1+CPI)\times(1-X)$. GasNet access arrangement, 27 March 2002, p. 34.

number of tariffs have an X factor of zero. As a result, the weighted average X factor for all tariffs is 4.5 per cent. The tariffs with a zero X are:

- injection at Port Campbell and Dandenong;
- withdrawal at Murray Valley and for storage at LNG and WUGS;
- matched withdrawal at Murray Valley, Wodonga and Pakenham; and
- prudent discount tariffs for withdrawals in the Western zone.

Clauses 4.9 and 4.10 of the proposed revised access arrangement allow GasNet to amend tariffs within the access arrangement period for pass through events and the alteration of tariff zones. These clauses are discussed in detail in chapter 3 of this Draft Decision.

8.2.4 Submissions

A number of submissions expressed concern at the tariff path proposed by GasNet for the forthcoming access arrangement period. ENERGEX stated:

> An increase of 11% in real terms is frankly unacceptable in a commercial climate where industry, governments and the community is seeking efficiency gains from infrastructure owners.[319]

A similar view was expressed by Pulse who suggested that the lump sums associated with efficiency gains and the K factor should be treated as annuities to avoid steps in the tariff path.[320]

TXU also regards the proposed tariff path as unacceptable, noting it was ‘surprised’ at the proposal. In particular, TXU suggested that ‘the Commission should consider making it a precondition of approving the GasNet access arrangement on the basis that the Reference Tariffs reflect a smooth transitional from the current level in 2002 to the level required by 2007’.[321]

In addition, Origin does not regard the proposed tariff path as appropriate for a regulated business. It understands that the tariff path for the forthcoming period ‘reflects a view that tariffs in the third access period will be much lower and are designed to avoid a “price shock” in the transitional year between the end of the second access period and the start of the third access period’. Origin regards this as inconsistent with the proposed price shock for the first year of the forthcoming period and considers that a 38 per cent increase in tariffs will have a substantial impact on the market.[322]

EnergyAdvice has calculated tariffs on the basis of GasNet’s proposal for customers located in various zones and with different load profiles. On this basis EnergyAdvice

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319 ENERGEX submission, 9 May 2002, p. 5.

320 Pulse submission, 16 May 2002, p. 5.

321 TXU submission, 31 May 2002, p. 33.

322 Origin submission, 17 May 2002, p. 8.

states that the average effect of GasNet's proposals across zones is an increase in tariffs of approximately 26 per cent in the first year.

EnergyAdvice also commented that 'the impact of the significant price shock is not only prohibitive to new cogeneration projects but also adds considerably to the marginal cost of gas fired generation'.[323]

More specifically, DEI has estimated that the proposed changes to tariffs will result in an effective increase of up to 171 per cent for gas injected into the PTS at Longford. DEI notes that 'given there has been no, or little, augmentation on this section of the network, this increase does not seem warranted'.[324]

8.2.5 Commission's considerations

GasNet has described its form of regulation as a price path approach. This method provides a service provider with incentives to out perform the forecasts that are used in establishing the price path.[325] However, GasNet has modified its price path, which can generally be thought of as a CPI-X mechanism, to accommodate some actual events within the access arrangement period. This is done firstly by the K factor, which ensures that GasNet has the opportunity to achieve the average revenue set at the start of the access arrangement period. In addition, GasNet has proposed a pass through mechanism that extends to a number of costs that may alter within the period. Both these mechanisms reduce the incentive benefits of the initial price path approach established by CPI-X. In fact, the pass through mechanism is an element of a cost of service approach. As a result, it would appear to be incorrect to suggest that that GasNet has established a true price path approach and is subject to the incentives suggested by this description. It would be more correct to describe GasNet's approach as complying with section 8.3(c) of the Code, that is, a combination of a price path and cost of service approach.

As noted above, the Tariff Order established a number of fixed principles for this next access arrangement period. Fixed principles can only be changed with the agreement of the service provider. However, as GasNet has not proposed to alter any of the fixed principles, the proposed revised access arrangement must also comply with these principles.

The first principle of relevance noted above is the requirement to use a CPI-X approach and not a rate of return approach. While GasNet has proposed to modify its price path mechanism further with the introduction of an expanded pass through mechanism, the basis of regulation for GasNet remains CPI-X. The approach has not been altered to the extent that it could be accurately described as rate of return. The Commission is satisfied that GasNet has complied with the fixed principle.

The second fixed principle is that only one X factor is to apply throughout the entire access arrangement period. The Commission interprets this principle as requiring an X

323 EnergyAdvice submission, 30 May 2002, p. 9.

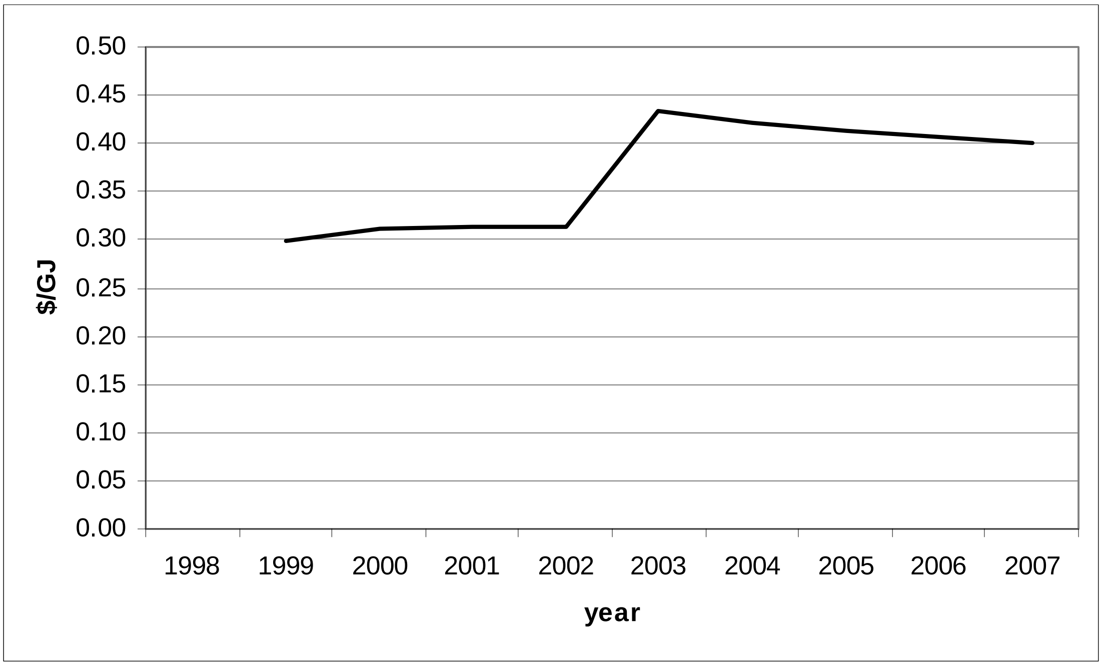
324 DEI submission, 13 May 2002, pp. 3-4.

325 One pipeline that has price path approach in this sense is the Central West Pipeline.

to be set for the whole period and not vary year to year within the period. GasNet has proposed an X of zero for some tariffs and five per cent for other tariffs. This does not conflict with the fixed principle as these X factors are constant over the entire period. The Commission considers that GasNet has complied with the fixed principle.

The tariff path for the ATT for 2003 to 2007 reflects the revenue requirement, or target revenue, established by GasNet in its proposal. In addition to the movement of tariffs within the access arrangement period, there is a step in the average tariff from 2002 to 2003. This change largely reflects GasNet’s proposed increase in revenues based on the proposed change in the capital base and an increase in the rate of return to 8.22 per cent. As illustrated in the figure below, the change from 2002 to 2003 is significant, approximately 38 per cent.

Figure 8.1: Nominal average transmission tariff path, 1998 to 2007



Source: GasNet access arrangement information, 27 March 2002, p. 15; GasNet submission, 27 March 2002, p. 104; TPA access arrangement information, 30 November 1998, p. 17; ACCC analysis.
Note: For 1998 to 2002 the FATT is illustrated. For 2003 to 2007, the ATT is illustrated.

The figure above indicates the change in average tariffs. Customers in different zones will experience significantly different changes in their tariffs between 2002 and 2003. For example, customers with a 50 per cent load factor in the Metro, Wodonga, South Hume and Carisbrook zones will incur an increase. Users with the same load factor in the zones Tyres, Lurgi, Echuca and Latrobe will experience decreases (between 20 and 50 per cent).

It should also be noted that the change in tariffs also varies according to the load factor of the user. In comparison to the changes noted above, if a load factor of 100 per cent is assumed, increases occur in Metro, North Hume, Wodonga, South Hume and Murray Valley. Only Murray Valley Tariff D users will experience an increase less than 40 per cent.

The difference in the proposed tariff change between 2002 and 2003 suggests that the greater burden of recovering the proposed increased revenue is to fall on users with high load factors. This will tend to be Tariff D users. This was discussed in section 8.1.5 above.

As a consequence of various amendments proposed by the Commission the revenue requirement is less than that proposed by GasNet. As a result, GasNet's proposed tariff path is inappropriate. The Commission must consider what tariff path would be appropriate and meet the requirements of the Code in light of the revised revenue requirement.

In general, the Commission would be reluctant to accept any tariff path of the shape proposed by GasNet, that is, a large initial increase followed by a substantial fall over the second access arrangement period. It appears from submissions received that the proposed tariff path is a concern to users and other interested parties.

The Commission considers that there are three aspects that must be considered when determining an appropriate tariff path. These are:

- the initial change in tariffs (for GasNet this is the change between 2002 and 2003);
- the movement of tariffs within the period (as indicated by X); and
- the change in tariffs at the end of the period moving into the subsequent period (for GasNet this the change from 2007 to 2008).

It appears that GasNet has been particularly concerned with the third aspect to the detriment of the others.[326]

The Commission acknowledges the desirability of a smooth transition between the tariffs for 2007 and 2008 (a reason GasNet gave for its proposed tariff path). However, a smooth transition between 2002 and 2003 and the slope of the path are also important considerations. Consequently, a balance between the three aspects of the tariff path must be found.

The reduced revenue requirement proposed by the Commission for GasNet would reduce the initial tariff increase by approximately half (if the same X values are assumed). However, it could be reduced further by applying a shallower tariff path while still providing the same revenue requirement over the access arrangement period. If this adjustment is undertaken then a tariff path with a less pronounced initial increase can be achieved as illustrated in Figure 8.2 below.

This particular tariff path illustrated below has an initial tariff change between 2002 and 2003 of approximately 4 per cent. Tariffs follow a CPI-X path over the subsequent year with an X factor of 2 per cent and inflation assumed to be 2.5 per cent. An indicative estimate of the tariff movement between 2007 and the estimated tariff for 2008 is a fall of approximately 14 per cent.

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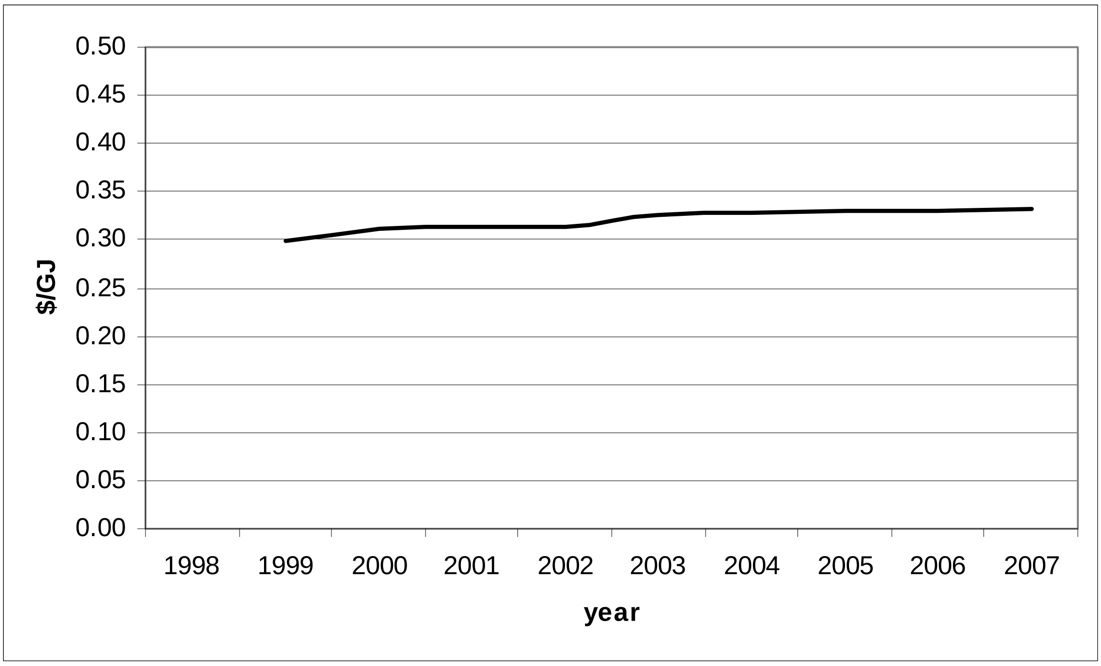
326 Although it states that it has selected an X 'which it believes reasonably balances the tariff changes at the commencement of the next and the subsequent Access Arrangement Periods'. GasNet response to submissions, 12 June 2002, p. 10.

In selecting this tariff path the Commission has placed a little more weight on limiting the extent of the initial tariff movement and extent of the slope of the path within the period. This is because the target average tariff for 2008, and consequently the end period tariff change, is the least certain element.

Figure 8.2: Nominal indicative average transmission tariff path, 1998 to 2007



Source: GasNet access arrangement information, 27 March 2002, p. 15; GasNet submission, 27 March 2002, p. 104; TPA access arrangement information, 30 November 1998, p. 17; ACCC analysis.

An alternative tariff path for the same revenue requirement could reduce the end period tariff movement below 14 per cent. For example, with an initial tariff increase of 12 per cent and an X of 6 per cent an end period tariff movement of less than 1 per cent could be obtained. However, the Commission would find a tariff path of this shape less desirable than the tariff path mentioned above.

The Commission notes that GasNet has proposed that some tariffs move within the access arrangement period according to an X of 5 per cent while others have an X factor of zero. In light of the proposed amendments, the Commission would expect that GasNet could appropriately apply a single X factor to all reference tariffs.

Accordingly, GasNet can establish a forecast average tariff path for the period 2003-2007 that produces a small nominal increase in the average tariff over the period with a limited initial increase (between 2002 and 2003).

As noted above, GasNet proposed amendments to the annual tariff assessment process. No submissions were received on these issues. However, the Commission does propose some amendments to these proposed revisions.

The proposed schedule 3 of the access arrangement provides 15 business days for the Commission to assess an annual tariff proposal from GasNet. The current provisions contained in the Tariff Order state that GasNet must provide its proposal at least 30 business days prior to the commencement of the new regulatory year. The Commission then has 20 business days in which to assess the proposal and notify GasNet of its decision. In the Commission's experience the current time frames are adequate and appropriate but a reduction would limit the Commission's ability to adequately assess the proposed changes. Accordingly, the Commission has proposed the following amendment to the effect that the current time frames as specified in the Tariff Order are included in the proposed schedule 3 of the revised access arrangement.

Proposed amendment 27

GasNet must amend schedule 3 to its revised access arrangement so that the annual tariff review time frames currently in clause 6.1 of the Tariff Order are retained.

Chapter 6 of the Tariff Order includes provisions to the following effect:

- the annual tariff statement must set out the proposed tariff components for each of the tariffs (clause 6.1(a)(1)(B)); and
- the Commission must approve an annual tariff statement if all the forecasts included in the statement are satisfactory to the Commission (clause 6.1(f)(2)).

The Commission notes that schedule 3 of the proposed revised access arrangement does not include these provisions. The Commission considers that the annual assessment of tariffs requires sufficient information on tariff components to allow a full assessment to be undertaken and that this should be provided. In addition, if GasNet is to retain the ability to update forecasts within an access arrangement period rather than use the initial forecast data for the entire access arrangement period then the Commission requires discretion to determine whether the new forecasts are appropriate to use. Accordingly, the Commission proposes the following amendment to the proposed revised access arrangement.

Proposed amendment 28

GasNet must amend schedule 3 of its revised access arrangement to include the provisions currently in clauses 6.1(a)(1)(B) and 6.1(f)(2) of the Tariff Order.

8.3 Compliance with tariff principles

8.3.1 Code requirements

Section 3.5 of the Code requires the access arrangement to include a policy describing the principles that are to be used to determine a reference tariff (a reference tariff policy). This reference tariff policy must, in the regulator's opinion, comply with the reference tariff principles set out in section 8 of the Code.

The reference tariff policy and reference tariffs should be designed to achieve a number of objectives that are outlined in section 8.1 of the Code:

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

(b) replicating the outcome of a competitive market;

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

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

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

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

To the extent that there may be conflict in applying these objectives, the regulator has the responsibility to determine how they may be reconciled.

In addition, section 8.2 stipulates that when approving a reference tariff and reference tariff policy the regulator must be satisfied that:

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

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

(c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service (referred to in paragraph (b)) is recovered from the Users of that Reference Service consistently with the principles contained in this section 8;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this section 8; and

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

The reference tariff principles outlined in sections 8.1 and 8.2 are designed to provide flexibility so that reference tariffs and reference tariff policies can be designed to meet the specific needs of each pipeline. However, the overarching requirement is that reference tariffs should be based on the efficient cost (or anticipated efficient cost) of providing the reference services.

8.3.2 Commission's considerations

The Commission considers that GasNet has complied with section 3.5 of the Code in providing a reference tariff policy in the access arrangement. A discussion on the reference tariff policy and the reference tariff methodology is located at chapter 3 of this Draft Decision.

As noted above, each of the aspects of the reference tariff and reference tariff policy has been assessed in the relevant sections of this Draft Decision. The following discussion draws together the Commission's conclusions within the framework of sections 8.1 and 8.2 of the Code.

As noted in section 1.2 of this Draft Decision, pursuant to section 2.46 of the Code, the Commission must also take the factors set out in section 2.24 and the provisions of the access arrangement into account when assessing proposed revisions to an access arrangement. The Commission has given due consideration to each of these factors in assessing GasNet's proposed reference tariff and reference tariff policy (and the other elements set out in sections 3.1 to 3.20 of the Code). The following discussion also specifically comments on some of these factors in respect of the reference tariff and reference tariff policy.

Section 8.1 objectives

Recovery of efficient costs associated with the provision of reference services (8.1(a))

The Commission has assessed the proposed rate of return (see chapter 5 of this Draft Decision) and determined that it is not appropriate and does not reflect an efficient, commercial return on GasNet's investments. The Commission has also considered capital and non-capital costs proposed by GasNet. Many of these costs have been determined as not unreasonable costs for a prudent service provider. However, a number of adjustments are proposed to particular cost categories.

If GasNet adopts the proposed amendments contained in this Draft Decision then the reference tariffs will generate a revenue stream that will be more comparable with the efficient costs of providing the reference service and satisfy both section 8.1(a) and 2.24(d) of the Code. Recovery of efficient costs is consistent with the service provider's legitimate business interests and investment in the covered pipeline (section 2.24(a)) and the interests of users and prospective users (section 2.24(f)).

Replicating the outcome of a competitive market (8.1(b))

Setting the regulated rate of return of CAPM benchmarks results in a return that is expected to be similar to those achieved by firms facing similar commercial risks operating in a competitive environment. The return will be based on only those assets necessary to deliver the services required.

The reference tariffs will also allow GasNet to achieve a return in excess of a normal return from increased efficiencies and growth in sales, as occurs in a competitive market. However, over time, as in a competitive market, this benefit will pass onto customers. The Commission has proposed the efficiency carryover mechanism to encourage efficiencies and ensure that they are shared appropriately.

Efficiency and equity considerations generally support a tariff path with a levelised real tariff over time, or one that declines slightly in real terms to reflect declining costs relative to output. The Commission's modeling of tariffs indicates that such a tariff structure is achievable for GasNet (see section 8.2 of this Draft Decision).

Pricing reflective of efficient costs is also a feature of competitive markets and the Commission aims to ensure that tariffs are reflective of efficient costs to the extent that this is practicable.

There are some changes to the cost allocation and tariff structure for 2003-2007 in comparison to the initial access arrangement period. As indicated in section 8.1.5 of this Draft Decision, the Commission is seeking further information regarding these aspects of GasNet's proposed revised access arrangement. However, with the adoption of the proposed amendments contained in this Draft Decision, the Commission anticipates that section 8.1(b) of the Code is likely to be satisfied.

Ensuring the safe and reliable operation of the pipeline (8.1(c))

The reference tariffs are based on cost forecasts as being necessary for the safe and reliable operation of the pipeline. Each review of the access arrangement provides an opportunity for GasNet to increase its revenue if the safety and reliability of the pipeline demands it. GasNet may also submit early revisions to the access arrangement if desired. Other factors that will tend to preserve the integrity of the system include the contractual arrangements between GasNet and VENCorp to maintain the SEA.

The Commission regards that with the amendments required in this Draft Decision the proposed costs for the PTS will remain appropriate for the safe operation of the pipeline system as required under section 8.1(c) and 2.24(c) of the Code.

Not distorting investment decisions (8.1(d))

Efficient investment decisions upstream and downstream will be facilitated by transmission pricing based on an allocation of costs to users which approximates long run costs of providing the service.

Efficient investment decisions will also follow an appropriate rate of return which is neither excessively high so as to encourage over investment and not so low as to discourage efficient investment.

The return should be considered in conjunction with other aspects of the access arrangement to understand the full regulatory framework in which the business operates. In the case of GasNet, over investment is unlikely to be encouraged because of the redundant capital policy provisions in the access arrangement.

In addition, the extensions and expansions policy will provide GasNet with complete discretion regarding the coverage of extensions, giving it complete flexibility to meet the needs of a growing market and earn returns greater than the benchmark nominated by the Commission.

GasNet has raised concerns regarding potential bypass situations that may arise in the future. The Commission considers that the access arrangement provides GasNet with the flexibility to manage these events as they occur. This includes the use of the extensions and expansions policy, the ability to use prudent discounts, the redundant capital policy and its depreciation schedule.

Accordingly, the Commission considers that with the proposed amendments in place, the revised access arrangement will not have a tendency to distort investment decisions in the wider market or in regard to the PTS.

Efficiency in the level and structure of reference tariffs (8.1(e))

As noted above, the Commission has requested additional information about some of the proposed revisions from GasNet relating to the allocation and recovery of costs. On this basis of the information currently available, and the proposed amendments, the Commission expects that this aspect of the Code will be satisfied.

A number of proposed amendments to the costs forecast by GasNet has been made by the Commission. If these amendments are adopted the Commission considers that the level of tariffs, on average, will be more appropriate.

The Commission does not consider the proposed tariff path is appropriate or meets the Code principles. In response to concerns from interested parties, the Commission has proposed that the tariff path be smoothed, to the extent practicable, over the access arrangement period.

Incentives to reduce costs and expand the market (8.1(f))

GasNet's average revenue control mechanism and use of forecast costs provide an incentive to develop the market for gas and achieve efficiencies in operations and maintenance and capital expenditures.

The Commission considers that the adoption of the rolling carryover approach for operations and maintenance costs will continue to provide GasNet with the initial benefits of achieving efficiencies while ensuring that the benefits are passed onto users in the longer term.

In addition, the Commission has accepted specific costs for market development by GasNet.

The Commission considers that the proposed amendments should be adopted by GasNet to meet the requirements of the Code.

Section 8.2 factors

Total revenue is established consistently with the principles and according to one of the methodologies contained in section 8 of the Code (8.2(a))

Total revenue is to be determined by either the cost of service, IRR or NPV methods. GasNet has adopted a Cost of Service approach with the use of a cost of service/price path approach to determine the movement of reference tariffs within the access arrangement period.

This approach is permitted by section 8 of the Code and the Commission concludes that GasNet has satisfied this requirement of the Code.

The proportion of total revenue that any one reference tariff is designed to recover is calculated consistent with the principles of section 8 of the Code (8.2(b))

As noted above, the Commission has requested further information regarding the allocation of capital and non-capital costs to the various reference tariffs. It has also stated that the proposed allocation method for the K factor under-recovery and capital raising costs are not appropriate and must be amended.

With the adoption of the proposed amendments the Commission anticipates that this Code principle will be satisfied. It considers that tariffs that are reasonably cost reflective are in the interests of users and prospective users (section 2.24(f)).

The proportion of total revenue recovered from users of a service is calculated consistent with the principles of section 8 of the Code (8.2(c))

Among the Commission's concerns regarding tariffs is the allocation of costs between Tariff V and Tariff D users and GasNet's application of peak pricing. The Commission must also consider the proposed matched rebates and prudent discounts and their impact on users across the system. A number of aspects of the tariff and cost allocation proposal require clarification and further information. However, the initial conclusion is that the recovery of revenues from users is likely to be consistent with the principles of the Code.

Incentive mechanisms that are incorporated are consistent with the principles of section 8 of the Code (8.2(d))

The Commission has carefully assessed GasNet's proposed incentive mechanism and has determined that it does not fully meet the objectives of the Code. The Commission has proposed some changes, most significantly, the adoption of the rolling carryover mechanism for operations and maintenance costs. With the adoption of these amendments, the Commission would consider that this aspect of the revised access arrangement is likely to meet the relevant principles of the Code.

Forecasts are best estimates determined on a reasonable basis (8.2(e))

The Commission has proposed a number of amendments to the forecast operations and maintenance costs, other non-capital costs and capital costs for 2003-2007. It has also proposed that GasNet amend its volume forecasts (see chapter 7 of this Draft Decision) to include more recent events and revised market expectations.

These amendments would result in the access arrangement using the best estimates available on a reasonable basis and meeting this particular Code objective.

Conclusion

This chapter of the Draft Decision requests some additional information from interested parties and GasNet in relation to cost allocation and tariff structure. In addition, a number of amendments have been proposed.

At this point the Commission expects that with the adoption of the proposed amendments, the Code principles contained in sections 8.1, 8.2 and 2.24 will be met.

Part C – Non tariff issues

9. Access arrangement information

9.1 Code requirements

The service provider's access arrangement information must contain sufficient information in the opinion of the relevant regulator to:

- enable users and prospective users to form an opinion as to the compliance of the proposed revised access arrangement with the provisions of the Code (section 2.6); and
- understand the derivation of the elements in the proposed revised access arrangement described in sections 3.1 to 3.20 of the Code (section 2.6).

According to section 2.7 of the Code, the access arrangement information provided may include any relevant information, but must at least contain the categories of information described in Attachment A to the Code, which is summarised in Figure 9.1 below.

Figure 9.1: Summary of Attachment A information

The information required is divided into six categories:

Category 1: access and pricing principles
Tariff determination methodology; cost allocation approach; and incentive structures.

Category 2: capital costs
Asset values and valuation methodology; depreciation and asset life; committed capital works and planned capital investment (including justification for); rates of return on equity and debt; and debt/equity ratio assumed.

Category 3: operations and maintenance costs
Fixed versus variable costs; cost of services by others; cost allocations, for example, between pricing zones, and cost categories.

Category 4: overheads and marketing costs
Costs at corporate level; allocation of costs between regulated and unregulated segments; cost allocations between pricing zones, services or categories of asset.

Category 5: system capacity and volume assumptions
Description of system capabilities; map of piping system; average and peak demand; existing and expected future volumes; system load profiles and customer numbers.

Category 6: key performance indicators

Indicators used to justify 'reasonably incurred' costs

Under section 2.8 of the Code, information included in the access arrangement information may be categorised or aggregated. The extent to which it may be categorised or aggregated is that which is necessary to ensure that disclosure of the information is, in the opinion of the relevant regulator, not unduly harmful to the legitimate business interests of the service provider, a user or prospective user.

If the regulator is not satisfied that the access arrangement information meets the requirements of the Code, it may require the service provider to make changes to the access arrangement information. Likewise, if requested to do so by any person, the regulator must review the adequacy of the access arrangement information. However, the regulator must not require the inclusion of material the release of which, in the regulator's opinion, could be unduly harmful to the legitimate business interests of the service provider or of a user or prospective user (section 2.9).

If the regulator requires the service provider to change the access arrangement information, it must specify the reasons for its decision and allow the service provider reasonable time to make the changes and to resubmit the access arrangement information.

This chapter relates specifically to access arrangement information provided for users and prospective users. The regulator also has wider information-gathering powers under the GPAL. That Law gives the regulator power to require a person to give the regulator information or a copy of a document. The power can be exercised if the regulator has reason to believe that a person has information or a document that may assist the regulator in the performance of any of the regulator's prescribed duties under the Law. Section 2.8 of the Code states that nothing in that section limits the regulator's power under the Law to obtain information, including information in an uncategorised or unaggregated form. The Code and the Law place separate limitations on the regulator's discretion to disclose information received that has been identified as being of a 'confidential or commercially sensitive nature'.

These statutory powers aside, the Commission values the cooperation of the service provider and other interested parties in making information available in response to the numerous queries that inevitably arise in considering complex matters.

9.2 Current access arrangement information

When the Commission approved the PTS and WTS access arrangements in 1998 it concluded that the accompanying access arrangement information, as amended and supplemented, satisfied the requirements of sections 2.6 and 2.7 of the Code and sufficient data with respect to all the categories listed in Attachment A to the Code had been provided. This information is available from the Commission's website (www.accc.gov.au).

9.3 GasNet proposal

GasNet submitted revised access arrangement information in support of its proposed revised access arrangement. In addition, it provided a detailed supporting submission which included nine schedules and 12 annexures. Of these, GasNet initially claimed confidentiality for seven annexures but subsequently agreed that six should be released publicly. In addition, GasNet provided additional clarification and information in the form of Errata and information regarding the Murray Valley Pipeline. This information is available from the Commission's website (www.accc.gov.au).

9.4 Submissions

A number of parties reported difficulties in understanding the information provide by GasNet in either general terms or specifically with respect to the derivation of the elements of the proposed access arrangement or in forming an opinion as to its compliance with the provisions of the Code.[327]

TXU stated that it found the approach taken by GasNet of providing most of its supporting information in a separate submission with additional schedules and annexures to be 'particularly complex' and suggested that GasNet should resubmit its application in a simpler and clearer form that substantiates the proposed changes.[328]

ENERGEX believes that it is not possible to understand the relationship between the GasNet and VENCorp access arrangements without access to the SEA and that it should be made publicly available.[329] ENERGEX also requested that non-financial information relating to arrangements between GasNet and incumbent retailers with respect to the WTS be made available. Further, ENERGEX considers that the absence of historic data on operations and maintenance expenditure makes it 'difficult, if not impossible for participants to make cogent assessment of the veracity of the substantive proposals for price increases.'[330]

BHP Billiton requested that the Commission review the adequacy of the access arrangement information provided by GasNet pursuant to section 2.30(b) of the Code. Similarly, TXU stated that it believes that GasNet has not satisfied the requirements of sections 2.6 and 2.7 of the Code, and suggested that the Commission 'request GasNet to resubmit its access arrangement.[331] The EUAA also requested that the Commission review the adequacy of the access arrangement information provided by GasNet in relation to sections 2.6 and 2.7 of the Code.[332] BHP Billiton and EUAA also requested that the Commission review GasNet's confidentiality claims regarding annexures to its submission.

9.5 Commission's considerations

The Commission notes that GasNet provided extensive documentation in support of its proposed revisions. It also notes the difficulties expressed by interested parties in understanding the application. These difficulties largely reflect the large number of revisions proposed by GasNet and their complexities. However, the Commission is concerned that the format adopted by GasNet has added to these difficulties. It would be preferable if the proposed revised access arrangement information could be read as a stand-alone document. In practice it must be read along with GasNet's submission

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327 TXU submission, 3 May 2002, pp. 1-2; ENERGEX submission, 9 May 2002, p. 6; BHP Billiton submission, 17 May 2002, pp. 3-8.

328 TXU submission, 3 May 2002, p. 1.

329 ENERGEX submission, 9 May 2002, p. 6.

330 ibid., p. 6.

331 TXU submission, 31 May 2002, p. 39.

332 EUAA submission, 4 June 2002, pp. 1-2.

(including its schedules and annexures) as it contains information needed to allow a reasonable assessment of the proposals. The Code makes no specific provision that access arrangement information be provided in a single document. The Commission proposes to accept the inclusion of access arrangement information in two documents. GasNet may choose to consolidate this information. Otherwise, its documents will be considered to together form the access arrangement information.

The Commission is also concerned that parties have reported difficulties in understanding aspects of GasNet's proposals. These difficulties have been evident from misunderstandings expressed in submissions about GasNet's proposals.

The Commission has considered this suite of documents in its assessment of the access arrangement information's compliance with the provisions of the Code on its own volition (section 2.30(a)) and in response to BHP Billiton's request (section 2.30(b)) and formed the view that the following information may be needed to satisfy the requirements of sections 2.6 and 2.7 of the Code:

- addition of KPI information in terms of operations and maintenance costs/TJ/km;
- historical operations and maintenance expenditure (for the first access arrangement period); and
- data in support of GasNet's proposed inclusion of the Murray Valley Pipeline in its asset base.

This assessment required the Commission to consider the level of detail needed to satisfy the condition of the Code that the access arrangement information should contain sufficient information to allow users and prospective users to understand the derivation of the elements of the access arrangements and to form an opinion as to whether the proposed revised access arrangement would comply with the provisions of the Code.

GasNet queried the need to provide additional access arrangement information. Primarily at issue is whether service providers only need to provide sufficient information to allow users and prospective users to understand the methodology used (for example, allocation of costs), or whether users and prospective users are given sufficient financial data to allow them to replicate the service provider's tariff calculations. The Commission considers that the Code does not require the service provider to provide publicly sufficient information to enable users and prospective users to replicate the service provider's tariff calculations. It does, however, require that the regulator be able to replicate these calculations. Sufficient information has been provided to the Commission to form this assessment. It also requires that users and prospective users be able to form an opinion as to compliance with the provisions of the Code.

The need for additional KPI data is discussed in section 10.2.5 of this Draft Decision and an amendment is proposed. GasNet provided data in relation to the Murray Valley Pipeline to the Commission on 1 August 2002. The Commission has considered whether to delay release of this Draft Decision in order to allow additional time for interested parties to comment on this information. However, while the information is important, the Commission is cognisant of the need to expedite the review process. Interested parties should consider this additional information carefully when responding to this Draft Decision.

The Commission has considered concerns raised by ENERGEX that the following information has not been disclosed: the SEA; certain information relating to the WTS; and historic data on operations and maintenance. The Commission notes that the SEA is publicly available from its website. It expects that a revised version will be similarly available once details regarding the WTS have been incorporated. However, it is not aware of any basis under the Code for pursuing ENERGEX's request for disclosure of non-financial information relating to arrangements between GasNet and incumbent retailers with respect to the WTS.

The Commission shares ENERGEX's concerns about the difficulty that interested parties would have in reasonably assessing GasNet's tariff proposals in the absence of historic data on operations and maintenance expenditure. Accordingly, it advised GasNet of its view that this information should be publicly available. GasNet responded that it does not consider that this information should be published:

> This data has been provided to the Commission to assist in its evaluation of our forecast operating cost proposal. However we do not believe that this historical data would be useful to the public in forming a view on our proposals. The historical data is not necessarily a useful guide to future costs, and it is certainly not sufficient to make an informed assessment. In fact, it could potentially mislead the public. For example, the historical data does not include certain governance costs which were borne by GPU and not passed through. In addition, GasNet was obliged to reduce its costs temporarily, and in an unsustainable way, in response to very large revenue shortfalls. On balance, we believe the public should be sufficiently informed by our benchmarking and KPI data, and by a comparison of the previous forecast of operating costs 1999-2002 with the new forecast 2003-2007.[333]

Pursuant to section 7.12 of the Code the Commission must not disclose information for which GasNet has requested confidentiality unless it is of the opinion that disclosure would not be unduly harmful to the legitimate business interests of GasNet or a user or prospective user. The Commission notes that GasNet has not claimed that disclosure would unduly harm the legitimate business interests of any party. It considers that interested parties are capable of understanding GasNet's caveats and that disclosure of this information will assist them to form an opinion as to the compliance of the access arrangement with the provisions of the Code. It does not consider that disclosure of the information would be unduly harmful to the legitimate business interests of GasNet or a user or prospective user. It does consider that the information is needed to form an opinion as to compliance of the revised access arrangement with the provisions of the Code. Consequently, the Commission has disclosed this information as part of its assessments of operations and maintenance costs and of the incentive mechanism.

The Commission also considered BHP Billiton's request that it review GasNet's confidentiality claims regarding seven of the annexures to its submission. As noted earlier, GasNet agreed that six of these should be released publicly. These were placed on the Commission's website in May and June 2002.

GasNet considers that release of Annexure 7 (Valuation of Non-Insured Risks, prepared by Trowbridge) could prejudice its dealings with insurance companies if it were made public as it contains information relating to the value of and need for

[333] GasNet response to Commission, 1 August 2002.

insurance cover of various types. The Commission considers that this report should remain confidential.

GasNet has also provided a range of data as Errata to its submission. These have been included on the Commission's website.

Notwithstanding a general concern raised by a number of parties about the adequacy of the quantity of information provided by GasNet, the Commission notes that GasNet has provided extensive documentation in support of its proposals. This includes some quite detailed schedules (such as schedule 5 to its submission, Tariff Methodology).

Conclusion

The Commission has concluded that, pursuant to sections 2.30(a) and 2.30(b) of the Code that the information provided by GasNet in its access arrangement information and submission generally satisfies the requirements of sections 2.6 and 2.7 of the Code. However, it considers that GasNet's historical operations and maintenance costs should be included in the access arrangement information as this will assist interested parties to form an opinion as to the compliance of the access arrangement with the provisions of the Code. Inclusion of additional KPI data will also assist interested parties to form an opinion on compliance. In addition, GasNet must submit revised access arrangement information as a consequence of amendments proposed in this Draft Decision.

Proposed amendment 29

GasNet must amend section 3.5 of the access arrangement information to include actual historical operations and maintenance costs for each of the years 1998 to 2001, and current best estimates for 2002.

10. Performance and incentives

10.1 Incentive mechanisms

10.1.1 Code requirements

Section 8.44 of the Code provides for the regulator, wherever it is deemed appropriate, to require or approve an incentive mechanism. An incentive mechanism enables a service provider to retain some or all of any returns from the sale of a reference service that exceed the expected level of returns. The Code provides for an incentive mechanism to operate during an access arrangement period, or during a period incorporating two or more access arrangement periods. This mechanism is particularly to operate where the increased returns are attributable, at least in part, to the service provider's efforts.

Section 8.46 states that an incentive mechanism should be designed to encourage the service provider to increase sales volumes, minimise costs, develop new services and undertake only prudent new investment and non capital expenditure. The mechanism should be designed to ensure that users gain from any increased efficiency, innovation and improved sales volumes. The mechanism may include:

- specifying the tariff that will apply during the access arrangement period based on forecasts of all relevant variables, regardless of the realised value of those variables;
- specifying a target for revenue and specifying how revenue in excess of this is to be shared between the service provider and users; and
- establishing a rebate mechanism for rebateable services that does not provide a full rebate to users.

10.1.2 Current access arrangement provisions

Provisions relating to incentive mechanisms for the PTS are currently in chapter 9 of the Tariff Order. There are similar provisions in clause 5.3.7 of the WTS access arrangement.

The Tariff Order regulates the pricing of tariffed services and excluded services to be provided by TPA (now GasNet) and other persons in the Victorian gas industry. Section 9.2 of the Tariff Order places limits on the Commission (and other relevant regulators) in its determination of the tariffs to apply in the subsequent (that is, second) access arrangement period. Clause 9.2(a) of the Tariff Order states that the following fixed principles apply to incentives:

> (1) Adopt incentive based regulation using a CPI-X approach (not rate of return regulation);
>
> (4) Ensure a fair sharing of benefits between the service provider and users of the benefits achieved through efficiency gains if, in the initial regulatory period, the service provider has achieved efficiencies greater than the value implied by the X factor used in the initial regulatory period. In ensuring a fair sharing of benefits, the service provider may have regard to the following matters without limitation:

(A) The need to offer the service provider a continuous incentive to improve efficiencies both in operational matters and in capital investment;

(B) The desirability of rewarding the service provider efficiency gains, especially where those gains arise from management initiatives to increase efficiency;

(7) the Regulator may choose to share the benefits achieved in the first regulatory period both in the subsequent regulatory period and in subsequent access arrangement periods; and

(8) the Regulator may issue statements of regulatory intent relating to the proposed benefit sharing mechanism.

10.1.3 GasNet proposal

GasNet states that there is a limited role for benefit sharing in both the first and subsequent periods for capital expenditure. This is because, unlike gas distribution businesses, GasNet's capital expenditure tends to be lumpy, well defined and confined to a small number of projects. Consequently, GasNet proposes no carryover in the second period for any capital expenditure efficiencies achieved in the first access arrangement period.

For operating costs, GasNet proposes a carryover of benefits achieved in the first access arrangement period into the second access arrangement period. Under the approach put forward by GasNet, operating cost efficiency savings are calculated as the difference between the original forecast of operating costs for the year 2002 and the average of approved operating cost forecasts (in real dollars) for the second access arrangement period. For the purposes of making this calculation, GasNet adjust the operating cost forecasts for the second period to exclude regulatory review costs, the increase in insurance costs and Esso litigation costs, and adjust the forecast for the last year of the first period to reflect additional workload, inflation, and an adjustment for regulatory expenses. The total efficiency benefit using this methodology is calculated to be $2.22 million. GasNet then determine the net present value of these savings in perpetuity, and a proportion of this value (20 per cent) is distributed as additional allowed revenue across the second access arrangement period. This results in the distribution of a total of $5.4 million (in 2003 dollars) across the second period using the tariff levelisation procedure. [334]

In relation to operating cost efficiency benefits achieved in the second access arrangement period, GasNet proposes the adoption of the same framework put forward for first period operating cost efficiency gains. Operating cost efficiencies achieved in the second access arrangement period are calculated as the difference between forecast operating costs approved for the last year of the second access arrangement period and average operating costs approved for the third access arrangement period. The NPV of calculated efficiency gains distributed in perpetuity is multiplied by S, a specified sharing ratio. GasNet does not specify a value for S, but states that actual conditions faced by GasNet, including the ageing of the pipeline system and the changes in workload, should be taken into account when determining the value of S in the future.[335]

[334] GasNet submission, 27 March 2002, pp. 99-100.

[335] GasNet access arrangement, 27 March 2002, p. 10-11.

10.1.4 Submissions

BHP Billiton agrees that there should be an incentive system in place to encourage an improvement in the performance of the regulated assets. However, it contends that efficiency gains achieved by GasNet rightly belong to the users, and thus the greater share of the benefits achieved by the company should accrue to the user. BHP Billiton states that it is inappropriate for the incentive mechanism put forward by GasNet to reward asset owners for the upside, but not subject them to any of the risk of under-runs in performance. BHP Billiton states that the mechanism proposed by GasNet for future periods needs to be debated more fully with more information provided by GasNet.[336]

With regard to efficiencies achieved in the first period, BHP Billiton suggests that the approach put forward by GasNet is highly questionable and completely avoids the whole purpose of incentive regulation. BHP Billiton asserts that GasNet should provide information as to the actual savings made in the current period, calculated as the difference between the actual recorded costs and the amount for operations and maintenance costs that were allowed in the current period.[337] The approach to incentives adopted by the ESC for the first period is strong supported by BHP Billiton.[338]

Amcor and PaperlinX note that the mechanism put forward by GasNet allows the company to take all of the benefits from efficiency gains while all losses are passed onto users. It is suggested that GasNet should be provided with incentives for out-performance, but that only a proportion of gains should be retained, and losses should be shared. Amcor and PaperlinX also support the approach adopted by the ESC.[339]

TXU submit that GasNet's proposal to calculate efficiency gains against forecast expenditure may result in GasNet not sharing gains with users, and that the adjustment of forecast costs for additional workload may not be appropriate. TXU argue that the approach adopted by the Commission should be consistent with the ESC's approach to efficiency gains.[340]

Similarly, the Energy Users Association of Australia submit that the ESC's approach to efficiencies put forward in the decision of electricity distribution pricing offers a reasonable approach to the share of efficiencies going to users. The EUAA also states that efficiency gains resulting from capital expenditure and staff time appropriately belong to users:

> Because the users ultimately take all of the direct risk between cause and effect, there can be no doubt that the greater part of the benefits arising from good performance of the asset owner should accrue to the user. Where the asset owner takes the direct risk for improvements, then the asset owner should reap the benefits of such actions. GasNet's submission appears to seek

336 BHP Billiton submission, 21 June 2002, pp. 21-22.

337 ibid., pp. 41-42.

338 ibid., p. 21.

339 Amcor and PaperlinX submission, 24 June 2002, p. 19.

340 TXU submission, 31 May 2002, p. 36.

funding for staff and capex to enhance the performance of the GasNet assets. As users will provide this funding, the larger part of the benefits should accrue to users.[341]

10.1.5 Commission's considerations

Benefit sharing for subsequent periods

As noted, the proposal put forward by GasNet for capital expenditure does not allow for the carryover of efficiency gains (losses) in the subsequent access arrangement period. This approach, however, does provide some incentives for efficiencies. This is because capital expenditure forecasts are incorporated in the revenue model at the start of an access arrangement period, resulting in GasNet effectively keeping for the remainder of the access arrangement period the finance cost savings of any capital expenditure efficiencies achieved. A mechanism that does not allow a carryover of efficiency gains (losses) is known as a P_0 approach.

On the basis of the information available the Commission considers that GasNet's proposal is appropriate for capital expenditure savings (losses) achieved. This is because the methodology provides some incentive for efficiency savings, while at the same time limits the incentive for GasNet to overforecast capital expenditure at the start of an access arrangement period. GasNet faces an incentive under any benefit sharing mechanism to overforecast capital expenditure, given that it keeps the finance cost savings of any overforecast achieved. This behaviour is difficult to observe given its lumpy, inconsistent nature. However, the Commission considers that a P_0 mechanism should limit this incentive while at the same time encourage some productivity improvements.[342]

With regard to operations and maintenance expenditure, the Commission considers that the proposal put forward by GasNet does not represent an appropriate benefit sharing scheme. The Commission is of the view that the mechanism proposed by GasNet is inadequate on a number of grounds:

- it does not provide a continuous incentive for efficiency improvements. Specifically, there may be an incentive under this regime for GasNet to defer the implementation of operating cost efficiencies achievable at the end of the current period until the start of the subsequent access arrangement period, or even increase expenditure at the end of the current period in order to substantiate higher forecasts in the subsequent period;
- it does not encourage the revelation of underlying efficient costs;
- it does not consider temporary efficiency gains/losses that may have been achieved by GasNet within the period. The Commission is of the view that benefits and losses should be shared with users regardless of whether they are temporary or permanent, and that it is difficult to distinguish between what constitutes temporary and permanent efficiency savings (losses);

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[341] EUAA submission, 11 July 2002, p. 11.

[342] The Commission considers that it may be worthwhile undertaking further research on benefit sharing mechanisms for capital expenditure. At a conference held by IPART on 5 July 2002, it was noted by Greg Houston from National Economic Research Associates (NERA) that the issue of how to deal with capital expenditure efficiencies remains a difficult question.

- the mechanism proposed by GasNet is likely to understate the share of benefits it receives. This is because it excludes the benefits (losses) achieved within the initial period, which are generally included in efficiency calculations;
- the model is asymmetric in that only efficiency gains, not losses, can be carried forward. This characteristic is problematic as it provides an incentive for inefficient behaviour; and
- when calculating the NPV, the model inappropriately assumes that the life of the asset is infinite.

The Commission considers that the approach known as the rolling carryover mechanism provides a more appropriate incentive structure. This mechanism has been proposed by the ESC for the Victorian electricity and gas distribution businesses. The following discussion outlines the rolling carryover mechanism and the Commission's specific application of this benefit sharing scheme.

Operation of the rolling carryover mechanism

Under the rolling carryover mechanism, each year's efficiency gain (loss) is calculated by taking the actual reduction (increase) in expenditure minus the reduction (increase) in expenditure anticipated for that year at the start of the previous access arrangement period.[343] This unanticipated efficiency gain (loss) is retained by the service provider for the remainder of the access arrangement period. Further, the regulated tariff is adjusted in the subsequent access arrangement period so that the service provider carries the efficiency gains (losses) for a pre-determined number of years, regardless of when they are achieved.

To illustrate, consider a service provider that has operating cost forecasts and actuals as denoted in Table 10.1. In this example there are no efficiencies achieved in year one. In year two the service provider achieved a total of $10 of efficiencies, calculated through subtracting the forecast reduction in costs between year one and year two ($0) from the actual reduction in costs that occurred between these years ($10). Calculated the same way, the firm achieved an additional $5 of unanticipated gains between year two and year three, and again between year three and four it achieved $5 of unanticipated gains. In this example, the regulator determines that the cost forecasts for the second period to be $80 dollars per year.

Under the rolling carryover mechanism proposed by the Commission, unanticipated gains of $10 in year two and $5 in years three and four are kept in the year that they are implemented and for the remainder of that access arrangement period. Revenues in the subsequent period are then adjusted so that calculated efficiency gains (losses) are maintained for a total of five years in addition to the year that they are introduced. In this example, the regulator adds $20 in year six and seven, $10 in year eight and $5 in year nine to the revenues otherwise calculated for those years. This brings the total retention of operating cost efficiencies to six years irrespective of when they are

343 ORG, *2003 Review of gas access arrangements: consultation paper no.1 – issues for consultation*, May 2001, p. 96.

achieved.[344] After that time the allowable revenues for operations and maintenance expenditure are reduced to correspond with the forecasts made at the beginning of the subsequent regulatory period.

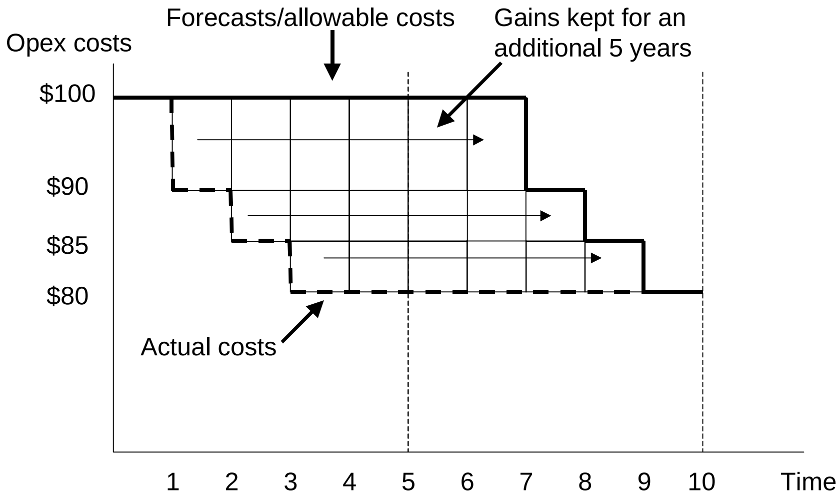
This example of the rolling carryover mechanism is illustrated in the following table and figure.

Table 10.1: Example of the rolling carryover mechanism

Year	1	2	3	4	5	6	7	8	9	10
Forecast	100	100	100	100	100	80	80	80	80	80
Actuals	100	90	85	80	80					
Year to year efficiency	0	10	5	5	0					
Yr 2 gains kept in the period 1			10	10	10					
Yr 2 adjustments made in period 2						10	10			
Yr 3 gains kept in period 1				5	5					
Yr 3 adjustments made in period 2						5	5	5		
Yr 4 gains kept in period 1					5					
Yr 4 adjustments made in period 2						5	5	5	5	0
Total benefit retained by firm	0	10	15	20	20	20	20	10	5	0
Total O&M revenue	100	100	100	100	100	100	100	90	85	80

344 The service provider retains benefits for six years regardless of what part of the year efficiency projects are initially implemented. For example, if a firm has cost forecasts of $100 per year and implements $20 of gains in the fourth quarter of year two, then measured costs in that year would average out to $95. Under the carryover the firm retains this $5 for an additional five years. In year three, assuming no additional productivity improvements have been made, actual costs measured would equal $80, implying an efficiency improvement between years two and three of $15. The firm then carries this $15 for an additional five years. Thus in total the firm carries the $20 achieved for an equivalent of six years - $15 for six years and $5 for six years.

Figure 10.1: Illustration of the rolling carryover mechanism



Benefits of the rolling carryover mechanism

Many of the problems associated with the GasNet approach to benefit sharing are overcome through the implementation of the rolling carryover mechanism. Firstly, the rolling carryover mechanism provides a continuous incentive for efficiency gains throughout an access arrangement period. Given that efficiency gains achieved in one year are kept for the same length of time as gains obtained in any other year, it will always be in the interests of a profit-maximising service provider to introduce efficiency projects as soon as possible because of the time value of money. This property of the rolling carryover mechanism is recognised by GasNet, which notes that the ESC model 'has the theoretical advantage of providing a consistent incentive to improve in each year of an access arrangement.'[345]

Another advantage of the rolling carryover mechanism is that there is no need to distinguish between temporary and permanent efficiencies because all gains as well as losses achieved by the service provider are shared with users.

A third advantage of the rolling carryover is that there is greater transparency over the setting of the distribution of benefits. Under this mechanism, the number of years that the service provider can retain operating cost efficiencies, and thus the sharing of benefits, can be set on an ex ante basis. This compares to other mechanisms, including the proposal put forward by GasNet, where information pertaining to the actual distribution of benefits is only available ex post.

A fourth benefit is that by providing an ongoing incentive for least cost operation, it encourages the firm to reveal its underlying costs.[346] This important characteristic of the rolling carryover model is discussed in detail later in this chapter.

[345] GasNet submission, 27 March 2002, p. 100.

[346] ORG, May 2001, p. 93.

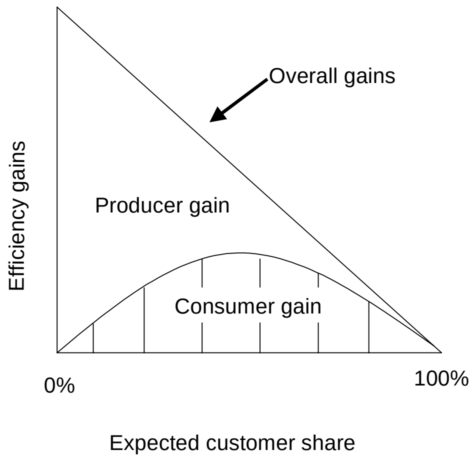
Distribution of benefits

As noted above, under the rolling carry over incentive mechanism the distribution of efficiency benefits between the service provider and users can be determined on an ex ante basis.

It is suggested that there is a trade-off between the distribution of unanticipated gains to the service provider and economic efficiency.[347] It is argued that the productivity of the service provider will be higher when the firm's share of the benefits are greater. This is because the firm is more likely to implement risky efficiency generating projects when the expected payoff to the firm of introducing these projects is higher.

The Commission is not aware of any empirical studies undertaken to assess the optimal distribution of benefits, although a number of theoretical arguments have been put forward. An analysis undertaken by NERA suggests that a 50 per cent sharing may maximise user gains. This conclusion is based on the assumption that there is a proportional relationship between efficiency gains and user share. That is, if the firm is able to keep 50 per cent of any benefits achieved, then half of all potential efficiencies will actually be implemented.[348] The following figure illustrates the NERA hypothesis.

Figure 10.2: The trade off between efficiency and the distribution of gains



Others argue that an equal sharing of benefits between the firm and consumers may not be the most appropriate distribution. In an article noted by the ESC, UK-based consultants OXERA purport that in the majority of cases the optimal share remains in the range of 40-60 per cent for the firm, depending on the form of the relationship assumed between incentives and gains.[349] The ESC suggests that a sharing mechanism that gives the firm approximately 30 percent of unanticipated gains will provide sufficient efficiency incentives for productivity improvements.

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[347] NERA, *Incentives and commitment in RPI-X regulation,* October 1997; S King, 'Principles of price cap regulation', *Infrastructure regulation and market reform, principles and practice: selected papers prepared for the utility regulation training program,* November 1997; ORG, *Electricity distribution price determination 2001-2005 volume 1: statement of purpose and reasons,* September 2000.

[348] NERA, 1997. p. 11.

[349] ORG, September 2000, p. 92.

This argument for a 30 per cent sharing made by the ESC is based on the notion that the relationship between productivity gains and consumer distribution is concave. That is, as the share of gains (losses) retained by the firm increases, productivity improvements are proportionately higher initially, but fall off quickly. It is argued by the ESC that this represents an appropriate assumption as the idea that efficiency gains fall with further incentives is consistent with diminishing returns which underpins much of economic theory.[350]

The Commission concurs with the ESC's assessment. It considers that a distribution of operating cost efficiency savings of approximately 30 per cent to the service provider is appropriate as it should provide sufficient incentives to the firm to implement productivity improvements. A sharing of approximately 30 per cent is achieved through allowing a service provider to maintain unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years.[351]

Equal treatment of gains and losses

The Commission is of the view that unanticipated losses (overruns) should be treated the same as gains in the rolling carryover mechanism. Only then will the mechanism function smoothly. To illustrate, consider a firm that faces constant costs over the length of a regulatory period that corresponds with forecast costs. Under a mechanism that does not require the retention of losses, the service provider has an incentive to claim a gain in one year, and to shift expenses to the following year and claim a loss. Through this strategy, the firm is allowed to maintain the reported benefit for six years, but only has to bear the reported loss during the year that it occurs. An example of this gaming opportunity is illustrated in the following table:

Table 10.2: Example of an asymmetric rolling carryover mechanism

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Forecast	100	100	100	100	100				
Reported	80	120	100	100	100				
Year to year efficiency	20	-40	20	0	0				
Yr 1 efficiency carryover		20	20	20	20	20	0		
Yr 2 efficiency carryover			0	0	0	0	0		
Yr 3 efficiency carryover				20	20	20	20	20	0
Total efficiencies retained by firm	20	-20	40	40	40	40	20	20	0
Actual change in cash flows	20	-20	0	0	0	40	20	20	0

The example illustrates that the service provider can earn an additional cash flow of $80 in nominal terms by adjusting the timing of costs when asymmetry exists in the

[350] ibid., p. 93.

[351] This calculation is based on a real vanilla WACC of 6.4 per cent.

rolling carryover mechanism. Such behaviour is clearly not efficient – consumers would have to carry these additional costs through unnecessary higher prices.

The Commission therefore considers that the incentive mechanism operating for GasNet should incorporate both losses and gains. A symmetrical approach should remove any incentive for GasNet to game the Commission through expenditure adjustments. Under the proposed approach, GasNet is only subject to 30 per cent of any losses incurred through the course of an access arrangement period.

Uncontrollable gains and losses

Uncontrollable gains (losses) are cost savings (losses) that result from factors outside of the firm's control, such as the weather or general economic conditions. Incentive mechanisms have no impact on these outcomes, thus in theory the firm should not be rewarded or penalised for uncontrollable events.

However, in practice the separation of uncontrollable gains (losses) from controllable gains (losses) is often very difficult. In order to distinguish between these costs, the Commission would have to undertake detailed analysis of company expenditures at each scheduled review of the access arrangement. Such analysis would be time consuming for all parties involved, and may not generate appropriate conclusions given the information asymmetry between the Commission and a service provider. Moreover, even if it is established that specific costs were the outcome of events outside of the firm's control, the service provider may have been able to mitigate the consequences. For example, a firm can protect itself from input price increases through the use of financial instruments such as futures contracts.

Given these difficulties, the Commission considers it is more appropriate and practical that no distinction is made between controllable and uncontrollable gains (losses) in applying the rolling carryover mechanism.

Adjustment for changes in volumes

The Commission considers that the calculation of efficiency gains (losses) should not involve adjustments for differences between forecast and actual volume growth within the access arrangement period. This is because the variable or marginal cost associated with an increase in volumes is likely to be negligible for a transmission pipeline network. Also, an increase in volumes is a commercial decision. If a service provider considers ex ante that the revenue associated with an increase in volumes exceeds the costs associated with additional volume growth, then a profit maximising service provider will allow for this volume growth and will be rewarded for any resulting profits. If the service provider was compensated for any additional costs by users through an adjustment to the calculation of efficiency gains (losses), then it would face distorted 'prices' and may therefore make inappropriate decisions that violate allocative efficiency principles.

While the Commission is of the view that volume growth should not be adjusted for, it would be appropriate to adjust the efficiency mechanism ex post to take into account additional costs associated with capital expenditure deemed prudent and included in the capital base. The service provider could submit relevant information at the time of the next scheduled review, and if deemed appropriate, an adjustment to operations and maintenance expenditure in the previous period could be made for the purposes of calculating the efficiency carryover in the subsequent period.

Treatment of final year expenditure

At the time that the Commission determines reference tariffs there will be no information available on a service provider's actual expenditures for the last year of the access arrangement period. In order to overcome this difficulty, the ESC have suggested an approach whereby expenditure in the last year of the access arrangement period is assumed to be the same as expenditures in second last year, less the efficiency gains (losses) assumed in the original forecasts.[352]

If the estimates for expenditure in the final year of the access arrangement period are used to determine operations and maintenance cost forecasts in the subsequent period, then this treatment of final year costs should have negligible impact on revenues established for the service provider. If the firm achieves an efficiency gain in the last year of the access arrangement period, then there would be no carryover of that unanticipated gain. However, the benchmark determined for the next access arrangement period would be higher by an amount equal to the gain, resulting in the service provider receiving revenues as if the efficiency had been recognised through the carryover mechanism.[353]

Trend factor

The ESC has proposed a mechanism where estimated actuals in 2002[354] are used as a foundation for establishing allowed forecasts of operations and maintenance expenditure in 2003-2007. Specifically, this approach involves the assessment of the required step in expenditure levels between estimated actuals in 2002 and 2003, and then the application of a percentage trend factor expected over the next period to determine forecast operations and maintenance costs. The ESC proposes that the trend factor reflects assumptions regarding annual productivity gains, cost of inputs and the impact of demand growth, while the step factor incorporates movements in a range of different cost items, such as the impact of full retail contestability, licence fees and insurance premiums.[355]

The Commission agrees in principle with this approach put forward by the ESC. However, the Commission does not regard this mechanism appropriate for GasNet's forthcoming access arrangement period. This is because GasNet would not have been aware during most of the first access arrangement period of the likelihood of the rolling carryover mechanism model being introduced at this time and so would not be expected to have responded to its incentives in the first access arrangement period.

GasNet may have expected a more traditional benefit sharing approach such as a glide path or a P_0 mechanism to be adopted at this review. Accordingly, its actions during the initial access arrangement period may reflect these expectations. As a result, the

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352 ORG, May 2001, p. 100.

353 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 121.

354 Estimated using the methodology noted above.

355 ESC, July 2002, pp. 49-51.

environment would not have provided an incentive for least-cost production at all times, and actual operations and maintenance costs achieved by GasNet in the first period may not be cost reflective.

While the trend and step methodology is not appropriate for the forthcoming access arrangement period, the Commission considers that a trend approach based on operations and maintenance cost actuals achieved in 2006 is reasonable for the third access arrangement period (expected to be from 2008 to 2012). The adoption of the rolling carryover mechanism for efficiency gains (losses) achieved in the 2003-2007 period should ensure the achievement of efficient operations and maintenance costs in that period, which can be reasonably used as the basis of a step and trend factor adjustment for operations and maintenance cost forecasts in the following period. Details relating to the calculation of the trend and step factors will need to be developed at GasNet's next scheduled review. GasNet may elect to include these details in this revised access arrangement.

Conclusion

To summarise, the Commission regards the approach put forward by GasNet for capital expenditure benefit sharing is not unreasonable, but that the mechanism proposed for the calculation of the operations and maintenance costs allowance in the third access arrangement period is not appropriate. The Commission proposes the implementation of the rolling carryover mechanism for operations and maintenance costs. The specific mechanism it proposes allows GasNet to retain efficiency gains (losses) for five years in addition to the year that they are achieved, treats gains and losses equally and does not distinguish between controllable and uncontrollable gains (losses). The Commission also proposes that actual costs achieved in 2006 be used as the basis for expenditure benchmarks in the third access arrangement period.

The Commission considers that the benefit sharing carry forward amount should be calculated and distributed in real dollar terms.

Following the discussion above, the Commission proposes an amendment to GasNet's revised access arrangement with the purpose of establishing an appropriate incentive mechanism.

Proposed amendment 30

GasNet must amend clause 7.2 of its revised access arrangement so that the benefit sharing allowance calculated for the third access arrangement period is based on the rolling carryover mechanism. The amended mechanism must:

- allow GasNet to keep unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years;
- allow for the carryover of both unanticipated efficiency gains and losses;
- make no distinction between controllable and uncontrollable gains (losses);
- determine operations and maintenance expenditure achieved by GasNet in 2007 by taking 2006 actuals and adjusting these by the change in expenditure forecast to occur between 2006 and 2007;
- not allow an adjustment for volume growth, except for operations and maintenance costs associated with capital expenditure deemed prudent and rolled into the asset base; and
- ensure that all amounts are expressed in 2008 dollars.

Benefit sharing for the first period

As noted earlier, GasNet proposes a limited role for benefit sharing in capital expenditure in the first and subsequent access arrangement periods. The approach suggested by GasNet corresponds with a P_0 mechanism, whereby all savings (losses) are transferred to users at the start of a new access arrangement period. For the reasons given above, the Commission is satisfied with the application of this approach to capital expenditure savings (losses) achieved in the first access arrangement period as well as the second.

Sharing mechanism

For operations and maintenance expenditure, the previous discussion outlined the merits of the rolling carryover mechanism. The Commission, however, considers that the rolling carryover mechanism is not appropriate for the first period. This is because GasNet was not aware of the rolling carryover incentive model and could therefore not respond to it in the first access arrangement period. Also, the approach adopted now cannot influence past behaviour.[356]

The Commission has determined that the approach put forward by GasNet for the first period is not reasonable. In principle, the Commission does not oppose the comparison of forecasts to determine the efficiency gain (loss) achieved by the service provider. However, it is concerned with the distribution of the calculated allowance proposed by GasNet. The GasNet proposal is problematic as it assumes that the asset life is infinite in the calculation of net present values, is likely to understate the share of benefits for GasNet, and may generate an unfair sharing of benefits with users if GasNet benefits from temporary efficiencies not reflected in the measure.

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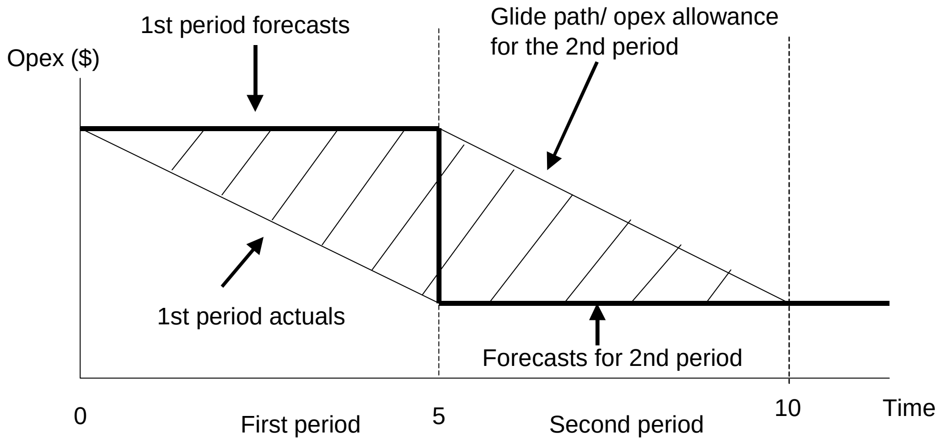
[356] ORG, *Draft Decision: 2001 electricity distribution price review,* May 2000.

The Commission considers that a glide path mechanism would be more appropriate for operations and maintenance expenditure gains achieved by GasNet in the first access arrangement period. The glide path mechanism was highlighted by the Commission in the DRP and was adopted by the ESC in 2000 for first period efficiency gains achieved by electricity distribution companies.[357]

Under a glide path, operations and maintenance expenditure forecasts are initially calculated for the subsequent period based on the regulator's determination of efficient costs. These target revenues are then adjusted to allow for any efficiency gains obtained by the firm over the previous period. The benefits (losses) achieved by the company are shared with users in the subsequent period by the gradual reduction of gains (losses) irrespective of their source.[358] In the DRP, the Commission stated that it would be appropriate to implement a glide path for one regulatory period beyond the period in which the efficiency gains accrued, and that a straight-line phase out of efficiency gains would be reasonable for simplicity.[359] Under this approach, any efficiency gains (losses) are incrementally reduced (increased) so that at the end of the period the benefit (loss) has moved to consumers entirely. The following figure illustrates a glide path mechanism as discussed in the DRP.

Figure 10.3: Glide path benefit sharing mechanism



In the above figure, the shaded area in the first period represents the difference between actual and forecast operations costs in that period, while the shaded area in the second period denotes the benefit accrued by the service provider from the glide path adjustment mechanism. The total shaded area is representative of the net economic profit retained by the service provider.

Measuring efficiencies

The DRP provides little guidance as to the measurement of efficiency gains for the purposes of a glide path carryover, and there seems to be little discussion of this issue in the literature on incentives. As noted previously, the ESC implemented a glide path mechanism for efficiencies achieved in the first period for Victorian electricity

[357] ORG, September 2000, p. 98.

[358] ACCC, May 1999, p. 90.

[359] ibid., p. 90.

distributors. The ESC measured efficiency gains as the difference between actual and forecast operations and maintenance costs in 1999 (which was the fourth year in the regulatory period in question). The Commission considers that this measurement approach is not appropriate. One reason for not adopting this approach is that year four actuals may not be reflective of actual expenditure undertaken in the fifth year of the first period, and unlike the proposed rolling carryover mechanism, there is no adjustment mechanism in place that addresses changes between year four and five expenditures. It is considered imperative that efficiency gains are measured taking year five actuals into account as year five actuals will provide a better indication of permanent efficiency gains. In addition, the use of year four actuals to calculate efficiencies is only valid if the operations costs achieved through the period followed a relatively straight line from forecasts in year one to those achieved in year five. As noted in section 6.1.2 of this Draft Decision and in Figure 10.4 below, GasNet achieved significant temporary gains in the first three years of its first period which consumers would not share under the ESC approach to measuring efficiencies for the glide path.

A second methodology for measuring efficiencies for a glide path is to use the difference between forecasts for the final year of the current period with forecasts for the subsequent period, provided that they are reasonable.[360] This approach overcomes the fifth year information problem associated with the ESC electricity glide path approach, and corresponds with the usual interpretation of a glide path as a gradual movement from the old to new revenue allowance for operations and maintenance costs.

This method requires two pieces of information: cost forecasts for 2002 and an average of cost forecasts for the forthcoming period.

If this approach is applied to GasNet the final year forecasts can be obtained from the 1998 tariff model which forecasts operations and maintenance costs of $18.75 million for 2002 (nominal dollars).[361] The Commission considers that it is appropriate to adjust this figure to take into account additional costs associated with new capital expenditure undertaken during the access arrangement period, such as the Interconnect and the Southwest Pipeline, and regulatory expenses budgeted but not levied in the first period. This allows the efficiency carryover calculated through an assessment of comparable forecasts. GasNet has stated that this total figure is $18.9 million (in 2003 dollars). This adjustment appears reasonable.[362]

With regard to operations cost forecasts for the following period, the Commission outlined what it considers prudent in section 6.1 above. The following table presents these forecasts for 2003-2007 in both nominal and in 2003 dollar terms.[363] The average

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360 This approach to measuring the efficiency achieved in the first period resembles that put forward by GasNet. However, this proposal differs considerably as the Commission's mechanism employs different forecasts to determine the relevant efficiency measure.

361 TPA access arrangement information, 30 November 1998, p. 8.

362 GasNet submission, 27 March 2002, p. 99.

363 An inflation rate of 2.5 per cent is used for this purpose. These figures may change should the proportioning of exceptional costs noted in section 6.1.4 of this Draft Decision effect total operations and maintenance costs.

of operations and maintenance expenditure forecasts proposed by the Commission for 2003-2007 calculated from these figures is $19.20 million in 2003 dollar terms.[364]

Table 10.3: Forecast operations and maintenance costs, 2003-2007

	2003	2004	2005	2006	2007
Nominal dollars	18.2	19.9	19.7	21.4	21.8
Real dollars (2003)	18.2	19.41	18.75	19.87	19.75

Source: ACCC analysis.

Subtracting the average of second period forecasts from adjusted year five forecasts from the first access arrangement period gives an efficiency loss over the first period of approximately $300 000 (2003 dollars terms). This would require GasNet to be subject to a negative glide path adjustment in the second period. With a straight line glide path that gives GasNet 100 per cent of efficiency gains (losses) in 2003, 80 per cent of gains in 2004 and so forth, the business would be subject to the revenue adjustments in the second access arrangement period as indicated in Table 10.4.

Table 10.4: Second period glide path carryover

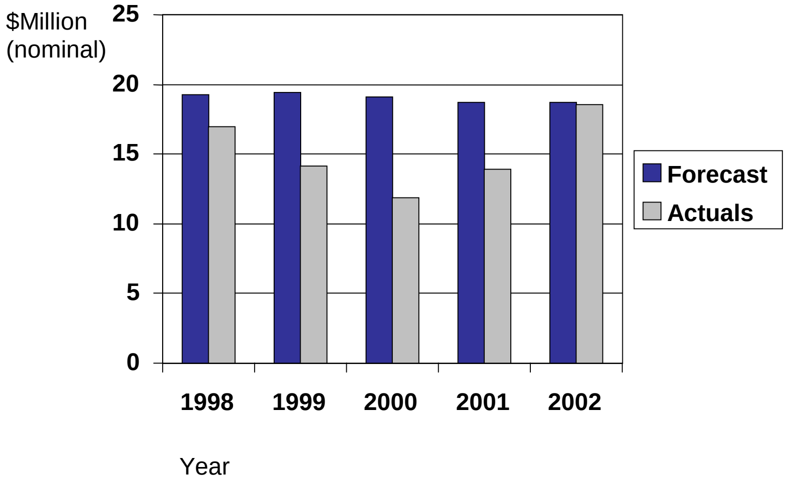
	2003 dollars				
	2003	2004	2005	2006	2007
Calculated efficiency carryover	-300 000	-240 000	-180 000	-120 000	-60 000

Source: ACCC analysis.

A third approach to measuring efficiencies is to assess the unanticipated gains (losses) obtained by GasNet in the first period. Aggregate operations and maintenance costs achieved by GasNet in 1998-2002 were noted in section 6.1.2 of this Draft Decision. These costs can be compared against forecasts for the first access arrangement period to determine the benefit accrued to GasNet in the first period. A comparison of these costs is presented in Figure 10.4 below.

[364] It is considered appropriate to calculate efficiency gains (losses) in real terms. This is because the objective of an efficiency mechanism is to reward the service provider for actual productivity/efficiency improvements (impairments) rather than just nominal improvements.

Figure 10.4: Actual and forecast operations and maintenance costs, 1998 to 2002



This comparison, however, must be interpreted carefully. As noted, the figures forecast at the start of the first access arrangement period do not include an allowance for operations and maintenance costs associated with the Iona and Springhurst compressors and the Interconnect and Southwest pipelines (which means efficiencies achieved are understated), and include a provision for regulatory costs forecast but not paid for by GasNet pipelines (which means efficiencies achieved are overstated).

As the figure above illustrates, actual operations and maintenance expenditure achieved by GasNet for the period 1998-2001 was substantially less than what was originally forecast. However, by the end of the period actual expenditure is expected to approximately equal that forecast, indicating that the efficiency gains in the first half of the period will have been lost by the end of the period. As noted above, the forecast costs for the second access arrangement period are higher than the end of the first period confirming that the efficiency gains in the first period were temporary. As there are no ongoing efficiency gains, there is no reason to add an amount for GasNet to the benchmark revenues.

It should be noted, however, that GasNet has gained from the temporary efficiencies achieved. It could be argued that some of these gains should be shared with users. This would require an amount to be deducted from the benchmark revenues (that is, a negative glide path).

Conclusion

Following the above discussion, the Commission has concluded that the glide path approach to sharing efficiency gains between GasNet and users is appropriate for first period gains even though the rolling carryover approach is the appropriate approach for future access arrangement periods.

As discussed above, a number of reasonable approaches to the calculation of efficiencies achieved in the first period indicate that there are no permanent efficiency gains for users and GasNet to share. In fact there are arguments for deducting an amount from the benchmark revenues, for efficiency losses and/or to share some of the temporary gains with users. However, on balance, the Commission considers that because of the uncertainty relating to the benefit sharing mechanism applying to GasNet at the start of the initial access arrangement period, and the lack of discussion on the treatment of losses, it is unreasonable to deduct revenue from GasNet in the second period for efficiency losses or temporary gains in the first period. Accordingly, the Commission proposes an efficiency carryover of zero in the second period.

Proposed amendment 31

GasNet must amend section 3.5 of its revised access arrangement information to remove any benefit sharing allowance associated with the first access arrangement period.

10.2 KPIs

10.2.1 Code requirements

Category 6 of Attachment A to the Code requires a service provider's access arrangement information to include information regarding Key Performance Indicators (KPIs). Items specified as examples are industry KPIs used by the service provider to justify reasonably incurred costs and a service provider's KPIs for each pricing zone, service or category of asset.

10.2.2 Current access arrangement provisions

GasNet's access arrangement information currently includes four tables containing KPIs:

- operational costs for TPA (now GasNet), AlintaGas, the Pipeline Authority (now EAPL) and PASA (now Epic SA) in terms of cost, cost per 1 000 km and cents per gigajoule;
- TPA's forecast operations and maintenance costs from 1998 to 2002 in terms of cost, cost per 1 000 km and cents per gigajoule;
- TPA's zonal forecast from 1998 to 2002 in terms of operations and maintenance costs, quantity of throughput and cents per gigajoule; and
- cents/gigajoule for TPA (from Longford to Pakenham), EAPL (Moomba to Wilton), Epic (Moomba to Adelaide and Ballera to Wallumbilla) and Alinta (Dampier to Perth).

10.2.3 GasNet proposal

GasNet has provided KPIs based on data relating to seven Australian pipeline companies, using information available from access arrangement approval processes.[365] GasNet states that the data represent the forecast operating costs in 2003, net of

[365] GasNet access arrangement information, 27 March 2002, pp. 31-36.

working capital and compressor fuel costs. Operating costs comprise General and Administrative (G&A) and O&M costs. GasNet states that maintenance capital expenditure has not been included in the comparison.

GasNet states that normalising factors are needed to make costs comparable and that these consist of various measures of workload in order to attempt to represent the cost drivers of a particular company. GasNet states that its forecast costs for 2003 have been adjusted to make the KPIs more comparable by adding an allowance for gas control to GasNet's costs (a function that other companies perform but which is performed by VENCorp on the PTS) and by excluding the increment in insurance cost experienced by GasNet.

Table 10.5 below provides the following comparisons:

- operating costs per GJ of gas delivered;
- operating costs as a percentage of capital investment;
- O&M costs per metre of pipeline;
- G&A costs per GJ of gas delivered; and
- O&M costs as a percentage of capital investment.

Table 10.5: Australian pipeline KPIs

	Operating costs/ GJ $/GJ	Operating costs/ ORC %	O&M/ metre $/metre	G&A/ GJ $/GJ	O&M/ ORC $
PTS	0.08	2.1	5.09	0.03	1.2
Moomba-Adelaide	0.12	2.4	3.52	na	na
Moomba-Sydney	0.14	1.2	4.38	0.04	0.9
Dampier-Bunbury	0.15	1.8	13.46	0.02	1.5
Parmelia	0.21	2.4	8.45	0.02	2.1
Goldfields	0.42	2.4	5.37	0.13	1.6
Amadeus Basin	0.45	2.1	3.52	0.09	1.7
Central West	0.69	2.6	1.95	0.26	1.6

Source: GasNet access arrangement information, 27 March 2002, pp. 33-35.

In addition, GasNet provided a detailed benchmarking report compiled by Cap Gemini as an annexure to its submission, which it summarised in its access arrangement information. The report is based on GasNet's actual operating results for the year 2000 and also includes historical 1999 and projected year 2001 results. It compares GasNet's performance against a sample of 24 companies from Australia, Canada, USA and South America and against four specific peer group companies. GasNet selected three indicators as being the most representative of the cost efficiency of GasNet: G&A expenses per million cubic meters delivered; pipeline maintenance expenses; and compressor maintenance expenses. GasNet advises that these costs were defined specifically to enable inter-company comparisons and are not consistent with the definitions used for the comparison of Australian pipeline companies referred to earlier.

GasNet summarised findings of the report as follows:

- GasNet's overall G&A expenses per million cubic metres delivered were 55 per cent lower than the peer group average and GasNet's unit costs fell very close to the lowest or best quartile of all participating companies;
- GasNet's pipeline maintenance expenses per kilometre of pipeline system were lower than the peer group average and the all company median; and
- GasNet's compression costs were marginally higher than the median cost for the industry sample.

GasNet noted that the report commented that GasNet has a very low compressor utilisation factor, reflecting its seasonal demand patterns, and that intermittent stop-start operation leads to higher costs compared to other companies. In contrast, some of the other companies in the sample operate long haul systems with very high unit horsepower and high utilisation rates.

Cap Gemini outlined the purpose and limitations of its study as follows:[366]

> This benchmarking is focused on operational efficiency and effectiveness. It is not a tool that can be used for the following:
>
> 1. Setting transportation prices.
> 2. Determining precise levels of efficiency and precise targets for performance.
>
> Benchmarking is an approach to identifying the differences in your operations relative to a sample of other gas transmission companies. It is directional in nature; that is, pointing your company in the directions where it may wish to review operations for potential improvements in overall performance.[367]

10.2.4 Submissions

Amcor and PaperlinX commented on the broadness of the opex cost categories reported by GasNet and the need for benchmarks to be useful and directly comparable.[368] They consider the data provided in relation to operating and marketing are inadequate. Further, they propose that comparisons be based on aggregate data for GasNet and VENCorp which they consider would show that operations and maintenance related charges paid by users of the PTS would be 'well beyond the "reasonable" range' claimed to by GasNet.

BHP Billiton also considers that the costs for GasNet and VENCorp should be aggregated.[369] BHP Billiton further comments that those costs referred to by GasNet as exceptional costs should be included in the comparisons. BHP Billiton estimates that if these adjustments are made that the KPIs for the PTS would be approximately double those shown in Table 10.5 above.[370] BHP Billiton is concerned that inappropriate use of

366 GasNet submission, 27 March 2002, annexure 9.

367 ibid., p. 7.

368 Amcor and PaperlinX submission, 24 June 2002, pp. 21-22.

369 BHP Billiton submission, 21 June 2002, pp. 40-41.

370 One exception is that BHP Billiton's estimate for G&A per GJ of $0.04 is a third higher than GasNet's figure of $0.03.

benchmarking could lead to GasNet being over compensated for efficiency gains and suggests that it be set challenging targets for the second access arrangement period.

In addition, BHP Billiton considers that GasNet's approach of providing KPIs based solely on Australian pipeline systems is inadequate as there are only a relatively few independent gas transmission system service providers in Australia and such comparisons 'will result ultimately in circular prophesies.'[371] BHP Billiton considers that GasNet should be required to identify comparable overseas benchmarks.

EnergyAdvice benchmarked GasNet's current and proposed tariffs (for Tariff D customers) against those for DEI's EGP (from Longford to Horsley Park) and the current tariffs for the EAPL pipeline (from Moomba to Wilton). Table 10.6 below provides Energy Advice's estimates of the tariff for each of the pipelines after adjustment for load factor and distance expressed as dollars per Terajoule per kilometre of pipeline.

Table 10.6: Australian transmission pipeline tariff comparison[a]

Customer	Load factor	GasNet $/TJ/km current	GasNet $/TJ/km proposed	EAPL $/TJ/km current	EGP $/TJ/km published	EGP $/TJ/km July 2003
Metro	90%	$1.11	$1.83	$0.56	$1.19	$0.87
% of current GasNet		100%	166%	51%	108%	78%
Metro	75%	$1.20	$1.90	$0.67	$1.43	$1.04
% of current GasNet		100%	159%	55%	119%	87%
Metro	60%	$1.34	$2.01	$0.82	$1.79	$1.30
% of current GasNet		100%	150%	62%	134%	97%
Echuca	75%	$1.55	$1.49	$0.67	$1.43	$1.04
% of current GasNet		100%	96%	43%	92%	67%
Echuca	60%	$1.78	$1.53	$0.82	$1.79	$1.30
% of current GasNet		100%	86%	46%	101%	73%
Wodonga	75%	$1.39	$2.23	$0.67	$1.43	$1.04
% of current GasNet		100%	160%	48%	103%	75%
Wodonga	60%	$1.61	$2.26	$0.82	$1.79	$1.30
% of current GasNet		100%	140%	51%	111%	81%

Source: EnergyAdvice submission, 30 May 2002, p. 12.
Note: (a) Calculations are based on a customer with an annual volume of 1 PJ with the load factor adjusted by varying the MDQ.

EnergyAdvice concludes that the proposed GasNet charges are the highest of the three transmission pipelines when compared on a dollar per TJ per kilometre basis other than for the Echuca zone for a relatively average load factor.[372] EnergyAdvice comments

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371 BHP Billiton submission, 17 May 2002, pp. 13-14.

372 EnergyAdvice submission, 30 May 2002, p. 12.

that the comparison highlights that the proposed GasNet tariff structure is relatively insensitive to the load factor.

TXU states that it is not convinced of the validity of the reasons given by GasNet for excluding and adjusting costs and considers that the KPIs provided may be misleading.[373] For example, TXU states that 'GasNet does monitor very carefully VENCorp's operation of its compressors' and that 'GasNet should be able to derive benchmarks with compressor fuel in order to provide a basis for determining whether its forecast compressor costs are reasonable'. In addition, TXU states that it does not agree with the exclusion of maintenance capital expenditure, and questions whether this expenditure has been excluded from the comparators. Further, TXU enquires as to the basis and size of adjustment made in respect of VENCorp's functions.

10.2.5 Commission's considerations

The Commission is cognisant of the limitations which need to be taken into account when considering benchmarking studies. These include:

- differing characteristics of pipelines (for example, maturity and average load, length and diameter);
- uncertainties of adjustments (for example, for VENCorp functions); and
- usefulness of specific KPIs.

In particular, the Commission notes that GasNet has not provided data on a key indicator, O&M/TJ/km. The Commission considers that this KPI could materially help interested parties to make an informed assessment of GasNet's performance and assist them to form an opinion as to the compliance of the revised access arrangement with the provisions of the Code. Accordingly, an amendment to GasNet's access arrangement information is proposed.

Proposed amendment 32

GasNet must amend section 6 of its access arrangement information to include operations and maintenance costs/TJ/km data in its comparison of Australian KPIs.

The Commission acknowledges the difficulty noted in submissions of comparing GasNet's performance under a market carriage system with that of other Australian pipelines that operate on a contract carriage basis. GasNet has included $660 000 per year to its own costs in its comparisons in recognition of the gas control functions performed by VENCorp. However, this represents only a small part of the costs of approximately $16 million a year that users bear for VENCorp services, which include a range of other functions such as operating the Victorian gas market.

BHP Billiton estimates that GasNet's costs expressed in its KPIs, if adjusted for VENCorp costs, would be approximately double that indicated by GasNet. On this basis, GasNet's costs would be higher than that of its comparators. These comparisons raise issues in terms of the costs of both service providers, the relative costs of the

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373 TXU submission, 31 May 2002, p. 37.

market carriage and contract carriage capacity systems and the comparability of the pipeline systems themselves. The Commission acknowledges that the PTS is unusual for a transmission system as it has significant network characteristics not shared with other Australian transmission systems. Further, the PTS has a very peaky load but little linepack. Accordingly, it would be expected to face significantly greater gas control costs than other Australian transmission pipelines.

The Commission notes that the Cap Gemini study provided by GasNet was commissioned to identify areas in which GasNet 'may wish to review operations for potential improvements in overall performance'[374] rather than as an adjunct to a tariff review. For this reason, and others (such as that comparator companies have not been identified), the Commission is of the view that it is of limited relevance to the current review process. Nonetheless, the Commission considers that overseas benchmarks are potentially very useful. It notes the dangers expressed by one interested party of Australian regulators becoming caught in a circular comparison of regulated costs.

As a result of the unique factors inherent to the Victorian gas transmission system, the Commission considers that the available KPIs are inconclusive. It has been unable to isolate the influences of the characteristics of the PTS, the market carriage system and that of GasNet itself. The Commission expects that the 2007 review by the Victorian Government of the market arrangements will carefully examine the interaction of these factors. At present it is of the view that GasNet's KPIs are inconclusive.

The Commission prefers not to attempt to 'micro manage' GasNet with regard to its costs. It considers that effective efficiency incentives are more likely to lead to efficient performance. Accordingly, the Commission places considerable priority on the future incentives mechanisms applying to GasNet.

However, clear signals were not available to GasNet and its predecessors during the first access arrangement period. For this reason, the Commission has carefully considered GasNet's proposed benchmark costs for the second access arrangement period and has proposed a number of changes to those forecast by GasNet.

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[374] GasNet submission, 27 March 2002, annexure 9, p. 7.

11. Non tariff elements

11.1 Services policy

Section 2.3.4 of this Draft Decision discussed the interaction of GasNet's and VENCorp's access arrangements with regard to the PTS. This section considers in more detail GasNet's proposals with respect to reference services.

11.1.1 Code requirements

Sections 3.1 and 3.2 of the Code require an access arrangement to include a services policy which must include a description of one or more services that the service provider will make available to users and prospective users. The policy must contain one or more services which are likely to be sought by a significant part of the market, and any service or services that in the relevant regulator's opinion should be included in the services policy.

To the extent that it is practicable and reasonable, a service provider should also make available only those elements of a service required by users and prospective users and apply a separate tariff for each element if this is requested.

11.1.2 Current access arrangement provisions

Clause 5.2.2 of the PTS access arrangement currently states that GasNet's predecessor, TPA will make the tariffed transmission service available to VENCorp as user at the reference tariffs, on the terms and conditions and in accordance with the reference tariff policy described in the access arrangement. Similarly, the WTS access arrangement states that TPA will make tariffed transmission services (the reference services) available to users or prospective users at the reference tariffs, on the terms and conditions, and in accordance with the reference tariff policy described in the access arrangement. Both access arrangements state that the services are likely to be sought by a significant part of the market.

11.1.3 GasNet proposal

GasNet notes in clause 3.1 of its proposed revised access arrangement that it owns the PTS but that VENCorp operates the PTS, VENCorp obtains the availability of the PTS from GasNet and that market participants contract directly with VENCorp in accordance with the MSOR for access to the PTS. GasNet states that it and VENCorp are parties to the SEA, under which GasNet makes the PTS available to VENCorp and provides a range of supporting services to VENCorp; and that VENCorp operates the PTS in accordance with the MSOR and agrees to direct market participants to pay the transmission tariffs directly to GasNet.

GasNet states that under the market carriage capacity management system, users and prospective users of the PTS are offered one reference service (or bundle of services) comprising the transportation of gas through the PTS via the market carriage system under the MSOR. GasNet states that VENCorp, as operator of the PTS under the

MSOR, is responsible for the provision of the reference service. GasNet further states that although it is a service provider under the Code (because service provider is defined to include both the operator and the owner of a pipeline), GasNet does not, under the MSOR regime, provide any aspect of the reference service directly to users. GasNet considers that the current provisions are inappropriate as it considers that 'VENCorp is not a "User" within the meaning of the Code' and it proposes to alter its access arrangement accordingly.[375] GasNet states that the change would have no substantive impact on users shipping gas via the PTS.

GasNet states that, for the purposes of reference tariff calculation, the reference service comprises VENCorp Services (with in the VENCorp access arrangement) and the tariffed transmission service (being the availability of the PTS, which is sourced by VENCorp from GasNet through the SEA). GasNet states that it 'proposes to revise the form of its Services Policy to bring it into line with underlying commercial and regulatory arrangements.'[376]

11.1.4 Submissions

ENERGEX states it finds 'it difficult to reconcile GasNet's application for tariff approval by the ACCC under the National Access Code without a description of [an] actual reference service' and asks the Commission to request GasNet to properly follow the requirements of the Code.[377]

VENCorp disagrees with GasNet's contention that GasNet does not provide services to users on the grounds that VENCorp is a user of GasNet services which VENCorp notes is currently acknowledged in the PTS access arrangement.[378] VENCorp considers that this description should continue 'given that section 10.8 of the Access Code defines a user to include "a person who has a current contract for a Service".' VENCorp provides as an attachment to its submission a legal advice consistent with its position that GasNet's proposal would not comply with the Code as the revised access arrangement would not clearly state the reference service to which the reference tariff would relate or the terms and conditions of supply.[379] Further, VENCorp states:

> In a regulatory sense, it would be an unacceptable outcome if:
>
> - GasNet, which accounts for around 85% (about $A95 million per annum) of the total annual transmission costs for the main Victorian transmission system, had no reference services for these charges defined in the access arrangement which sets out the associate GasNet reference tariffs;
> - GasNet were able, as a result of its services not being specified in its access arrangement, to alter its services such that they were in conflict with the statutory functions of VENCorp as operator of the PTS; or
> - Prospective users on the PTS were precluded from recourse to GasNet via the access dispute processes in the Access Code in regard to services provided by GasNet. This could

375 GasNet submission, 27 March 2002, p. 122.

376 ibid., p. 122.

377 ENERGEX submission, 9 May 2002, p. 1.

378 VENCorp submission, 13 May 2002, p. 5.

379 ibid., p. 5.

> arise if GasNet does not define its reference services and the terms and conditions of access in its access arrangement. [380]

VENCorp submitted that its preference is for the existing allocation to at least continue, such that:

> … each of VENCorp and GasNet should describe the reference services it provides, and the terms and conditions on which it offers those services, in its access arrangement. Preferably GasNet should include in its access arrangement either the entire Service Envelope Agreement, or describe the key obligations from that agreement. Together, the two access arrangements should describe the total services provided to users, and each entity should describe the particular reference services for which it seeks approval of a reference tariff.[381]

The Victorian Department of Natural Resources and Environment (DNRE) also provided as an attachment to its submission a legal advice consistent with its position that the Commission should not approve GasNet's proposal as GasNet provides services to VENCorp within the meaning of the Code.[382]

TXU is also of the view that GasNet should provide a reference service and is obliged to by the provisions of the Code. It states that it is important for users such as TXU to understand the exact services provided by each of the system owner and operator. TXU is concerned that, while the relationship and division of responsibilities between GasNet and VENCorp is currently made clear by their access arrangements, this would not be the case under GasNet's proposal.[383] TXU comments that it must deal regularly with GasNet, for example when paying for services or when seeking a new connection or additional capacity on the system.

TXU considers that VENCorp is a user of GasNet's services, and that VENCorp's ability to deliver the VENCorp reference services is dependent on GasNet providing capacity of its pipelines available for use by VENCorp under various stipulated operating conditions. TXU also suggests that it should be able to enforce an access dispute directly against GasNet but that it could only pursue VENCorp under the proposed model.[384]

Pulse considers it inconsistent for GasNet to assert that it has no reference services while seeking reference tariffs. Pulse considers that GasNet's services are provided to users through the SEA with VENCorp. It states that if GasNet's services are deemed not to be reference services VENCorp will be 'in the invidious position of having to pass through costs negotiated on a commercial basis.'[385] Pulse notes that this would also leave users without direct recourse to GasNet in the event of non-performance. Further, Pulse comments that the contention that only VENCorp uses GasNet's reference services would overlook those 'customers who come directly off the Principal

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380 ibid., p. 4.

381 ibid., p. 4.

382 DNRE submission, 20 May 2002, p.1.

383 TXU submission, 31 May 2002, p. 3.

384 ibid., p. 4.

385 Pulse submission, 16 May 2002, p. 3.

Transmission System.' Pulse contends 'services generated by the infrastructure owned by GasNet should be characterised by reference services and reference tariffs.'[386]

BHP Billiton questioned whether the legal rights of shippers would be affected by GasNet's proposed changes to its access arrangement 'bearing in mind that VENCorp has no liability to shippers for its actions.'[387] Amcor and PaperlinX similarly commented that users might lack effective redress and recommended that users be able to 'bypass VENCorp and seek restitution from GasNet who not only does not have legislative protection, but also has the assets from which restitution can be funded'.[388]

TXU considers, depending on the outcome of the commercial negotiations between GasNet and VENCorp targeted for June 2002, it may be appropriate for the Commission to consider inclusion of LNG storage for system security purposes as a reference service.

11.1.5 Commission's considerations

The Commission has considered the views put by interested parties, including a number of legal advices.

The Commission is concerned that VENCorp's access arrangement as proposed would not reflect the allocation of responsibility between GasNet and VENCorp as it would not acknowledge that VENCorp is the entity that supplies the whole service to retailers. Consequently, an amendment has been proposed to require VENCorp to amend its proposed services policy to clarify that it is VENCorp who provides to users, not only VENCorp Reference Services, but also the transportation of gas through the PTS via the market carriage system under the MSOR.

Differing views have been expressed as to whether GasNet is supplying a service to VENCorp and whether VENCorp is a user in the terms of the Code.

Section 10.8 of the Code provides the following relevant definitions:

> **'Service'** means 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):
>
> (a) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul);
>
> (b) the right to interconnect with the Covered Pipeline; and
>
> (c) services ancillary to the provisions of such services,
>
> but does not include the production, sale or purchasing of Natural Gas.
>
> **'User'** means a person who has a current contract for a Service or an entitlement to a Service as a result of an arbitration.

The Commission has concluded that GasNet is supplying a service (the tariffed transmission service) to VENCorp within the meaning of section 10.8 of the Code. GasNet describes this service as being the availability of the PTS, which it states is

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386 ibid., p. 3.

387 BHP Billiton submission, 17 May 2002, p. 9.

388 Amcor and PaperlinX submission, 24 June 2002, p. 25.

sourced by VENCorp from GasNet through the SEA.[389] The Commission has concluded that VENCorp is a user of this service as it has a current contract (the SEA) with GasNet for this service. Further, as VENCorp is the only user of this service, and it has expressed its desire to be provided with a reference service by GasNet, the Commission has concluded that this service is 'likely to be sought by a significant part of the market' (section 3.2(a)(i) of the Code).

The Commission has also concluded that GasNet should include in its services policy the services that it supplies to VENCorp (that is, making the PTS available to VENCorp in accordance with the SEA and the MSOR). In addition, it notes that clause 3.2 of GasNet's proposed revised access arrangement refers to 'VENCorp Services' whereas this should be to 'VENCorp Reference Services'.

Accordingly, the following amendment is proposed.

Proposed amendment 33

GasNet must amend clause 3 of its revised access arrangement, services policy, to include the services that GasNet supplies to VENCorp (that is, making the PTS available to VENCorp in accordance with the SEA and the MSOR). In addition, the reference 'VENCorp Services' in clause 3.2 must be changed to 'VENCorp Reference Services'.

11.2 Terms and conditions

11.2.1 Code requirements

Section 3.6 of the Code requires an access arrangement to include the terms and conditions on which a service provider will supply each reference service. Based on the regulator's assessment, these terms and conditions must be reasonable.

11.2.2 Current access arrangement provisions

The current provisions of the PTS access arrangement state that the service provider will make the PTS available to VENCorp in accordance with the SEA. The SEA is a contract between the service provider and VENCorp which requires that the 'gas transmission system' (which is described in detail in the SEA) be made available to VENCorp at all times over the term of the agreement. Failure to do so attracts a penalty.[390]

In addition, the SEA requires VENCorp to operate the gas transmission system in accordance with good practice. VENCorp is to provide services to users in accordance with the MSOR and the Gas Transportation Deed. Users are required to pay GasNet directly for transmission charges.

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389 GasNet access arrangement, 27 March 2002, p. 4.

390 The SEA is not part of the current access arrangement for the PTS.

The access arrangement also states that the service provider is to supply reference services (that is, the tariffed transmission service) in accordance with the schedules 1 and 5 of the Tariff Order (which set out the initial reference tariffs and the tariff control formula).

In contrast, the WTS does not refer to any external documents in relation to the terms and conditions of providing the reference service. The current provisions of the WTS access arrangement state that the service provider will provide tariffed transmission services to users in accordance with schedules 1 and 4 of the access arrangement (which set out the initial reference tariffs and the tariff control formula). In addition, the terms and conditions of supply must be consistent with the pro-forma Western Transmission System Agreement (at appendix 2 of the access arrangement).

11.2.3 GasNet proposal

GasNet proposes to revise the access arrangements to state that 'terms and conditions on which the Reference Service is supplied are as set out in the MSO Rules from time to time'.[391] It also states that the obligations to comply with section 3.6 of the Code are allocated to VENCorp.

GasNet views the reference service as containing two components. One component is VENCorp services (provided by VENCorp to users according to the VENCorp access arrangement) and the other is the tariffed transmission service (that is, GasNet providing the pipeline system to VENCorp in accordance with the SEA).

The effect of the SEA is that VENCorp has the operational control of the entire pipeline system. GasNet and VENCorp propose to extend the SEA to the current WTS if the Commission agrees with their proposal that the PTS and WTS be covered by the one access arrangement. The parties have also agreed to extend the term of the SEA to 31 December 2007 to coincide with the proposed conclusion of the forthcoming access arrangement period.[392]

11.2.4 Submissions

VENCorp states that it has prepared revisions to its access arrangement on the basis that:

> … GasNet will continue to describe in its access arrangement the transmission services and capacity provided to VENCorp, as a current User of these services. To the extent that GasNet does not do so, the access arrangements may be inconsistent in their current form. VENCorp's strong preference remains for GasNet to include the Service Envelope Agreement, or at least key obligations from that agreement, in GasNet's access arrangement. This position was strongly supported by market participants as Users during VENCorp's recent public pre-consultation on its access arrangements.[393]

In a subsequent submission, VENCorp noted that GasNet has not provided any terms and conditions in its access arrangement and has only referred to the MSOR.

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[391] GasNet access arrangement, 27 March 2002, p. 4.

[392] GasNet submission, 27 March 2002, pp. 10-11.

[393] VENCorp submission, 28 March 2002, p. 4.

VENCorp considers this to be too general as it ‘does not describe in sufficient detail for users the actual services provided by GasNet, and ignores the terms and conditions of the Service Envelope Agreement’.[394]

Legal advice obtained by VENCorp suggests that not only must an access arrangement specify the reference services offered by the service provider (see section 11.1 above), it must include the terms and conditions on which those services are provided.[395] VENCorp suggests that compliance with the Code can be obtained by GasNet ‘including in its access arrangement either the entire Service Envelope Agreement, or describing the key obligations from that agreement’.[396]

Similarly, BHP Billiton stated ‘the aggregated “terms and conditions” applying to the aggregated services need to be presented. It is not the role of the ACCC nor of users to make their own decisions and estimates of the cost and conditions applying to the full service’.[397]

ENERGEX comments that the SEA is not publicly available and states that it:

> … understands it is ostensibly a bilateral contract describing the manner in which transmission pipeline assets will be made available for the operator to use. If this understanding is correct, there would appear to be no reason why the contents of the SEA should not form part of the public access application (of both VENCorp and GasNet).[398]

TXU regards the proposed revised access arrangement as flawed as it does not provide a description of reference services, does not recognise the relationship between users and GasNet and potentially avoids valid access dispute resolution processes.[399] It suggests that the revised access arrangement should include a clear description of services, the SEA or key obligations from the agreement. TXU also expresses concern regarding GasNet’s reference to the MSOR:

> The MSO Rules do not of themselves impose clear obligations on GasNet to ensure that GasNet maintains the system and provides the transportation and capacity services required by TXU and other users. Similarly, GasNet has a wide discretion outside the role of VENCorp under the MSO Rules in relation to extensions and expansions. Therefore, it is not enough for GasNet to assert that the terms and conditions will be the MSO Rules as in force from time to time.[400]

BHP Billiton suggests that with three sets of terms and conditions applying to gas transmission (that is, those from GasNet, VENCorp and the MSOR) confusion and potential conflict is likely. Consequently, it suggests that ‘a single set of all-encompassing rules, rights and obligations of the three parties to the Victorian gas

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394 VENCorp submission, 13 May 2002, p. 6.

395 ibid., advice provided by Corrs Chambers Westgarth, 30 April 2002, p. 7.

396 VENCorp submission, 13 May 2002, p. 3.

397 BHP Billiton submission, 17 May 2002, p. 9.

398 ENERGEX submission, 9 May 2002, p. 1.

399 In response, GasNet states that its proposed changes ‘will have no material effect on the access of Users to an enforceable dispute resolution process’ and notes that the SEA includes a dispute resolution process for disputes between GasNet and VENCorp. GasNet response to submissions, 12 June 2002, p. 4.

400 TXU submission, 31 May 2002, p. 4.

access arrangements' is needed. In addition, BHP Billiton recommends an open forum to discuss the appropriateness of these rules.[401]

11.2.5 Commission's considerations

Submissions provided by interested parties indicate that there is some concern among market participants about the proposal from GasNet to exclude terms and conditions from its revised access arrangement. In particular, the inclusion of the SEA (in full, or its key features) in the access arrangement has been suggested.

The 1998 SEA is available from the Commission's website. However, as noted above, the Commission understands that the parties intend to make some changes to the current agreement. The Commission has not been advised as to whether the amended SEA will be publicly available.

In general, the Commission would expect an access arrangement to contain all the information regarding access to the services provided by the pipeline for users and prospective users. However, it acknowledges that inclusion of the complete SEA in GasNet's access arrangement may be inappropriate as it might place unnecessary restrictions on the commercial relationships between GasNet and VENCorp.

The Commission has concluded that GasNet's access arrangement should continue to provide a reference service. Consequently, the proposed revised access arrangement for the PTS should include the terms and conditions upon which access to the pipeline's services will be made available.

The Commission considers that the revised access arrangement proposed by GasNet is incomplete and does not meet the requirements of the Code as it does not contain the terms and conditions upon which the reference service (known as the tariffed transmission service) will be made available to VENCorp. The Commission has concluded that GasNet should state that the terms and conditions on which GasNet supplies the services to VENCorp are set out in the SEA and the MSOR.

Accordingly, the Commission proposes the following amendment to the revised access arrangement.

Proposed amendment 34

GasNet must amend clause 8.1 of its revised access arrangement, terms and conditions, to include the terms and conditions on which GasNet supplies the services to VENCorp (which in turn are set out in the SEA and the MSOR).

401 BHP Billiton submission, 21 June 2002, p. 38.

11.3 Extensions and expansions policy

11.3.1 Code requirements

The Code requires an access arrangement to have an extensions and expansions policy (section 3.16). The policy is to set out the methodology used to assess whether any extensions to, or expansion of, the capacity of the system will be treated as part of the covered pipeline for the purposes of the Code.

A service provider is also required to specify the impact on reference tariffs of including an extension or expansion as part of the covered pipeline.[402] In addition, an extensions and expansions policy must outline under what conditions the service provider will fund any new facilities and provide a description of these new facilities.

11.3.2 Current access arrangement provisions

The current provisions of the PTS and WTS access arrangements state that all expansions to the systems will be covered by the relevant access arrangements. Significant extensions, that is where the cost is greater than $5 million or the extension is longer that 10 km, may be excluded from the relevant access arrangement if the service provider notifies the Commission, before the extension comes into service, that the extension will not form part of the access arrangement. The ability to elect coverage of an extension is not available for extensions that have been included in the calculation of reference tariffs or, pursuant to clause 5.7.1(f) of the PTS access arrangement, the Interconnect.

Regardless of whether an extension or expansion is to be included in an access arrangement, GasNet is required (under clause 5.7.1 of the PTS access arrangement) to notify the Commission of the location, cost and length of a new extension or expansion prior to it coming into service.

The cost of an extension or expansion will be included in the capital base if it passes the economic feasibility test (as determined by the Commission pursuant to a revision application under section 2.28 of the Code). Users will be charged the current reference tariff. Alternatively, the proportion of the cost that passes the economic feasibility test may be included in the capital base. The remaining proportion may be recovered by a surcharge, a capital contribution, included in the speculative investment fund or any combination of these.

The policies also allow extensions and expansions that do not pass the economic feasibility test to be included in the capital base of the relevant access arrangement in some circumstances. The Commission must be satisfied that either system wide benefits arise from the investment which justify higher tariffs for all users or that the investment is necessary on the basis of maintaining the safety, integrity or contracted capacity of the reference services.

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402 For example, reference tariffs may remain unchanged, but a surcharge may be levied on incremental users.

11.3.3 GasNet proposal

Consistent with the current provisions, GasNet proposes that all expansions to the pipeline system be included in the access arrangement. GasNet would continue to be required to notify the Commission of any new extension or expansion prior to it commencing service.

The first amendment proposed by GasNet is that the ability to exclude an extension from coverage of the access arrangement be provided for all extensions (with the exception of those included in the calculation of reference tariffs).[403]

GasNet considers that the current threshold test, which requires all small extensions to be included in the access arrangement, has the effect of deterring investment in small pipelines and is ‘unduly restrictive’. GasNet states that:

> … extending coverage to small laterals is implicitly allowing for open access to these laterals. This is incompatible with the nature of those pipelines which are essentially service lines to a specific customer. GasNet is at a severe disadvantage in tendering to build these laterals as alternate pipeline companies can offer a dedicated pipeline to the prospective User.[404]

A service line is a pipeline from a shared pipeline to a specific end user. While many service lines are part of a distribution network, dedicated high pressure pipelines to large users will become part of a transmission system. GasNet states that in 1998 there were four service lines to single customers. There have since been two tenders, one of which GasNet won. GasNet expects approximately three service laterals to be required over the forthcoming access arrangement period.

GasNet regards the current policy as creating a situation where it is at a commercial disadvantage in tendering for service lines. Firstly, the user cannot obtain exclusive, or favoured, rights to the capacity of the service line under the market carriage system. Although it may be unlikely that a third party would seek to access a service line, GasNet considers that a user will see uncertainties in a GasNet bid to build a service line.

Secondly, GasNet considers it is restricted in the tariff proposal it is able to offer a potential user of a service line. As the lateral will, under the current extensions and expansions policy become part of the covered pipeline and be included in the access arrangement, a tariff is to be described in terms of the relevant reference tariff and a surcharge. However, GasNet states that it is only able to make assumptions about the tariff and surcharge since they require approval by the Commission. Accordingly, GasNet considers that it is currently at a disadvantage to other pipeline businesses in tendering for service lines and seeks to remove the current policy that all small extensions become part of the covered pipeline and the access arrangement.[405]

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[403] GasNet has proposed to include forecast capital expenditure of approximately $1.5 million per year for small lateral pipelines. GasNet access arrangement information, 27 March 2002, p. 12. See section 6.3 of this Draft Decision.

[404] GasNet submission, 27 March 2002, p. 113.

[405] GasNet response to Commission, 9 May 2002.

The second amendment for this policy proposed by GasNet is regarding the impact of extensions and expansions on reference tariffs. The current detailed clauses would be replaced with a clause stating that GasNet may submit revisions to the Commission seeking to include the costs of extensions and expansions in the capital base. These revisions would only be considered under the relevant provisions (that is, sections 8.15 to 8.16) of the Code.

GasNet proposes to retain the ability to undertake new facilities investment that does not satisfy section 8.16 of the Code.

11.3.4 Submissions

GasNet's proposal to include all expansions in the access arrangement received little comment from interested parties with the exception of VENCorp who states that 'there should be no room for discretion regarding expansions'.[406] In addition, VENCorp suggested that the access arrangement should make explicit provision for any expansion to the pipeline system to be 'dealt with under the Service Envelope Agreement and MSO Rules, as it does in its current access arrangement'.[407]

ENERGEX states that it 'does not agree that GasNet should have unilateral rights to determine whether future extensions should be covered'.[408] It notes that the Code and the Commission have processes in place to assess extensions and indicated that these should be followed.

EnergyAdvice expresses concern regarding the impact of the proposed extensions and expansions policy on new laterals dedicated to end users. In a scenario where an end user pays GasNet the capital cost of building a lateral and the lateral becomes part of the covered pipeline, EnergyAdvice is concerned that the end user will not obtain 'absolute capacity rights'. It also suggests that third party users will have access to the lateral 'but are not required to reimburse the initial end user'.

Alternatively, EnergyAdvice notes that the end user could contract with a party other than GasNet to build the lateral and then arrange for the operation of the pipeline with GasNet. While this provides the end user with exclusive rights to the lateral, EnergyAdvice suggests that this option is not favoured 'as it is a cumbersome alternative and excludes others that could be supplied using spare capacity'. EnergyAdvice concludes:

> There needs to be a balance between protecting foundation end users who pay for or contribute to the cost of pipelines, access provisions that are equitable, and conditions that encourage efficient capital expenditure. We doubt that the current policy achieves this.[409]

11.3.5 Commission's considerations

As noted in section 11.3.3 above, GasNet proposes to continue with the current policy that all expansions be included in the access arrangement. The Commission generally

[406] VENCorp submission, 13 May 2002, p. 15.

[407] ibid., p. 15. TXU also expressed this view: TXU submission, 31 May 2002, p. 38.

[408] ENERGEX submission, 9 May 2002, p. 5.

[409] EnergyAdvice submission, 30 May 2002, p. 11.

prefers this approach and agrees with VENCorp's view that it is not appropriate to have discretion regarding new expansions of a pipeline system.[410]

The Commission notes VENCorp's suggestion that GasNet's extensions and expansions policy currently explicitly provides that expansions will be dealt with under the SEA and the MSOR and that this should continue. However, GasNet's extensions and expansions policy does not currently provide for this. The Commission understands that the current SEA provides for the inclusion of extensions and expansions to the pipeline system in the SEA so that an accurate SEA remains in effect between GasNet and VENCorp. This is also reflected in chapter 5 of the MSOR. The Commission is not aware that these clauses have been inadequate during the initial access arrangement period with respect to the relationship between GasNet and VENCorp. Accordingly, the Commission does not propose to amend the access arrangement as suggested by VENCorp and TXU.

GasNet has suggested that it may face difficulties in tendering for service lines in the future if the current threshold assessment of extensions remains in place. EnergyAdvice has also expressed concern regarding the impact on users of service lines. The Commission is not convinced that the current policy places GasNet at a significant disadvantage as it suggests. Similarly, the Commission does not consider users of service lines under significant disadvantage pursuant to the current policy. It does agree with EnergyAdvice however, that a balance between foundation users and third party users should be found.

While the issue has not been raised by GasNet or in submissions, the Commission notes that automatic coverage of an extension may complicate any bids by GasNet under the competitive tender provisions of the Code.

The Commission considers that it is appropriate that a service provider retains discretion as to whether extensions to its pipeline system become part of the covered pipeline and be included in the relevant access arrangement. Accordingly, the Commission proposes to accept GasNet's proposed revisions to the current extensions and expansions policy to this effect.

It should be noted in relation to the concerns raised by ENERGEX, that any extension that a service provider seeks to include in an access arrangement would be required to satisfy the requirements of section 8.16 of the Code. In addition, it may be possible to regard an extension as a separate pipeline, allowing any party to apply to the National Competition Council for coverage under the Code. The revised extensions and expansions policy would not circumvent these Code provisions.

The second proposed revisions to the extensions and expansions policy relate to the tests that new facilities investments must satisfy in order to be incorporated into the capital base. The Commission has found that the current provisions of the access arrangements are more restrictive than the new facilities investment provisions of the Code. The current access arrangement provisions only provide for a partial inclusion of a new facilities investment into the capital base under the economic feasibility test.

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[410] See ACCC, *Final Decision: access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 12 September 2001, pp. 170-172.

Partial roll in of costs to the capital base and use of the speculative investment fund are not available under the system wide benefits or safety, integrity or contracted capacity tests. In contrast, the Code does not preclude partial roll in of costs to the capital base under any of the three tests of section 8.16(b).

The service provider may have considered this limitation appropriate at the time of the initial assessment of the access arrangement and the Commission accepted this. However, GasNet now proposes to lift the current limitations and use the new facilities investment provisions of the Code when seeking to increase the capital base with the cost of extensions or expansions.

The Commission does not consider that the more restrictive provisions currently contained in the access arrangements are necessary. The new facilities investment provisions of the Code are appropriate. The Commission proposes to accept this proposed revision to the access arrangements.

11.4 Review of the access arrangement

11.4.1 Code requirements

Section 3.17 of the Code requires an access arrangement to include a date upon which the service provider must submit revisions to its access arrangement to the regulator (revisions submission date). The access arrangement must also include a date upon which the revisions are intended to commence (revisions commencement date).[411]

The regulator's assessment of the appropriateness of the two dates must include reference to the objectives contained in section 8.1 of the Code. The regulator may, with reference to these objectives, require an earlier or later revisions submission date or revisions commencement date. It may also require that a specific major event be a trigger that compels the service provider to submit revisions prior to the revisions submission date.

11.4.2 Current access arrangement provisions

The current provisions of the access arrangements specify 31 March 2002 as the revisions submission date and 1 January 2003 as the revisions commencement date. The Tariff Order suggests that the second access arrangement period will expire on 31 December 2007.

11.4.3 GasNet proposal

GasNet proposes that the new revisions submission date be 31 March 2007 and the revisions commencement date be 1 January 2008. If the revised access arrangement commences on 1 January 2003 as currently proposed the new access arrangement period will be five years.

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[411] Revisions come into effect on the date specified by the regulator in its decision to approve the revisions, which must be at least 14 days after the decision, or the revisions commencement date. Section 2.48 of the Code.

GasNet has noted in its submission that a five year period is consistent with general regulatory practice and, in particular, coincides with the expiration of the SEA with VENCorp. In addition, it notes that the Tariff Order defines 'subsequent access arrangement period' as being five years from 1 January 2003.[412]

Clause 5.9 of the proposed revised VENCorp access arrangement specifies the same revisions submission date and revisions commencement date.

11.4.4 Submissions

The Commission has not received any submissions regarding this aspect of the proposed revisions.

11.4.5 Commission's considerations

The Commission has considered the appropriateness of the two dates in terms of the objectives contained in section 8.1 of the Code. It considers that a five year access arrangement period is consistent with these objectives.

The Commission notes that the ESC has proposed an eleven month period for assessment of the second reset for the Victorian gas distribution businesses. It is the Commission's view that such a duration would be commensurate with the current review process. However, it expects that the regulatory arrangements affecting GasNet will be well established by 2008, and that a review period of nine months as proposed by GasNet should be adequate. GasNet has the discretion to submit its revisions at an earlier date if it considers this is warranted.

Consequently, the Commission considers that the proposed dates for the revisions submission date and revisions commencement date are appropriate for the revised access arrangement and does not propose any amendment to this clause.

11.5 Other non-tariff issues

The Code also requires an access arrangement to contain a capacity management policy, a trading policy and a queuing policy. These policies relating to GasNet's proposed revised access arrangement are discussed together below.

11.5.1 Code requirements

The Code (sections 3.7 and 3.8) requires that an access arrangement specify the capacity management policy that applies to the pipeline. The pipeline must be either a contract carriage pipeline or a market carriage pipeline. If the pipeline is to operate as a market carriage pipeline then consent from the relevant minister must be obtained and provided to the regulator.

412 GasNet submission, 27 March 2002, p. 127.

If a pipeline is a contract carriage pipeline then the access arrangement must include a trading policy that explains the rights of users to trade their rights to obtain a service with other users (see section 3.9 of the Code).

Pursuant to sections 3.12 to 3.15 of the Code, an access arrangement must include a queuing policy. This policy is to be used to determine the priority given to users and prospective users for obtaining access to a covered pipeline and for seeking dispute resolution under section 6 of the Code.

11.5.2 Current access arrangement provisions

Clause 5.5 of the current PTS access arrangement states that the pipeline is a market carriage pipeline. Consequently, it does not include a trading policy. The responsibility for establishing a queuing policy for the pipeline is currently allocated to VENCorp under clause 5.6 of the PTS access arrangement.

Clause 5.5 of the current WTS access arrangement states that the pipeline is a contract carriage pipeline. It also foreshadows that the WTS will become a market carriage pipeline following the construction of the Southwest Pipeline by which it will connect to the PTS.

The current WTS access arrangement also includes a trading policy and queuing policy. Both of these policies were found to meet the requirements of the Code by the Commission in its initial assessment of the access arrangement.

11.5.3 GasNet proposal

Clause 8.2 of the proposed revised access arrangement states that the PTS (which includes the pipelines formally referred to as the PTS and WTS) is a market carriage pipeline. Both the NSW and Victorian Ministers have consented to this capacity management policy applying for the duration of the forthcoming access arrangement period.[413]

Clause 8.3 of the proposed revised access arrangement states that the responsibility for complying with the trading policy requirements of the Code is allocated to VENCorp. However, GasNet’s submission notes that, as the pipeline is a market carriage pipeline, a trading policy is not required.[414]

The queuing policy obligations for the PTS would continue to be allocated to VENCorp.

11.5.4 Submissions

No substantive issues have been raised by interested parties regarding these policies.

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[413] ibid., p. 126.

[414] ibid., p. 126.

11.5.5 Commission’s considerations

The Commission proposes to accept that the current capacity management policy of market carriage continues to apply for the PTS. In forming one pipeline system from the former PTS and WTS, the WTS will become a market carriage pipeline. The Commission considers that this is appropriate and notes that it has received copies of the ministerial letters of consent pursuant to section 3.8 of the Code from the relevant Victorian and NSW ministers.

While the application of a market carriage capacity management system in Victoria attracted considerable attention at the time of the initial assessment of the access arrangements, the Commission has received little comment during the current assessment process. As outlined in chapter 2 of this Draft Decision, the Commission considers that the most appropriate forum to review the appropriateness of the market carriage system will be the forthcoming review pursuant to the Victorian GIA. Accordingly, the Commission proposes to accept the continued adoption of a market carriage capacity management system for the pipeline.

As noted by VENCorp in its proposed revised access arrangement, the Code does not require a trading policy for the pipeline. While GasNet acknowledges this in its submission, its proposed revised access arrangement incorrectly states that VENCorp has responsibility for a trading policy. Accordingly, the Commission proposes that GasNet amend its revised access arrangement to correct this anomaly.

Proposed amendment 35

GasNet must amend clause 8.3 of its revised access arrangement to remove the current allocation of responsibility of a trading policy to VENCorp.

The Commission agrees that it is appropriate that VENCorp continues to be responsible for the PTS queuing policy. This policy is set out in section 5.7 of the proposed revised access arrangement lodged by VENCorp and clause 5.3 of the MSOR. It is discussed in the Commission’s draft decision document relating to that application.

Part D – Decision

12. Decision

Pursuant to section 2.35(b) of the Code, the Commission proposes not to approve the proposed revised access arrangement for the GasNet System lodged by GasNet Australia (Operations) Pty Ltd. The Commission's reasons for this decision are provided earlier in this Draft Decision document.

The amendments (or the nature of amendments, as appropriate) that would have to be made in order for the Commission to approve the proposed revised access arrangement are identified in the relevant sections of this Draft Decision document and are listed below.

Proposed amendment 1
GasNet must amend clause 4.6 of its revised access arrangement so that the redundant capital policy applies to both partial and wholly redundant assets.

Proposed amendment 2
GasNet must amend clauses 4.10 and 6.2 of its revised access arrangement to provide an assessment period of 40 business days. It must also allow the Commission, at its discretion, to extend the period to adequately assess pass through and zone change proposals.

Proposed amendment 3
GasNet must amend clause 6.4 of its revised access arrangement, the pass through mechanism, to allow both positive and negative pass through amounts.

Proposed amendment 4
GasNet must amend clauses 6.1 and 6.2 of its revised access arrangement, the pass through mechanism, to allow the Commission to initiate a pass through review.

Proposed amendment 5
GasNet must amend the following in its revised access arrangement:

- the definition of a Change in Taxes Event in clause 9.1 so that (b) reads 'the removal or imposition of a Relevant Tax';
- the definition of Relevant Tax so that it adopts the wording specified in section 3.2.5 of this Draft Decision;
- the definition of a Regulatory Event in clause 9.1 to allow for regulatory requirements that may result in either higher or lower costs for GasNet;
- the definition of an Insurance Event in clause 9.1 to allow for a changes in the Minimum Insurance Level that exceed or fall short of the Benchmark Insurance Costs;
- the definition of an Insurance Event in clause 9.1 to include the amounts currently identified in the asymmetric risk allowance as deductibles in current insurance; and
- clauses 6.1 and 6.2 to require the provision of sufficient documentary evidence which substantiates that the aggregate costs facing GasNet has increased or decreased as a consequence of the deemed pass through event .

Proposed amendment 6
GasNet must calculate the roll forward of the regulatory asset base on the basis of the initial capital base of $358.0 million (at 1 January 1998) which was approved in the 1998 Final Approval.

Proposed amendment 7
GasNet must amend its revised access arrangement to include tariffs for the Southwest Pipeline which are approximately 10 per cent higher than those on the Longford to Pakenham Pipeline. In addition, the tariffs for the Southwest Pipeline are to be calculated on the basis of full levelisation over 20 years.

Proposed amendment 8
GasNet must adopt the Commission's CAPM parameters as set out in Table 5.3 of this Draft Decision to more accurately reflect the current financial market settings. GasNet must use the real vanilla WACC of 6.4 per cent to calculate the return on asset component of revenues for its revised access arrangement.

Proposed amendment 9
GasNet must amend Table 8-3 and section 8.3.4 of its submission relating to exceptional costs to reflect only the portion of costs that relate to regulated assets. It must also change operations and maintenance cost forecasts in its access arrangement information to reflect these changes.

Proposed amendment 10
GasNet must amend section 3.5 of its revised access arrangement information so that operations and maintenance cost forecasts do not include the annual recovery of litigation expenses.

Proposed amendment 11
GasNet must amend section 3 of its revised access arrangement information so that operations and maintenance costs in 2003 include a recovery for regulatory review costs incurred in 2001 and 2002. GasNet must publicly provide a detailed itemised breakdown of these costs so that the Commission and interested parties can assess whether or not these costs are prudent.

Proposed amendment 12
GasNet must amend section 3 of its revised access arrangement information to include an allowance for equity raising costs of 0.48 per cent of regulated equity, to be recovered as an annual non capital cost cash flow. It must also amend its revised access arrangement to exclude an allowance for debt raising costs in non capital expenditure cash flows and add 8 basis points to the debt margin for these costs.

Proposed amendment 13
GasNet must amend section 3.5 of its revised access arrangement information so that the estimated K factor under-recovery to be recovered in benchmark revenues is $10 359 839 in 2002 dollars adjusted to 2003 dollars using the formula noted in schedule 5 of the Tariff Order. GasNet must also amend section 3.5 of its revised access arrangement information to state that annual tariffs set for 2003 will be adjusted to reflect the 2002 K factor carryover, which will be calculated at the annual tariff review process at the end of 2002.

Proposed amendment 14
GasNet must amend clause 4.9 of schedule 4 of its revised access arrangement so that the Maximum Price for each Transmission Tariff Component (MPTC) in 'step 3' can increase by only one per cent (0.01) above the MPTC in 'step 2'.

Proposed amendment 15
GasNet must include in clause 4, reference tariff policy, of its revised access arrangement:

- explicit confirmation that the business will self-insure;
- details that clearly specify the self-insured risks consistent with this Draft Decision; and
- explicit confirmation that future actual costs relating to these identified events will not be included in future regulatory cash flows.

Proposed amendment 16
GasNet must amend section 3.5 of its revised access arrangement information to exclude the $140 000 annual allowance for Deductibles in current insurance arrangements from the cash flows.

Proposed amendment 17
GasNet must amend clause 3.5 of its revised access arrangement information so that the allowance for asymmetric risks is $22 000 (in 2003 dollars) a year for each year of the access arrangement period.

Proposed amendment 18
GasNet must amend section 3.5 of its revised access arrangement information to remove the proposed allowance for working capital from its revenue calculations.

Proposed amendment 19
GasNet must amend section 3.6 of its revised access arrangement information to exclude any forecast expenditure relating to the Brooklyn loop from the calculation of tariffs.

Proposed amendment 20
GasNet must amend section 3.6 of its revised access arrangement information to exclude any forecast expenditure relating to stage two of the proposed Lurgi pipeline rehabilitation project from the calculation of tariffs.

Proposed amendment 21
GasNet must amend section 3.6 of its revised access arrangement information to exclude forecast capital expenditure relating to service lines for 2002 to 2007 from the calculation of tariffs.

Proposed amendment 22
GasNet must amend section 3.3 of its revised access arrangement information to retain the current depreciation schedule for the Longford pipeline with a remaining economic life ending in 2030.

Proposed amendment 23
GasNet must amend section 4 of its revised access arrangement information to include forecast flows from the Yolla field in its flow assumptions from 2004.

Proposed amendment 24
GasNet must amend section 5.3 of its revised access arrangement information to allocate the K factor under-recovery of $10 835 874 million (in 2003 dollars) to all tariffs (other than those for the Southwest Pipeline) as a uniform percentage increase.

Proposed amendment 25
GasNet must amend section 5.3 of its revised access arrangement information to allocate capital raising costs on the same basis as it allocates depreciation and return on capital.

Proposed amendment 26
GasNet must amend clause 1.3(f), schedule 1 of its revised access arrangement to require the provision of sufficient evidence to the Commission to support a claim that a specific bypass threat is credible. In addition, it must state that the introduction of the Warrnambool and Koroit prudent discounts would be subject to the Commission’s approval.

Proposed amendment 27
GasNet must amend schedule 3 to its revised access arrangement so that the annual tariff review time frames currently in clause 6.1 of the Tariff Order are retained.

Proposed amendment 28
GasNet must amend schedule 3 of its revised access arrangement to include the provisions currently in clauses 6.1(a)(1)(B) and 6.1(f)(2) of the Tariff Order.

Proposed amendment 29
GasNet must amend section 3.5 of the access arrangement information to include actual historical operations and maintenance costs for each of the years 1998 to 2001, and current best estimates for 2002.

Proposed amendment 30
GasNet must amend clause 7.2 of its revised access arrangement so that the benefit sharing allowance calculated for the third access arrangement period is based on the rolling carryover mechanism. The amended mechanism must:

- allow GasNet to keep unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years;
- allow for the carryover of <u>both</u> unanticipated efficiency gains and losses;
- make no distinction between controllable and uncontrollable gains (losses);
- determine operations and maintenance expenditure achieved by GasNet in 2007 by taking 2006 actuals and adjusting these by the change in expenditure forecast to occur between 2006 and 2007;
- not allow an adjustment for volume growth, except for operations and maintenance costs associated with capital expenditure deemed prudent and rolled into the asset base; and
- ensure that all amounts are expressed in 2008 dollars.

Proposed amendment 31
GasNet must amend section 3.5 of its revised access arrangement information to remove any benefit sharing allowance associated with the first access arrangement period.

Proposed amendment 32
GasNet must amend section 6 of its access arrangement information to include operations and maintenance costs/TJ/km data in its comparison of Australian KPIs.

Proposed amendment 33
GasNet must amend clause 3 of its revised access arrangement, services policy, to include the services that GasNet supplies to VENCorp (that is, making the PTS available to VENCorp in accordance with the SEA and the MSOR). In addition, the reference ‘VENCorp Services’ in clause 3.2 must be changed to ‘VENCorp Reference Services’.

Proposed amendment 34

GasNet must amend clause 8.1 of its revised access arrangement, terms and conditions, to include the terms and conditions on which GasNet supplies the services to VENCorp (which in turn are set out in the SEA and the MSOR).

Proposed amendment 35

GasNet must amend clause 8.3 of its revised access arrangement to remove the current allocation of responsibility of a trading policy to VENCorp.

Appendix A: Submissions

The following interested parties provided submissions.

TXU Australia	3 May 2002
ENERGEX Retail	9 May 2002
AGL Energy Sales and Marketing	9 May 2002
VENCorp	13 May 2002
Duke Energy International	13 May 2002
Pulse United Energy	16 May 2002
Origin Energy	17 May 2002
BHP Billiton	17 May 2002
Victorian Department of Natural Resources and Environment	20 May 2002
EnergyAdvice[415]	30 May 2002
TXU	31 May 2002
Energy Action Group	31 May 2002
Energy Users Association of Australia	4 June 2002
The Allen Consulting Group[416]	5 June 2002
BHP Billiton	21 June 2002
Amcor and PaperlinX	24 June 2002
Energy Users Association of Australia	11 July 2002
BHP Billiton	18 July 2002
Bob Lim & Co and Headberry Partners[417]	30 July 2002

415 On behalf of ACI Glass Packaging, Barrett Burston, Bonlac Foods, Cabot, CSR Limited, Insulation Solutions, Mobil Altona Refinery, Norske Skog, Overall Forge, Pilkington Glass, Qenos, Tatura Milk.

416 On behalf of ExxonMobil.

417 On behalf of BHP Billiton Petroleum and Electricity Consumers Coalition of South Australia.

Appendix B: Consultants

The following consultants assisted the Commission in relation to this Draft Decision.

The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, July 2002.

Dr Martin Lally, *Determining the risk free rate for regulated companies*, July 2002.

Appendix C: Attachment A to the Code

Information disclosure by a service provider to interested parties

Pursuant to section 2.7 the following categories of information must be included in the Access Arrangement Information.

The specific items of information listed under each category are examples of the minimum disclosure requirements applicable to that category but, pursuant to sections 2.8 and 2.9, the Relevant Regulator may:

- allow some of the information disclosed to be categorised or aggregated; and
- not require some of the specific items of information to be disclosed,

if in the Relevant Regulator's opinion it is necessary in order to ensure the disclosure of the information is not unduly harmful to the legitimate business interests of the service provider or a user or Prospective user.

Category 1: Information Regarding Access & Pricing Principles

Tariff determination methodology
Cost allocation approach
Incentive structures

Category 2: Information Regarding Capital Costs

Asset values for each pricing zone, service or category of asset
Information as to asset valuation methodologies - historical cost or asset valuation
Assumptions on economic life of asset for depreciation
Depreciation
Accumulated depreciation
Committed capital works and capital investment
Description of nature and justification for planned capital investment
Rates of return - on equity and on debt
Capital structure - debt/equity split assumed
Equity returns assumed - variables used in derivation
Debt costs assumed - variables used in derivation

Category 3: Information Regarding Operations & Maintenance

Fixed versus variable costs
Cost allocation between zones, services or categories of asset & between regulated/unregulated
Wages & Salaries - by pricing zone, service or category of asset
Cost of services by others including rental equipment
Gas used in operations - unaccounted for gas to be separated from compressor fuel
Materials & supply
Property taxes

Category 4: Information Regarding Overheads & Marketing Costs

Total service provider costs at corporate level
Allocation of costs between regulated/unregulated segments
Allocation of costs between particular zones, services or categories of asset

Category 5: Information Regarding System Capacity & Volume Assumptions

Description of system capabilities
Map of piping system - pipe sizes, distances and maximum delivery capability
Average daily and peak demand at "city gates" defined by volume and pressure
Total annual volume delivered - existing term and expected future volumes
Annual volume across each pricing zone, service or category of asset
System load profile by month in each pricing zone, service or category of asset
Total number of customers in each pricing zone, service or category of asset

Category 6: Information Regarding Key Performance Indicators

Industry KPIs used by the service provider to justify "reasonably incurred" costs
Service provider's KPIs for each pricing zone, service or category of asset

Appendix D: Map of GasNet system