Australian Competition & Consumer Commission

Draft Decision

Revised access arrangement by GasNet Australia Ltd for the Principal Transmission System

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Commissioners

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Preface

On 30 April 2007, GasNet Australia submitted a revised access arrangement (AA) for the Victorian Principal Transmission System (PTS) for the AA period 2008–12 to the Australian Competition and Consumer Commission (ACCC) for approval under the *National Third Party Access Code for Natural Gas Pipelines* (the code). This is the ACCC's second scheduled review, following the second AA approved in 2002. This draft decision proposes not to accept GasNet's revisions as submitted and proposes amendments the ACCC considers necessary before the revised AA can be approved in accordance with the code.

The PTS is the main high pressure gas transmission pipeline network in Victoria and is owned and maintained by GasNet Australia, and operated by the Victorian Energy Networks Corporation (VENCorp). The PTS is a covered pipeline under the code and is also subject to a market carriage capacity management system, where users are normally charged for actual usage and not on a contractual basis for a specified quantity of service.

Until recently, both GasNet and VENCorp were service providers under the code. The responsibilities for the PTS which the code imposed upon them were shared between their AAs. However, legislation recently introduced in 2007 by the Victorian Government has removed the requirement for VENCorp to submit an AA to the ACCC for approval. Instead, it is now expected that VENCorp will continue to operate the PTS in accordance with the Market and System Operations Rules (MSO rules) and be responsible for the queuing policy (which sets out the policy for the allocation of spare and developable capacity), but will no longer have a direct commercial relationship with gas users. This means the gas transportation deeds (GTD), which provide terms and conditions in respect of the gas transportation service for users' will now cover arrangements between GasNet and users rather than VENCorp and users. This requires GasNet to now include GTDs as part of its AA, whereas previously they were included as part of VENCorp's AA.

GasNet proposes to increase reference tariffs between the AA2 and AA3 periods in real terms by 36 per cent on average, from $0.29/GJ (the average tariff at the end of the AA2 period) to $0.40/GJ (the average proposed tariff at the commencement of the AA3 period). In addition to this step change, GasNet proposes an annual real average increase for the majority of its reference tariffs of 2.8 per cent per annum over the AA3 period. Pursuant to GasNet's submission, these proposed increases can principally be attributed to:

- the actual annual volume/tariff mix outcomes during the AA2 period which required GasNet to reduce tariffs through the period, such that in 2007 tariffs were 15 per cent lower than if the original tariff path (forecast volume/tariff mix) had been followed and
- the proposed increases in operating costs (30 per cent increase) and capital expenditure (400 per cent increase) and proposed lower forecast volumes (2 per cent decrease) during the AA3 period in comparison to the AA2 period.

GasNet submits increased capital costs are required to refurbish and upgrade assets as they age and deteriorate and to augment the PTS to address anticipated breaches in the minimum system pressure requirements. Similarly, GasNet submits the increased operating costs are consistent with the expanding network and also required to recover the costs associated with changes in regulatory and technical requirements.

This draft decision accepts the majority of GasNet's refurbishment and upgrade proposals. However, the ACCC has determined that a number of GasNet's augmentation proposals can either be deferred until after the AA3 period or do not meet the requirements of the code, on the basis of an independent review prepared by Sleeman Consulting and further modelling by VENCorp. The ACCC notes GasNet has an opportunity to respond to this draft decision and justify the necessity of capex proposals and demonstrate compliance with the requirements of the code. The code also allows GasNet to submit capex proposals to the ACCC for approval at any time during the AA period.

This draft decision also accepts the majority of GasNet's proposed operating costs. However, the ACCC notes GasNet did not propose any reductions in corporate overheads resulting from cost savings expected from the APA Group's acquisition of GasNet in 2006. The ACCC proposes to reduce GasNet's corporate costs to reflect expected cost reductions.

GasNet submits aggregate volumes forecasts which are 2 per cent lower during the AA3 period than the AA2 period. This reflects the downwards impact on gas usage of weather warming and an expectation of lower gas usage by gas powered generation. This draft decision accepts the majority of GasNet's volume forecasts, with the exception of gas power generation (GPG) annual forecast volumes, which the ACCC considers do not fully reflected more recent volume growth trends as a result of the impact of the drought conditions on generation.

In relation to GPG forecast volumes, the ACCC engaged ACIL Tasman who considered these forecasts should be higher in view of the impact of the drought on generators and other anticipated generation developments in the National Electricity Market. ACIL Tasman also commented on the possibility of a comprehensive emissions trading scheme being introduced by governments towards the end of this (AA3) period. The ACCC considers it is possible that the further increased development and usage of emission schemes over time may trigger the need for potential capital expenditure to facilitate GPG expansion, which is likely to be more relevant in subsequent AA periods. ACIL Tasman, has not, however, factored any explicit increase in GPG forecast volumes as a result of an emissions-trading scheme as this is unlikely to have an impact until the following (post 2012) AA4 period.

The ACCC's draft decision to propose the reduction of GasNet's capital and operating costs and the increase of forecast volumes relative to GasNet's proposals for the AA3 period, is expected to result in an increase in the real average tariff by 16 per cent between 2007 and 2008 with a further annual increase of 2.8 per cent over the remainder of the AA2 period. This compares to GasNet's proposal of a 36 per cent increase between 2007 and 2008 and a 2.8 per cent annual increase for the remainder of the period.

The majority of the real average tariff increase between the AA periods results from an average tariff at the end of the AA2 period which was lower than expected and as initially forecast at the commencement of the AA2 period. The ACCC considers the lower average tariff at the end of the AA2 period is not sustainable. It is the result of GasNet's price control balancing the tariff over the AA2 period, rather than a reflection of an on going sustainable level for operating the system. The reduction in the 2007 average tariff level was required by GasNet's price control to repay an over-recovery earlier in the period resulting from differences between forecast and actual volume / tariff mix.

GasNet also proposes a revised price control to limit its exposure to the risk of actual volumes being higher or lower than forecast volumes. The ACCC considers that GasNet's revised form of price control is consistent with the requirements of the code and preserves an incentive for GasNet to maintain and develop the market.

GasNet proposes to amend its cost allocation methodology for deriving tariffs such that final tariff zones reflect the average direct cost associated with transporting gas along the withdrawal and injection pipelines. This contrasts with the current approach of assigning a specific direct cost to each pipeline segment over which the gas flows to a final tariff zone. GasNet also proposes to introduce a postage-stamp tariff for tariff-V (small) users and to levy the peak injection tariff on winter volumes instead of the top ten peak winter period days. This draft decision proposes not to approve these changes to GasNet's proposed cost allocation methodology and postage-stamp reference tariff-V on the basis it will result in reference tariffs which are less cost reflective in both the short run and long run. The ACCC considers ensuring tariffs are cost reflective will facilitate efficient usage and investment decisions by users and is consistent with the requirements of the code. Finally, the ACCC proposes not to approve GasNet's proposal to levy the peak injection tariff on winter volumes, as this will not provide users with the incentive to minimise usage on peak system days.

The ACCC has also identified that GasNet will receive revenue from issuing and administering AMDQ/credit certificates under the Market and System Operations Rules over the AA3 period. This revenue has not been included in GasNet's access proposal. The ACCC considers these AMDQ/credit certificates to be a service falling within the ambit of the AA, which means revenue derived from AMDQ/credit certificates should be accounted for in GasNet's proposal. In recognition of the valuable role of AMDQ/credit certificates in the context of the operation of the gas wholesale market, however, and to maintain incentives for GasNet to allocate AMDQ/credit certificates, the ACCC proposes that GasNet provide an estimate of the costs in issuing and administering these instruments to enable these costs to be recovered through its regulated revenues. While, the ACCC understands that GasNet has in the past derived revenue from issuing AMDQ/credit certificates, it does not intend to retrospectively 'clawback' any revenue that GasNet has received.

This draft decision proposes 32 amendments the ACCC considers are necessary in order for it to approve GasNet's proposed AA. Issues to which the ACCC seeks clarification have also been raised and will form part of the ACCC's considerations prior to issuing its final decision. The ACCC invites submissions to this draft decision by 14 December 2007.

It should be noted that under the Australian Energy Market Agreement between the Commonwealth and the states, a new national gas law will be introduced in 2008, which amongst other things, will change the regulatory arrangements for gas transmission and distribution networks. In the case of gas transmission networks, regulatory responsibilities will be transferred from the ACCC to the Australian Energy Regulator (AER). In the meantime, the AER has provided advice to the ACCC in its assessment of GasNet's proposed AA.

Abbreviations and glossary

AA	Access arrangement
AAI	Access arrangement information
AA1	The access arrangement approved in 1998 in which GasNet's initial capital base was set
AA2	The first scheduled revision of AA1 covering the period 2003–07
AA3	The second scheduled revision following AA2 proposed to cover the period 2008–12
AA4	The third scheduled revision following AA3 anticipated to cover the period 2013–17
ABDP	Amadeus Basin to Darwin pipeline
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
APA	APA is the Australian Securities Exchange code for Australian Pipeline Trust, GasNet's parent company
AMDQ	Authorised maximum daily quantity
AS	Australian standard
ASX	Australian Securities Exchange
bppa	Basis points per annum
capex	Capital expenditure
CAPM	Capital asset pricing model
CGS	Commonwealth Government Securities
code	National Third Party Access Code for Natural Gas Pipeline Systems
CPI	Consumer price index
DORC	Depreciated optimised replacement cost
DBNGP	Dampier to Bunbury natural gas pipeline
DVP	Dawson Valley pipeline

EAPL	East Australian Pipeline Limited
EDD	Effective degree day
EGP	Eastern Gas pipeline
ERA	Economic Regulatory Authority (Western Australia)
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
FRC	Full retail contestability
GAPR	VENCorp gas annual planning report
GJ	Gigajoule (1 000 000 000 joules)
GPG	Gas powered generation
GTD	Gas transportation deed
ICRC	Independent Competition and Regulatory Commission
IDC	Interest during construction
IPO	Initial public offer
IRR	Internal rate of return
KPI	Key performance indicators
LNG	Liquefied natural gas
m	Million
MAOP	Maximum allowable operating pressure
MAPS	Moomba to Adelaide pipeline system
MDQ	Maximum daily quantity
MCE	Ministerial Council on Energy
MRP	Market risk premium
MSP	Moomba to Sydney pipeline
MSO rules	Market and System Operations Rules
NCC	National Competition Council
NEM	National Electricity Market
NER	National Electricity Rules

NFI	New facilities investment
NPV	Net present value
opex	Operating and maintenance expenditure
PJ	Petajoule (equal to 1 000 000 Gigajoules)
PTS	Principal Transmission System (Victoria)
QCA	Queensland Competition Authority
RBA	Reserve Bank of Australia
RBP	Roma to Brisbane pipeline
SEA	Service envelope agreement
SRP	Statement of regulatory principles
SWP	Southwest pipeline
TJ	Terajoules (equal to 1 000 Gigajoules)
Tribunal	The Australian Competition Tribunal
UGS	Underground gas storage
VENCorp	Victorian Energy Networks Corporation
WAAV	Weather adjusted actual volumes
WACC	Weighted average cost of capital
WTS	Western Transmission System

Summary

Introduction

On 30 April 2007, GasNet Australia submitted a revised access arrangement (AA) for the Principal Transmission System (PTS) to the Australian Competition and Consumer Commission (ACCC) for approval under the *National Third Party Access Code for Natural Gas Pipelines* (the code). This is the ACCC's second scheduled review, following the second AA it approved in 2002.

GasNet's parent company the APA Group is the owner of the PTS and the Victorian Energy Networks Corporation (VENCorp) is the operator of the PTS, and until recently, both have been designated as service providers under the code. This would mean the terms and conditions of access to the PTS are provided in GasNet and VENCorp's AAs and the revisions leading to these AAs being considered concurrently. This arrangement, however, has been altered by proposed Victorian legislation to remove VENCorp's obligation to submit a revised AA to the relevant regulator for approval.

The PTS (also known as the GasNet system) is the primary system for the transmission of natural gas at high pressure in Victoria. The PTS is not a traditional point to point pipeline as there are a number of injections and withdrawal points. Gas injected into the PTS is primarily delivered into Victoria's gas distribution network and serves approximately 1.4 m residential users and 45 000 industrial and commercial users. In addition, a small amount of gas is exported and some gas is provided for storage.

Draft decision

After considering GasNet's proposals and submissions by interested parties, the ACCC has published this draft decision which proposes not to approve GasNet's proposed AA in its current form. This draft decision sets out the proposed amendments (or nature of the proposed amendments) which the ACCC considers are necessary in order for the proposed revised AA to be approved.

Interested parties are invited to make written submissions on this draft decision by close of business on 14 December 2007. After considering submissions the ACCC will issue its final decision which is scheduled to be published in February 2008.

Key issues

Capital base

GasNet has adjusted the capital base as at 1 January 2003 to account for actual inflation and capital expenditure in 2002 which were not known at the time of the last access review, resulting in an increase from the amount approved by the ACCC of $494.1 m to $496.18 m. In rolling this value forward over the AA2 period, GasNet proposes to include the cost of interest incurred during construction as its assets are recognised on an 'as commissioned' basis. In this context, GasNet proposes to recognise the entire cost of the Corio loop (Brooklyn Lara pipeline) as forecast new facilities investment in the AA3 period. Table A.1 details GasNet's proposed roll-forward calculation.

Table A.1: Proposal—roll-forward of the capital base

nominal $ m	*2003*	*2004*	*2005*	*2006*	*2007*
Opening capital base	**496.18**	**487.97**	**479.70**	**473.88**	**485.73**
Depreciation allowance	–20.61	–21.60	–22.81	–23.92	–24.41
Capital expenditure	0.50	0.70	3.62	20.69	48.08
Disposals/redundancies	0.00	0.02	0.00	0.00	0.00
Inflation	11.90	12.64	13.37	15.08	14.97
Closing capital base	**487.97**	**479.70**	**473.88**	**485.73**	**524.36**

Source: GasNet, *AAI 2002–07*, p. 3; data from GasNet RAB model and PTRM.

The ACCC considers the adjustments to the 2003 capital base are not appropriate. In accordance with requirements of the code, the ACCC requires GasNet to remove the benefit of return on capital associated with the difference between actual and estimated capital expenditure in 2002 that was earned over the AA2 period. However, the ACCC considers it appropriate that GasNet increase the value of its capital base for the AA3 period to reflect the value of benefits foregone over the AA2 period due to the underestimate of inflation for 2002.

The ACCC also considers that the inclusion of interest during construction and GasNet's method of estimating these costs are appropriate. The ACCC requires GasNet to recognise the amount of expenditure incurred on the Corio loop in the AA2 period and treat the remainder as forecast new facilities investment for the AA3 period. In making these changes, the ACCC has provided an indicative roll-forward calculation in table A.2.

Table A.2: Draft decision—roll-forward of the capital base

nominal $ m	*2003*	*2004*	*2005*	*2006*	*2007*
Opening capital base	**496.18**	**487.97**	**479.70**	**473.88**	**485.73**
Depreciation allowance	–20.61	–21.60	–22.81	–23.92	–24.41
Capital expenditure	0.50	0.70	3.57	20.36	94.77[c]
Disposals/redundancies	0.00	–0.02	0.00	0.00	0.00
Inflation	11.74	12.64	13.43	15.42	15.01
Closing capital base	**487.80**	**479.69**	**473.89**	**485.74**	**571.09**
Adjustment for 2002 capex overestimate					–6.91
Adjustment for 2002 inflation underestimate					0.34
Adjusted closing capital base					**564.51**

Source: ACCC analysis.

Actual capex incurred during AA2

GasNet submits of the $47.72 m of forecast capex approved by the ACCC for the AA2 period, it has incurred $32.16 m of actual capex during AA2. GasNet further submits it incurred an additional $35.42 m of non-forecast capex. GasNet proposes to roll-in all of the capex incurred during the AA2 period on the grounds the requirements of the prudent investment test and the system integrity test have been satisfied.

The ACCC has assessed the capex incurred during AA2 and agrees with GasNet that the requirements of the prudent investment test and the system integrity test have been satisfied. The main exception relates to corporate restructuring costs ($8.84 m), which GasNet submits to have been incurred as part of the APA Group's takeover of GasNet in 2006. The ACCC considers that $58.82 m of capex satisfies the requirements of the code and should be included in the capital base. Table A.3 sets out the ACCC's assessment.

Table A.3: Draft decision—AA2 actual capex incurred

2006 Dec $ m	*Forecast*	*Actual*	*Draft decision*
Forecast			
Gooding compressor refurbishment	22.21	16.03	16.03
Lurgi pipeline refurbishment	5.67	2.82	2.82
City gate upgrades and heaters	9.21	5.38	5.38
Wollert compressor station automation	2.86	2.76	2.76
Gas chromatographs	0.92	0.46	0.46
Other maintenance capex	5.97	4.70	4.70
Total forecast	**46.84**	**32.16**	**32.16**
Non-forecast			
Brooklyn compressor redevelopment	-	17.46	17.46
South Melbourne cut in	-	2.98	2.98
Wollert compressor station (miscellaneous)	-	2.15	2.15
Pig traps	-	0.72	0.72
Safety and security	-	0.79	0.96
Iona cooler upgrade	-	0.70	0.60
Regulators work	-	0.42	0.42
Maximo	-	1.37	1.37
Corporate restructuring	-	8.84	0.00

Total non-forecast	**n/a**	**35.42**	**26.66**
Total actual capex	**n/a**	**67.58**	**58.82**

Source: ACCC analysis.

Forecast capital expenditure

GasNet proposes a substantial capex program comprising augmentations and refurbishments/upgrades of $334.08 m to the PTS. This is some five times the amount actually expended in the AA2 period. The ACCC's assessment has concluded $93.10 m of GasNet's capex proposals (most which relate to refurbishment/upgrades) are reasonably expected to satisfy the requirements of the s. 8.16 of the code for inclusion as forecast capex in accordance with s. 8.20 of the code. Table A.4 details the ACCC's assessment.

Table A.4: Draft decision—AA3 forecast capex

2006 Dec $ m	*Proposal*	*Draft decision*
Augmentations		
Northern zone	79.03	0.00
Sunbury loop	12.46	0.00
Ballarat loop	29.03	0.00
Warragul loop	4.84	0.00
Pakenham loop	1.22	0.00
Stonehaven compressor	26.19	0.00
Carisbrook loop	24.05	0.00
Brooklyn Lara (Corio) pipeline	63.71	18.19
Brooklyn Wollert easements	5.37	0.00
Total augmentations	**245.90**	**18.19**
Refurbishments/upgrades		
Gas heating facilities	9.21	7.25
City gate works	6.68	6.18
Pipeline upgrades	9.65	7.65
Safety and security systems	4.25	2.93
Brooklyn compressor station	49.57	49.57
Wollert compressor station	1.58	0.05
Other compressor stations	2.96	1.29
Other	4.30	0.00
Total refurbishments/upgrades	**88.20**	**74.92**
Total capex	**334.10**	**93.11**

Source: ACCC analysis.

In order to satisfy the requirements of s. 8.16 of the code, a capex proposal must first demonstrate it is prudent, in terms of efficiency in accordance with accepted good industry practice and is designed to achieve the lowest sustainable cost of delivering services (the prudent investment test). In assessing GasNet's proposals against the prudent investment test, the ACCC has considered the independent review of GasNet's proposals prepared by Sleeman Consulting, the independent network planning and timing reports prepared by, and further advice from VENCorp. This assessment has demonstrated that a number of GasNet's capex proposals, particularly in relation to augmentation expenditures do not meet the requirements of the prudent investment test. These capex proposals include the Sunbury loop ($12.5 m), Ballart loop ($29 m), Stonehaven compressor ($26.2 m), Carisbrook loop ($24 m) and Brooklyn Wollert easements ($5.4 m), totalling $97.1 m of the $245 m augmentation expenditures proposed.

However, of those capex proposals the ACCC considers is reasonably expected to satisfy the requirements of the prudent investment test, s. 8.16 of the code further requires satisfaction against either the economic feasibility test and/or the system-wide benefits test and/or the system integrity test. In this context, GasNet submits assessment of augmentation capex against the system integrity test is justified on the grounds that addressing an anticipated breach of the minimum system pressure requirements is consistent with maintaining system integrity. The ACCC does not consider this to be an appropriate application of the system integrity test. The ACCC considers GasNet's capex proposals which purport to address an anticipated breach of the minimum system pressure requirements emanating from increased demand is principally expansive in nature and is not required to maintain the safety and integrity of services. In this regard it is necessary to distinguish between GasNet's proposed capex necessary to maintain the continuity and reliability of services at existing levels of demand from capex necessary to increase services to meet an anticipated increase in demand. The ACCC considers the appropriate assessment for GasNet's capex proposals necessary to maintain services at existing levels is against the system integrity test and for capex to increase services to meet higher demand is against the economic feasibility test.

Accordingly, of the capex proposals reasonably expected to satisfy the requirements of the prudent investment test, the ACCC accepts GasNet's submission that refurbishment/upgrade capex proposals be assessed against the system integrity test on the grounds they are consistent with maintaining the continuity and reliability of services at existing levels of demand. In relation to the augmentation capex proposals, the ACCC has withheld approval under s. 8.20 of the code pending GasNet demonstrating assessment against the economic feasibility test. These projects include a portion of the Northern zone ($79 m) and the Warragul loop ($4.4 m), totalling $83.4 m of the $245 m proposed augmentation expenditure.

Further, in the context of GasNet's proposed Northern zone augmentation, the ACCC has considered whether it is appropriate to assess an augmentation which in part restores the export capability of authorised maximum daily quantity (MDQ) across the Interconnect against the system integrity test. The ACCC notes the occurrence of unauthorised loads on the PTS has reduced the initially allocated export capability of 17 TJ/day which is largely outside GasNet's control. In the context of the legitimate expectations of GasNet and Interconnect users intending to respectively provide and obtain an allocation of AMDQ for exports, the ACCC considers the restoration of AMDQ is appropriately considered as maintaining the continuity and reliability of services, and assessment against the system integrity test is appropriate in this case.

Capital redundancy

GasNet proposes to change the definition of partially redundant assets to those that have a significantly reduced contribution to the provision of the reference service. The ACCC does not consider this appropriate as it weakens the incentive on GasNet to manage its investments and also introduces potentially ambiguous terminology.

Depreciation

GasNet proposes to extend the economic life of the Murray Valley pipeline to 2054, which is its full economic life. It also proposes to extend the economic life of the Lurgi pipeline to end in 2033 to reflect its redevelopment. GasNet does not propose to change the assumed economic life of the Longford pipeline (i.e. to end in 2023) from the ACCC's 2002 final decision for AA2.

Since GasNet's submission, information has become available which indicates that the production life of the Gippsland Basin is expected to extend beyond 2023, which affects the expected economic life of the Longford pipeline. Accordingly, the ACCC requires GasNet to amend its depreciation schedule to extend the life of the Longford pipeline to its full technical life, to end in 2029. Aside from this amendment, the ACCC considers that GasNet's proposed depreciation schedule is appropriate.

Rate of return

GasNet proposes a nominal vanilla WACC of 9.01 per cent for AA3. The ACCC considers GasNet's approach to determine the rate of return using the capital asset pricing model, including its WACC parameter proposals, is generally consistent with the requirements of the code. The ACCC has where appropriate recalculated WACC parameters using up to date data, resulting in a nominal vanilla WACC of 9.38 per cent. This is indicative for the purposes of this draft decision as these WACC parameters will be recalculated again at a date closer to the final decision.

As part of the AA revisions, GasNet formally requested the ACCC to consider the NERA reports which allege biases in the use of nominal and indexed Commonwealth Government Securities (CGS) yields to proxy the risk free rates. The ACCC has undertaken a detailed consideration of the NERA reports and received advice from the Reserve Bank of Australia (RBA) and the Australian Treasury.

On the basis of these advices, the ACCC does not consider a sufficient case has yet been demonstrated to depart from the accepted approach of using nominal CGS yields to proxy the nominal risk-free rate. However, in relation to the use of indexed CGS yields to proxy the real risk-free rate, the ACCC accepts the current demand/supply conditions in the indexed CGS market may cause market implied inflation estimates to exceed consensus forecast of inflation over the medium term. Accordingly, the ACCC considers the difference between nominal and indexed CGS yields may not result in the best estimate of the forecast inflation rate at this time. Rather, the ACCC considers a general approach having regard to replicable, transparent, objective and widely-available market data is likely to result in the best estimate of the forecast inflation rate. This has involved consideration of the RBA's target inflation range and a number of independent inflation indicators. For the purposes of this draft decision the ACCC considers this will result in a best estimate of the forecast inflation rate of 3 per cent. Table A.5 details the ACCC's assessment.

Table A.5: Draft decision—AA3 WACC parameters

WACC parameter	*Proposal*	*Draft decision*
Real risk-free rate*	2.68%	2.95%
Nominal risk-free rate*	5.85%	5.95%
Bond maturity period	10 years	10 years
Forecast inflation rate	3.09%	3.00%
Debt margin*	1.14%	1.62%
Debt raising costs	0.125%	0.104%
Credit rating	BBB	BBB
Cost of debt	7.12%	7.67%
Market risk premium	6.00%	6.00%
Gearing ratio	60:40	60:40
Value of imputation credits	0.50	0.50
Equity beta	1.00	1.00
Return on equity	11.85%	11.95%
Nominal Vanilla WACC	9.01%	9.38%
Real Vanilla WACC	5.74%	6.19%

* to be recalculated at a date closer to the final decision.

Source: ACCC analysis.

Non-capital costs

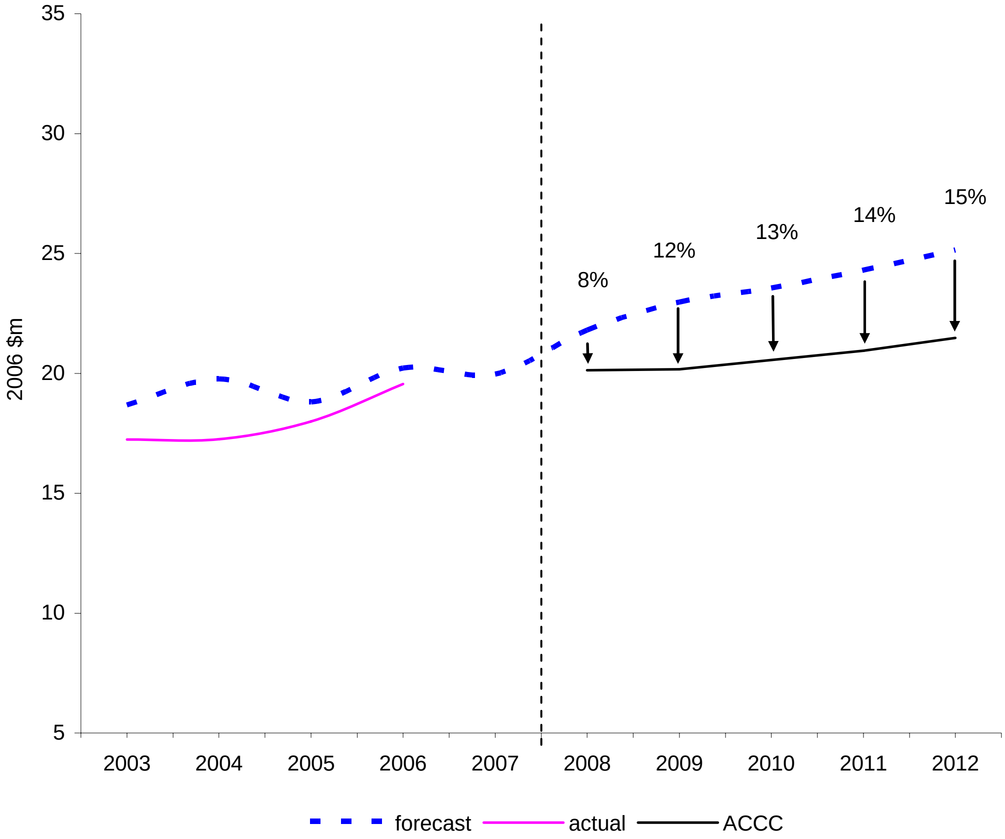
GasNet proposes substantial increases in operating and maintenance costs during the AA3 period. GasNet expects its costs to range from 17 per cent higher in real terms in 2008 than the actual costs in the base year (2006) to 35 per cent higher in 2012.

The ACCC supports many of the individual cost increases proposed by GasNet. However, the ACCC considers that GasNet should achieve costs savings in its corporate overheads following the APA Group's acquisition of GasNet in 2006. These costs savings should be achieved as GasNet is restructured and incorporated into the APA Group. GasNet has made no allowance for this in its proposed costs.

The operating and maintenance costs proposed by the ACCC are lower than those proposed by GasNet, ranging from 8 per cent lower in 2008 to 15 per cent lower in 2012. This still results in increases in operating and maintenance costs over the AA3 period by 30 per cent as compared to the AA2 period.

GasNet is forecasting a substantial increase in its fuel gas costs over actual costs incurred in 2006, almost doubling between 2006 and 2008. GasNet predicts that gas prices will rise significantly. The ACCC considers that GasNet's fuel gas costs may be highly volatile. In light of this, the ACCC proposes not to approve GasNet's proposed fuel gas costs, but instead proposes that fuel gas costs should be treated as a pass-through event. The ACCC's assessment compare to GasNet's proposals is summarised in figure A.1.

Figure A.1: Difference between GasNet and ACCC proposed non-capital costs



Pass-through events

GasNet did not give any reason for the proposed change to the definition of an insurance event. The effect would be that a change in one or more costs in insurance comprising GasNet's minimum insurance level will no longer be passed through. Instead, GasNet will bear the risk of any change to its minimum insurance level.

The ACCC supports this approach. Insurance costs are not likely to be as volatile as they were at the commencement of AA2. However, the ACCC was concerned that the definition as now proposed by GasNet created the potential for GasNet to over recover costs. Potentially GasNet could elect not to insure for certain risks currently within its Minimum Insurance Level, yet at the same time receive revenue from reference tariffs to cover the costs. The ACCC did not consider that this was GasNet's intention and raised the apparent anomaly with GasNet.

Consequently, GasNet proposes to amend the definition of Insurance Event to only cover circumstances in which GasNet is required to pay a deductible in connection with a claim under an insurance policy. GasNet also proposes to remove the definition of Minimum Insurance Level as it is not referred to elsewhere in the proposed AA. The ACCC supports GasNet's proposal.

In contrast, the ACCC proposes not to approve GasNet's proposed pass through of an asbestos event as this would act as a disincentive for GasNet to manage this risk. If

GasNet is unable to insure against this risk, the ACCC will consider any substantiated proposal for self-insurance.

Volumes

GasNet proposes annual and peak volume forecasts which match the medium economic growth scenario volume forecasts produced by VENCorp for its 2006 Gas Annual Planning Report (GAPR). The ACCC has paid particular attention to GasNet's anytime withdrawal volume forecasts because under GasNet's proposed average revenue yield approach, total revenue outcomes are only sensitive to these initial anytime withdrawal volume forecasts. The ACCC has also considered annual injection, peak injection and peak withdrawal volume forecasts as these forecasts influence tariffs to end-users.

The ACCC notes that GasNet's proposed anytime withdrawal volume forecasts for AA3 are about 20 PJ or 2 per cent less than for proposals for AA2. The ACCC has found that lower gas power generation (GPG) forecasts of gas usage proposed for the AA3 period, compared to the AA2 period contribute more than 2 per cent to the difference between periods. The ACCC has re-assessed the GPG forecasts noting in part that effects of the drought on the electricity market impacting on generator dispatch became more apparent in early 2007, after the 2006 GAPR was published. Having re-assessed GPG forecasts, the ACCC proposes amendments to increase forecast GPG volume by 8 PJ over the period. Even with these revisions, GasNet's withdrawal volume forecasts for the AA3 period will still be less than for the AA2 period. However, the ACCC considers that the lower withdrawal forecasts for this period are likely to reflect a better assessment of the impact of weather warming and its downwards effect on gas usage in Victoria generally, than was appreciated for the AA2 period.

The ACCC notes GasNet has experienced volatility in volume outcomes during the AA2 period, highlighted in 2005 by an 11.4 per cent volumes shortfall against allowed volumes. In the context of being a largely fixed-cost business, GasNet proposes a revised price control to limit its exposure to the risk of actual volumes being higher or lower than forecast volumes. The ACCC considers this revised form of price control is consistent with the requirements of the code and preserves an incentive to maintain and promote the system to develop the market (refer below where this is considered in more detail).

The ACCC has assessed injection volume forecasts. The ACCC has considered the basis for GasNet's increased forecasts of injections from Otway Basin as reasonable based on the commissioning of the Otway gas plant in September 2007 and the completion of the Corio loop before winter 2008, which make available more gas flow from the Otway Basin. However, the ACCC has decided to reserve its final decision on injection forecasts in order to enable the ACCC and users a further opportunity to comment on injection volume forecasts with better information as to:

- the requirement that GasNet provide top ten peak day volumes for charging and maintain direct asset group cost allocation for injection zones. The ACCC notes this will increase the impact of volume forecasts on injection tariffs in contrast to GasNet's proposed approach and
- the early Otway gas plant production in competition with other Gippsland/Otway processing facilities as well as latest information on the Corio loop project.

The ACCC has also audited peak and annual volume forecasts within GasNet's cost allocation models and requires GasNet to make amendments to ensure consistency with GasNet's proposed approach of charging end-users on a basis that represents an allocation of costs reflective of relative contributions to peak and annual usage of the system.

Revenue requirement

GasNet's proposed revenue requirement is summarised in table A.6:

Table A.6: Proposal—revenue requirement

$2006 Dec m	*2008*	*2009*	*2010*	*2011*	*2012*
Return on capital	32.42	37.63	41.86	42.42	42.43
Depreciation	22.53	25.79	28.09	28.58	29.40
Non-capital costs	27.37	26.25	26.03	27.59	29.40
Total revenue requirement	**82.30**	**89.68**	**95.98**	**98.59**	**101.23**
Forecast revenue	**86.18**	**89.77**	**93.79**	**96.87**	**100.55**

GasNet's proposed revenue calculation is based on an assumption that capital expenditure is recognised in the middle of each year, in contrast to the end of the year as per the current arrangements. This results in depreciation and return on capital being calculated for an additional six months in the year capex is recognised. GasNet states that this change is consistent with the approach used elsewhere by the ACCC and the AER, and that the continuation of the current approach, where capex is assumed to occur at the end of the year, would result in an under-recovery of costs over the AA3 period. GasNet submitted an illustrative monthly model which it argues demonstrates the extent of this under-recovery.

The ACCC considers it appropriate to recognise GasNet's capex in the middle of each year as this broadly aligns with its commissioning dates. However, the ACCC also requires GasNet to apply present value adjustments to the opex and revenue values in its modelling to reflect the fact that these cash-flows occur evenly throughout the year. The method and data used to calculate these adjustments is contained in GasNet's monthly model. The ACCC estimates that these changes would result in GasNet over-recovering its costs by 1.6 per cent (in NPV terms) for the AA3 period, which is substantially less than the 4.3 per cent over-recovery that would result from continuing with the current timing assumptions in its proposal.

As a result of changes required in this draft decision, the ACCC's estimate of GasNet's revenue requirement is summarised in table A.7.

Table A.7: Draft decision—revenue requirement

$2006 Dec m	*2008*	*2009*	*2010*	*2011*	*2012*
Return on capital	35.58	36.70	36.61	35.54	34.46
Depreciation	22.73	23.97	24.28	24.11	24.20
Non-capital costs	24.36	20.95	20.86	21.61	23.03
PV revenue adjustment	–2.08	–2.06	–2.06	–2.05	–2.06
Total revenue requirement	**80.58**	**79.56**	**79.70**	**79.21**	**79.63**

Authorised MDQ and AMDQ credit certificate revenue

GasNet receives payments through the sale of authorised maximum daily quantity (AMDQ)/credit certificates to users of the PTS. GasNet's procurement and sale of AMDQ/credit certificates is governed by s. 5.3 of the MSO rules and its service envelope agreement (SEA) with VENCorp. AMDQ/credit certificates contracts are offered on a take or pay basis, whereby users pay for a specified contracted capacity. That is, if a user injects or withdraws less than the AMDQ/credit certificate amount, it is still liable to pay for the contracted amount. For usage in excess of the contracted AMDQ/credit certificate amount, users pay for the amount of the AMDQ/credit certificates and the excess is charged at the reference tariff. The ACCC notes that GasNet has the potential to recover additional revenue from issuing AMDQ/credit certificates where demand for AMDQ/credit certificates is likely to increase as a result of any future congestion on the PTS. Accordingly, the ACCC considers that where GasNet retains any additional revenue from AMDQ/credit certificates this may provide inappropriate incentives on GasNet as additional revenue is likely to be related to congestion on the PTS.

To deal with this potential over-recovery, the ACCC considers it appropriate that the amount of revenues received from AMDQ/credit certificates should be included in the 'actual revenues' referred to in cl. 4.2 of schedule 4 of GasNet's proposed AA, which would be counted towards its revenue requirement.

GasNet notes that the MSO rules do not mandate the issuance of AMDQ/credit certificates and that the ACCC's proposed treatment would remove any incentive for it to issue AMDQ and AMDQ credit certificates. Given the ACCC views AMDQ and AMDQ credit certificates as beneficial for market participants, it intends to allow GasNet to propose any additional operating costs associated with issuing and administering these authorised MDQ and AMDQ credit certificates. Accordingly, the ACCC invites GasNet to propose any additional operating costs in response to the draft decision.

Cost allocation and tariff structures

GasNet proposes to change the allocation of direct costs to both withdrawal and injection assets. GasNet submits that in the short term, the new tariff model is likely to lead to lower tariffs than under the current tariff model for some users and higher tariffs for other users. However, GasNet submits that over the longer term it expects this to even out. GasNet comments that any short term adverse consequences will be outweighed by the other benefits, namely increased simplicity, predictability, robustness and price stability, and the positive impact on retail competition.

In its final decision for AA2, the ACCC concluded that the tariff structure and cost allocation methodology proposed by GasNet, as modified by the ACCC's amendments, offered an appropriate balance to the (sometimes competing) requirements of the code. In assessing GasNet's current proposals, whilst a number of approaches may be considered appropriate, the ACCC notes that ss. 8.38 and 8.42 of the code require that tariffs reflect the costs of each service and each user 'to the maximum extent that is commercially and technically reasonable'. This requirement reflects certain aspects of the s. 8.1 objectives, in particular s. 8.1(d) of the code which specifies the reference tariff should not distort investment decisions in pipelines. Other considerations such as simplicity, predictability, robustness and price stability, and the positive impact on retail competition are only applicable indirectly in the way they contribute to the s. 8.1 objectives and are thus of limited relevance to the issue of cost allocation. Accordingly, the ACCC does not consider these other factors in assessing GasNet's cost allocation methodology against the requirements of ss. 8.38 and 8.42 of the code. The ACCC also notes that whilst GasNet and some users have commented that GasNet's proposal will result in administratively simpler tariffs, no evidence has been provided to suggest that tariffs based on GasNet's current more cost-reflective methodology will be less commercially or technically feasible during the AA3 period. Two particular aspects of GasNet's tariff proposals are outlined below.

Postage stamp withdrawal tariff-V

GasNet proposes to apply a single rate for tariff-V (small) users across the PTS, so that all gas withdrawals from the PTS, which are allocated to tariff-V users will pay the same postage-stamp tariff. GasNet further notes that this approach will not materially detract from efficient pricing since retail prices are averaged across users anyway.

The ACCC notes that the effect of the postage stamp proposal for tariff-V is that a proportion of direct costs would be reallocated from northern zone and western zone users to metro and eastern zone users. As a result, the ACCC considers GasNet's proposed postage stamp rate for tariff-V customers is not consistent with ss. 8.38 and 8.42 of the code, which requires tariffs to be as cost reflective as possible. A benefit of cost reflective pricing is that it facilitates efficient usage and investment decisions by users. Consequently, it is appropriate for signals to be given to users (retailers) even if they do not pass them on to end users. Users may change their pricing behaviour in the future and pass on cost reflective tariffs. Irrespective of this, cost reflective pricing will give the appropriate basis for users (retailers) to make their own investment decisions, consistent with s. 8.1(d) of the code. The ACCC considers that while a single tariff-V would be simpler as GasNet and AGL maintain, the ACCC notes no evidence that complexity is an undue burden and also notes Origin Energy's observation that changing tariff structures also creates additional costs. Accordingly, the ACCC considers that a single postage stamp tariff for tariff-V customers is not consistent with the requirements of ss. 8.38, 8.42 and 8.1(d) of the code.

Injection tariff structure

GasNet proposes to charge the injection tariffs as a single flat rate over the peak period (being the winter months of June to September) instead of the basis of the existing ten day peak period. GasNet suggests that this will improve predictability and transparency, since injection tariffs will be known in advance. GasNet also suggest that the very high level of the current injection tariffs falls disproportionately on those injectors who provide the injections required to balance the PTS during the current ten day period.

At the time of the AA2 decision, the ACCC considered at some length the issue of introducing a peak injection tariff for the whole winter period. This issue was considered in response to submissions from stakeholders suggesting that injection charge be based on peak winter volumes, instead of the 10 peak days. The ACCC concluded that while this would reduce complexity faced by users, it would also reduce the effectiveness of the peak signalling.

Indeed, at the time of AA2, the ACCC considered GasNet's 10 day peak charge to be one of the advantages of its tariff structure. The 10 peak days not being known in advance gives users the incentive to modify their behaviour over the whole winter period in which the peak charges may arise. The ACCC concluded that 10 day peak charge requires users to pay in proportion to their contribution to the maximum capacity demanded from the system. This peak pricing structure provides incentives for best utilisation of pipeline infrastructure. To the extent that users avoid peak times, the pressure on system capacity (and enhancements) is diminished and efficient use of the assets is encouraged.

The ACCC considers that maintaining a peak injection tariff will provide tariffs that are efficient in level and structure and not distort investment decisions in accordance with ss. 8.1(e) and 8.1(d) of the code respectively. Consequently, the ACCC proposes not to approve GasNet's proposal to change its peak injection charge.

Reference tariff path

GasNet has proposed increased capex and opex coupled with lower volume forecasts. The recovery of these costs and the lower demand forecasts during the AA3 period implies a need for significant real increases in the average tariff over the AA3 period. GasNet proposes an initial average tariff of \$0.40/GJ (referred to as a P_0 change in table A.8) in 2008 increasing to \$0.45/GJ in 2012.

As a result of the ACCC's proposed amendments, GasNet's revenue requirement has been reduced and volume forecasts have increased. This has the effect of reducing the initial tariff increase in tariffs between 2007 and 2008 to approximately 16 per cent (or up to \$0.34/GJ), if GasNet maintains its proposed real increase of 2.8 per cent (X = –2.8) for the majority of its tariffs over the AA3 period, or 22.5 per cent (\$0.36/GJ) if a flat real tariff path (X = 0) over the AA3 period is adopted. These tariff impacts are outlined in the table A.8.

Table A.8: Initial and ongoing tariff movement

	Proposal	*Draft decision*	
X-factor	–2.8	–2.8	0.0
P_0 \$/GJ	0.40	0.34	0.36
% change between 2007 and 2008	36	16	22.5

Whilst, the step increase between the AA2 and AA3 periods remains significant despite the revised revenue requirement and volume forecasts, the ACCC notes that X = –2.8 per cent will result in the average tariff in 2008 being generally in line with the forecast price path based average tariff for 2007 of \$0.337. That is, in 2003 users would have expected an average tariff of around \$0.337/GJ in 2007 if volume mix forecasts in this period had been met. As noted above, the actual allowed average tariff for 2007 of \$0.295/GJ is the result of the balancing out of the higher average payments made by users earlier in the AA2 period. Accordingly, the ACCC does not consider the actual 2007 average tariff level indicative of the long term level.

An X-factor of zero may be appropriate if the average tariff in 2013 is likely to be around \$0.36/GJ (i.e. the forecast average tariff at the end of the AA3 period). If, however, the average tariff in 2013 is likely to be above \$0.38/GJ an X of –2.8 per cent may be more appropriate as this will more effectively manage the transition between AA2 and AA3 period as well as between AA3 and AA4 periods. Given the uncertainty surrounding expenditures and volumes for the AA4 period, the ACCC considers it more appropriate to minimise tariff shock between the AA2 and AA3 periods and to apply an increasing price path over the period (X = 2.8) for the majority of tariffs. The ACCC considers this will minimise price shock to users over future periods, whilst still allowing GasNet to recover its revenue.

Reference tariff variation policy

In brief, GasNet proposes a revised price control formula that:

- continues to limit GasNet's revenue risk to only anytime withdrawal volumes differing from forecast based on an average revenue yield under which GasNet bears no tariff mix risk
- removes its revenue volatility to coldness of weather (EDD outcomes)
- bounds actual volume variations from initial forecasts at 5.5 per cent, thereby capping the revenue risk/reward at 5.5 per cent and
- facilitates departures from a (CPI–X)(1+Y) side constraint, where Y =2%, if necessary to minimise revenue shortfalls against allowed revenue during the AA3 period.

The ACCC considers that GasNet's revised price control formula is symmetrical in terms of the revenue risk and reward that GasNet faces from actual volumes differing from forecast over AA3 period. The ACCC considers it is appropriate for a predominately fixed cost pipeline business to cap its revenue risk/reward at the volume bounds proposed and to also remove the effects of cold weather on the variability of its revenue as these factors are largely uncontrollable. The ACCC considers that GasNet forecasts of volumes, the effective degree days (i.e. the measure of coldness of weather) and the sensitivity of volumes to effective degree day are such that initial forecast volumes are unbiased, and as a result users and GasNet should share the same revenue risk/reward of actual volumes varying above or below forecast volumes.

The ACCC does not consider that GasNet should be allowed to relax its proposed side constraint on individual tariffs of 2 per cent above CPI–X based on a consideration of the requirements of ss. 8.1 and 2.24 of the code. GasNet's proposed relaxation of the side constraints on individual tariffs facilitates possible large tariff increases in the final year of the access period. The ACCC considers it is more appropriate for GasNet's general intra-period smoothing mechanism, facilitating tariff adjustments across remaining years, to be continued into the AA4 period. That is, if necessary any revenue under-recoveries (after CPI–X+2) during the AA3 period would be passed through into the AA4 period (and smoothed) as opposed to relaxing the constraint, which may facilitate tariff shock.

GasNet proposes to change its procedure for varying tariffs over the AA period. The ACCC considers that some of these proposed changes overlap with the code requirements or may provide inconsistencies between the AA and ss. 8.3B–8.3H of the code. The ACCC will discuss this issue with GasNet between the draft and final decision with a view to GasNet proposing an alternative approach.

Incentive mechanisms

GasNet proposes to amend its benefit sharing mechanism to require the regulator to use its discretion in applying negative carryover amounts based on the following grounds:

- the concern expressed by the ACCC, in approving the existing mechanism, overstates the ability of companies to alter the timing of their opex profiles
- if GasNet incurs higher cost while still being a prudent and efficient service provider, the expenditure allowance in the subsequent access period will be inappropriately reduced below its efficient level, which is inconsistent with s. 8.1(a) of the code
- other regulators have acknowledged that there may be circumstances in which negative carryover amounts could affect the entity's ability to provide efficient services and
- the use of discretion in applying negative carryover amounts, exercised in accordance with the code, is consistent with the approach used by the Essential Services Commission (Victoria) and the Essential Services Commission of South Australia.

In addition, GasNet proposes to require the regulator to use actual operating costs in 2011 as a basis for setting expenditure benchmarks for the AA4 period, rather than 'take into account' these actual costs as per the current arrangement. GasNet also proposes to remove fuel gas costs from the calculation of benefit sharing allowance.

The ACCC considers that the removal of fuel gas costs is consistent with the intent of the mechanism as these costs are largely uncontrollable by GasNet.

Regarding amendments to the operation of the mechanism, the ACCC notes that GasNet's current mechanism already places a considerable weight on the use of actual expenditures as a basis for assessing forecasts, in contrast to those of the ESC and ESCOSA. This has the effect of reinforcing the need to automatically apply positive and negative carryover amounts in order to preserve the incentive to minimise costs in each year in accordance with ss. 8.1(f) and 8.46(b) of the code. Furthermore, the ACCC considers that GasNet's proposal for the regulator to 'use' historic expenditure is inconsistent with other code requirements which may require the regulator to depart from or make adjustments to this amount.

Services policy

GasNet proposes a services policy on the basis that the status quo remains in terms of the arrangements between GasNet and VENCorp and users. The Victorian Government is in the process of amending the relevant legislative provisions to remove VENCorp's obligation to submit a revised AA under the code. As a consequence users will be required to enter into bilateral contracts for the gas transportation service with GasNet instead of VENCorp. Under these new arrangements, GasNet will provide gas transportation service directly to users as well as making the PTS available to VENCorp as required by the service envelope agreement (SEA).

As a result, the ACCC proposes that GasNet revise its services policy to reflect that GasNet rather than VENCorp has the direct legal relationship with users, and will provide gas transportation services directly to users.

Terms and conditions

The ACCC understands that GasNet proposes to include interim gas transportation deeds (GTDs) as part of its proposed AA, which will commence in January 2008 and expire in June 2008. The ACCC also understands that GasNet will re-negotiate long term GTDs with users, to take effect from July 2008. As these revised GTDs will form part of the terms and conditions on which GasNet will supply the reference service, the relevant regulator will need to approve these GTDs. To enable these revised GTDs to be assessed and approved, GasNet should include a trigger event for a revision of the AA in accordance with s. 3.17(b)(ii) of the code, where the trigger event would be a submission of revised GTDs to the relevant regulator for approval.

Accordingly, the ACCC requires GasNet as part of its AA to include GTDs (s. 3.6 of the code) and will review GasNet's interim GTDs prior to the final decision. Further, the ACCC proposes that GasNet consider the inclusion of a trigger event in its AA as a result of the requirement to re-negotiate GTDs with users during the AA period.

Extensions and expansions policy

The ACCC considers that GasNet's proposal that, on notice to the regulator, expansions increasing the capacity at Culcairn above 17 TJ/day would be uncovered should not be approved. The ACCC has considered the interests of users and the public interest in having competition in markets under the s. 2.24 of the code. The ACCC proposes a revision to the AA that any such expansion proposal above 17 TJ/day be subject to ACCC approval prior to project commencement, when detailed up to date information as to competing market forces (e.g. pipeline ownership, conditions on competing pipelines) can be considered. The ACCC considers that GasNet's continued proposal that when notice is provided, extensions will be uncovered, satisfies the requirements of the code.

1. Introduction

1.1 Access arrangement revisions

GasNet Australia Ltd is currently subject to an access arrangement (AA) which was approved by the Australian Competition and Consumer Commission (ACCC) in 2002 for the Principal Transmission System (PTS) in Victoria.[1] An AA describes the terms and conditions under which a service provider will make access to the services of the pipeline available to third parties. The AA2 period will end when the revisions approved by the ACCC come into effect.[2]

Chapter 2 of the *National Third Party Access Code for Natural Gas Pipeline Systems* (the code) specifies that the service provider of a gas pipeline covered by the code is required to propose revisions to an AA and submit them to the relevant regulator for approval by the revisions submission date.[3]

In assessing such proposed revisions to an AA, the code specifies that the relevant regulator must:

- inform interested parties that it has received the proposed revisions to the AA and the access arrangement information (AAI)
- publish a notice in a national daily newspaper which at least:
  - describes the covered pipeline to which the AA relates
  - states how copies of the documents may be obtained and
  - requests submissions by a date specified in the notice
- after considering submissions received, issue a draft decision that either proposes to approve the revisions or proposes not to approve the revisions and states the amendments (or nature of the amendments) that would have to be made to the revisions for the ACCC to approve them
- after issuing the draft decision, invite any further submissions
- 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 ACCC to approve them and
- if the amendments are satisfactorily incorporated in a revised AA, issue a further final decision (referred to as a final approval) to approve the revised AA.

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1 The Principal Transmission System is also commonly referred to as the GasNet system.

2 The current access arrangement period was scheduled to expire on 31 December 2007. On 31 October 2007 the ACCC extended the period for approving the revised access arrangement as permitted under s. 2.44 of the code.

3 In addition, a service provider may submit revisions at any time during the AA period. The assessment process for ‘voluntary’ revisions differs in a number of ways to that described.

If not, the ACCC must draft and approve its own AA addressing the specified amendments.

1.2 Consultative process

The code sets out a consultative process for the regulator to follow when assessing revisions to an AA.

On 30 April 2007 GasNet submitted to the ACCC its proposed revisions to the AA with accompanying AAI. These documents were made public via the Australian Energy Regulator (AER) website on 24 May 2007 and the public register held by the Code Registrar. After GasNet provided further supporting information, the ACCC published a notice in *The Australian* and released an issues paper on 24 May 2007 which both invited submissions from interested parties on the proposed revisions.

After considering submissions, the ACCC has now released its draft decision on 14 November 2007 which does not approve GasNet's revisions in their current form and proposes 32 amendments to be made to the revisions.

Interested parties are invited to make written submissions on this draft decision by 14 December 2007. After considering submissions, the ACCC will issue its final decision, which is scheduled for late February 2008. The public inquiry process is outlined below.

Submission of revised access arrangements	30 April 2007
Release of issues paper	28 May 2007
Due date for submissions on the issues paper	29 June 2007
Release of draft decision	14 November 2007
Due date for submissions on the draft decision	14 December 2007
Release of final decision	February 2008

All public submissions received will be placed on the AER website and the public register held by the Code Registrar. Any information considered to be confidential should clearly be marked as such and the reasons for seeking confidentiality provided. Under the code, the ACCC 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 users.

Submissions should be supplied in electronic format compatible with Microsoft Word to the email address gns@accc.gov.au. One original signed document should also be mailed to the postal address:

Mr Chris Pattas
General Manager
Network Regulation South
Australian Competition and Consumer Commission
GPO Box 520
Melbourne VIC 3001

Copies of the revisions application and associated documents are available (subject to confidentiality restrictions) from the AER website and from the Code Registrar. Copies of this draft decision may also be obtained from the ACCC by contacting Mr Blair Burkitt on telephone (03) 9290 1442 or Ms Maria Djopa on telephone (03) 9290 1436; facsimile (03) 9290 1457; or email gns@accc.gov.au.

1.3 Criteria for assessing revisions to access arrangements

The regulator may approve revisions to an AA only if it is satisfied that the AA as revised would contain the elements and satisfy the principles set out in ss. 3.1–3.20 of the code, which are summarised below. Revisions to an AA cannot be opposed solely because the AA as revised would not address a matter that s. 3 of the code does not require it to address. Subject to this, the relevant regulator has a broad discretion in accepting or opposing revisions to an AA.

An AA, or a revised AA, 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 reference tariff. Tariffs must be determined according to the reference tariff principles in s. 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.

In considering whether a revised AA complies with the code, the ACCC must take into account the provisions of the AA as it currently stands and, pursuant to s. 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 ACCC considers are relevant.

Appendix B of this draft decision sets out the AAI that a service provider must disclose to interested parties (attachment A to the code).

1.4 The previous access arrangement assessment

The previous AA process was conducted in accordance with the requirements set out in the code and was based on information provided by GasNet and interested parties. All ACCC decision documents are available on the AER website**.**

GasNet submitted a proposed revised AA to the ACCC for the AA2 period for approval on 28 March 2002. The ensuing consultation and assessment process undertaken by the ACCC included:

- the release of the draft decision (under s. 2.13 of the code) on the proposed AA on 14 August 2002, in which the ACCC set out 35 proposed amendments to be made for the AA to be approved
- the release of the final decision (under s. 2.16 of the code) on 13 November 2002, with the ACCC set out 45 amendments to be made for the AA to be approved
- the release of a further final decision (under s. 2.19 of the code) in which, the ACCC, pursuant to s. 2.41(c) of the code, did not approve the revised AA submitted by GasNet on 6 December 2002 and 6 January 2003 and
- the release of the revised AA approved and drafted by the ACCC for GasNet (under s. 2.42 of the code).

GasNet subsequently lodged a merits review application with the Australian Competition Tribunal (Tribunal). On 23 December 2003 GasNet’s AA was revised by order of the Tribunal. The Tribunal’s orders and the revised AAs are available on the AER’s website.

On 24 August 2004 GasNet proposed four separate revisions to its AA. The ACCC approved three of the four proposed revisions and the decision documents on 15 December 2004. Further, on 24 December 2005 GasNet provided an application under s. 8.21 of the code seeking an upfront binding approval from the ACCC that construction of the Corio loop satisfied the requirements of s. 8.16 of the code. On 6 June 2006 the ACCC published a final decision which approved the Corio loop under s. 8.21 of the code.

1.5 Regulatory framework

This assessment of the revised AA is subject to the code. Any subsequent scheduled revisions will be assessed under the National Gas Law and National Gas Rules to be introduced in 2008.

1.5.1 Relevant legislation

The main legislation and relevant documents regulating access to the PTS are:

- the code, under which transmission service providers are required to submit AAs and revised AA to the ACCC for approval
- the Market and System Operations Rules (MSO rules) and
- the *Gas Pipelines Access (South Australia) Act 1997*.

In accordance with the Natural Gas Pipelines Access Agreement, South Australia was the lead legislator in implementing the national gas access legislation.

1.5.2 Regulatory institutions

Code and appeals bodies for the PTS are:

- The ACCC—the regulator and the arbitrator.
- The National Competition Council (NCC)—the code advisory body.
- The Commonwealth Minister—the coverage decision maker.
- The Federal Court of Australia—judicial review.
- The Australian Competition Tribunal (Tribunal)—merits review.

1.5.3 The role of the AER

The ACCC has prepared this draft decision with the assistance of the AER.[4] The ACCC currently regulates natural gas transmission pipelines under the code except in Western Australia. However, governments have agreed that the regulation of natural gas transmission pipelines, along with natural gas distribution pipelines, will be undertaken by the AER from 2008.

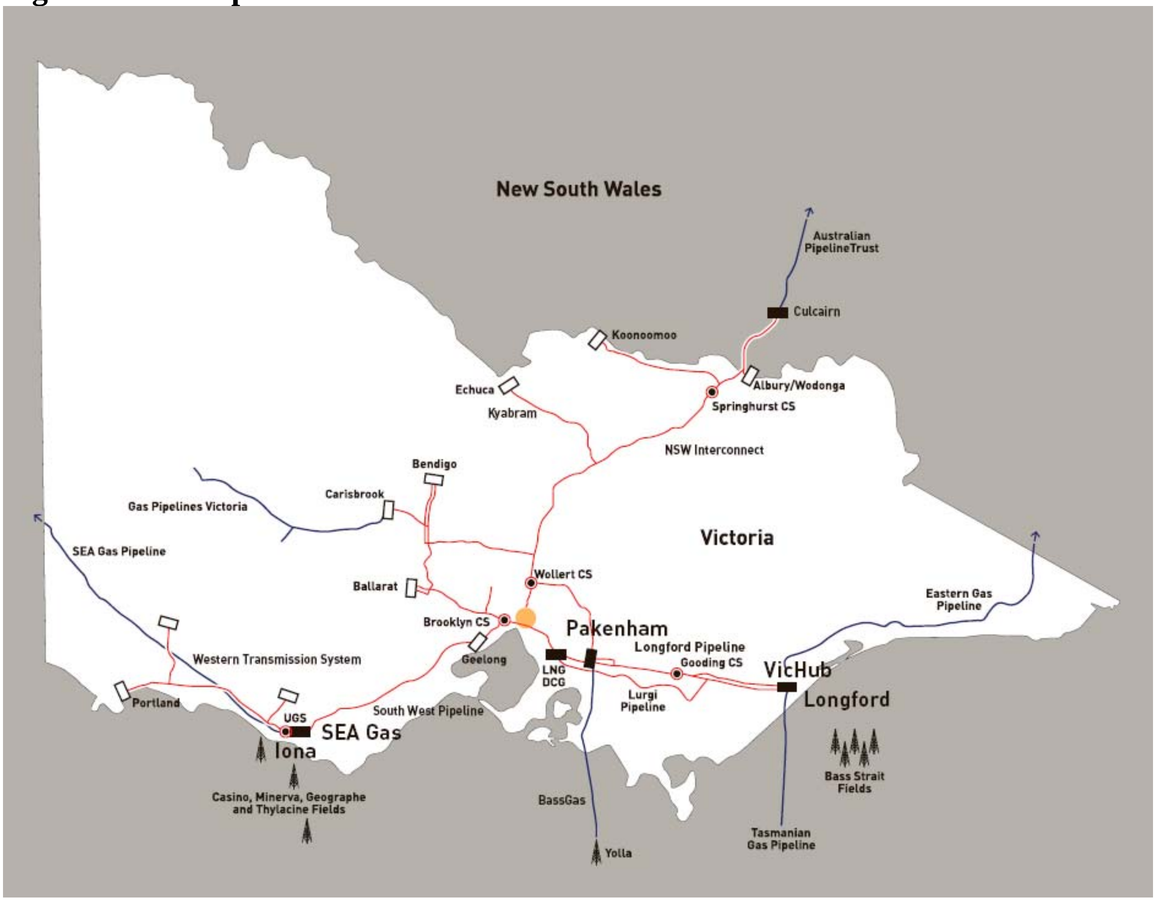
4 The relevant regulator of the code with respect to the PTS is the ACCC. All references in this draft decision to the relevant regulator are to the ACCC. The AER will become the relevant regulator once proposed changes to legislation, which at the time of this draft decision remains under consideration, are enacted.

1.6 Background

1.6.1 The Principal Transmission System

The Principal Transmission System (PTS), also known as the GasNet system, is the primary system for the transmission of natural gas at high pressure in Victoria. GasNet is the owner of the PTS and VENCorp is the independent system operator of the PTS.

Figure 1.6.1: Map of the PTS



Source: VENCorp, *Gas Annual Planning Report 2006*.

For the purpose of tariff recovery, the PTS comprises of gas injection pipeline assets and gas withdrawal pipeline assets. Injection tariffs are charged for the costs attached to usage of injection pipeline assets. Withdrawal tariffs recover the costs attached to usage of the system for transmission of gas from injection pipelines to users, i.e. primarily those costs incurred in the usage of withdrawal pipelines. In some tariff zones, users receive a discount for withdrawing off an injection pipeline prior to the gas using all the pipeline.

The PTS is not a traditional point to point transmission pipeline as there are a number of injection points. As set out in GasNet's submission, the PTS has the following five main injection zones:

- Longford, comprising injection points at the site of the ESSO/BHP Billiton processing facility; VicHub (the interconnection with the Eastern Gas pipeline)

- Culcairn, the NSW interconnection with the Moomba-Sydney gas pipeline system
- Port Campbell, comprising the injection point for the Western Underground Gas Storage facility and local fields
- an interconnection with the SEA Gas pipeline and Minerva processing facility
- Dandenong, the site of the LNG facility and
- Pakenham injections, for gas sourced from the Yolla gas field.

Since the start of AA2 there has been an increase in the number of injection points. This coincides with an observable reduction in the reliance on Longford injections and the development of new gas fields and new gas production facilities. Table 1.6.1 sets out the change in gas sources for the PTS between 2003–06.

Table 1.6.1: Gas sources for the PTS

PJ %	*Source of gas supply*						
	Longford		BassGas[a]	Port Campbell		Culcairn	Dandenong LNG Facility
	Longford	VicHub		Iona	SEA Gas		
Annual							
Sep 02–Sep 03	89.9	4.3	n/a	5.8	n/a	–0.2[c]	0.1
Sep 05–Sep 06	84.0	4.4	1.4	5.8	3.5	0.9	0.1
Peak							
2003	79.24		0.0	14.35		2.29	4.12
2007(d)	76.60		5.3	15.77		0.0	2.32

Source: VENCorp, *Gas Annual Planning Report 2006*, section 2.4; VENCorp, *Gas Annual Planning Report 2004*, p. 13.

a BassGas was commissioned in June 2006.

b SEA Gas was commissioned in January 2004.

c The negative injection percentage reveals a greater amount of gas withdrawn (exported) from the PTS than injected into the PTS from the connected Moomba to Sydney Pipeline.

d Coincident system peak day volume up to end June 2007.

Whilst Longford injections remain the primary source of gas, supplies from other sources are increasing over time. GasNet forecasts this trend of gas supply, which places less reliance on the Longford injection zone, to continue in AA3.

Gas injected into the PTS is primarily delivered into Victoria's gas distribution system, however, some large customers are directly connected to the transmission network. A small amount of gas injected into the PTS is exported out of the system to:

- the separately owned Carisbrook to Horsham pipeline transmission pipeline in Victoria
- South Australia via the SEA Gas pipeline and
- NSW via Culcairn and the VicHub.

The PTS provides, along with distribution pipelines, a large part of the infrastructure necessary to facilitate both wholesale and retail competition in natural gas. As table 1.6.1 details, gas is increasingly sourced from a variety of fields. Diversity of ownership within these fields has been increasing along with the diversity of retail offerings to customers. The ACCC's final decision and access pricing decisions on the PTS must be sensitive to potential impacts on competition in both the wholesale and retail gas market.

1.6.2 Allocation of responsibilities between GasNet and VENCorp

Under the code, both GasNet and VENCorp were service providers during the AA1 and AA2 periods. Their AAs allocate responsibility between them for complying with the obligations imposed by the code.

Under the market carriage capacity management system operating in Victoria, users currently pay tariffs to both the system owner, GasNet, and the independent system operator, VENCorp. As the owner of the PTS, GasNet is responsible for the extensions and expansions policy in accordance with s. 3.16 of the code and VENCorp is responsible for the queuing policy in accordance with ss. 3.12–3.15 of the code. VENCorp's obligations in respect of queuing are contained in the MSO rules under the *Gas Industry Act 2001* (Vic).

The Victorian Government has accepted the recommendations of a statutory review of VENCorp's functions that VENCorp no longer be required to submit an AA under the national gas access regime. In its place, the review recommended VENCorp's costs and revenues be regulated on an annual basis by the AER under explicit provisions in the National Gas Law when it is enacted.

Under the Victorian Government's proposals, VENCorp's obligations in respect of the queuing policy for the PTS will remain under the MSO rules. It is expected that the rule making functions in respect of the MSO rules will transfer to the Australian Energy Market Commission.

Under the existing regulatory arrangements, GasNet makes the PTS available to allow VENCorp to operate the pipeline. VENCorp has a direct relationship and enters into gas transportation deeds with the users of the PTS. The Victorian Minister for Energy has indicated that if necessary legislation will be introduced so VENCorp is no longer an intermediary between GasNet and the users of GasNet's transportation service. Instead, there will be a direct contractual relationship between GasNet and users.

VENCorp requested an extension of its revisions submissions date on the basis that the AER will approve the costs and revenues of VENCorp's reference services under the new regulatory arrangements. The ACCC approved this extension request on 28 March 2007. Accordingly, this draft decision only covers GasNet's proposed revisions and the processes for approving the revised AA.

2. Reference tariff method

This chapter examines the basis on which GasNet's proposed reference tariffs are established and references the relevant chapters of this draft decision.

2.1 Reference tariff policy

2.1.1 Code requirements

Section 3.5 of the code requires an access arrangement (AA) to include a policy which describes the principles that are to be used to determine a reference tariff. This reference tariff policy must, in the relevant regulator's opinion, comply with the general reference tariff principles set out in s. 8.1 of the code.

Section 8.1 of the code states that a reference tariff and a reference tariff policy should be designed with a view to achieving the following objectives:

> (a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering the Service
>
> (b) replicating the outcome of a competitive market
>
> (c) ensuring the safe and reliable operation of the Pipeline
>
> (d) not distorting investment decisions in Pipeline transportation systems 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.

The code acknowledges that these objectives may conflict. The relevant regulator may determine how the objectives should be reconciled or which should prevail. Section 8.2 of the code sets out the factors which the regulator must be satisfied of in determining to approve a reference tariff and reference tariff policy. These are:

> (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 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 the 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.

2.1.2 Proposal

Clause 4.3 of the proposed AA sets out a policy that describes the principles that are used to determine the proposed reference tariffs. This reference tariff policy describes the methodology used in deriving the reference tariff and the structure of the reference tariffs. It also sets out the information about the treatment of new facilities investment and redundant capital and describes the proposed incentive mechanism.

2.1.3 Submissions

No submissions were received on this aspect of the proposed AA.

2.1.4 Assessment

As required under s. 3.5 of the code, GasNet has included a reference tariff policy in the proposed AA. The ACCC's assessment of each element of the reference tariff policy is provided in the relevant chapters of this draft decision.

2.2 Reference tariff methodology

2.2.1 Code requirements

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 reference tariffs and the reference tariff policy can be approved. The general principles are set out in ss. 8.1 and 8.2 of the code.

Section 8.3 of the code states that, subject to requirements of that section and the s. 8.1 objectives, the method by which the reference tariff may vary within an AA period through implementation of the reference tariff policy is within the discretion of the service provider.

Section 8.3 of the code sets out examples of variation methods a service provider may select from:

> (a) the Cost of Service Approach[5]—where tariffs are adjusted throughout the access arrangement period to account for actual outcomes (such as sales volumes and actual costs) to ensure that the actual costs of the services are recovered;
>
> (b) the Price Path Approach—where tariffs are determined prior to the commencement of 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;
>
> (c) the Reference Tariff Control Formula Approach—where tariffs may vary over the access arrangement period in accordance with a specified formula or process;
>
> (d) the Trigger Event Adjustment Approach—where a reference tariff may vary within the access arrangement period following the occurrence of a specified event; or

[5] This approach is distinct from the cost of service approach detailed in s. 8.4 of the code, which refers to the methodology used to determine total revenue.

(e) any variation or combination of the above.

The selection of one of the above approaches is subject to s. 8.3A of the code and the relevant regulator being satisfied that the approach as implemented will be consistent with s. 8.1 of the code. Section 8.3A of the code states that a reference tariff may only vary during an AA period in accordance with an approved reference tariff variation method.

Section 8.4 of the code outlines the three methodologies available to the service provider to determine total revenue. The methodologies are:

(a) Cost of Service: where the total revenue is set to recover costs with those costs to be calculated on the basis of a return (rate of return) on the value of the assets that form the covered pipeline (capital base), depreciation of the capital base (depreciation) and the operating, maintenance and other non-capital costs (non-capital costs) incurred in delivering all services;

(b) Internal Rate of Return (IRR): where the total revenue is set to provide an acceptable IRR (consistent with s. 8.30 and s. 8.31 of the code) for the covered pipeline on the basis of forecast costs and revenue; and

(c) Net Present Value (NPV): where the total revenue is set to deliver a NPV for the covered pipeline (on the basis of forecast costs and revenue) equal to zero, using an acceptable discount rate (consistent with s. 8.30 and s. 8.31 of the code).

These methodologies are different ways of assessing total revenue, however, the outcomes should be consistent (for example, it is possible to express any NPV or IRR calculation in terms of a cost of service calculation by the choice of an appropriate depreciation schedule).

Regardless of which method is adopted, the method should be utilised in accordance with generally accepted industry practice. In addition, other methodologies that can be translated into one of these forms are acceptable under s. 8.5 of the code.

Section 8.5A of the code allows the above methodologies to be applied on a nominal basis, a real basis or any basis dealing with the effects of inflation, provided that the basis used is specified in the AA and is applied consistently in determining the total revenue and the reference tariffs.

2.2.2 Current access arrangements provisions

GasNet has adopted the cost of service approach, which applies a building block methodology, for the AA2 period to determine the total revenue requirement.

Under the second AA, GasNet's tariffs vary in accordance with a price path approach. However, the inclusion of a pass-through mechanism, which allows GasNet to recover certain potential cost increases during the AA2 period, is consistent with a cost of service approach. GasNet's reference tariff methodology can be characterised as a combination of the price path and cost of service approaches.

2.2.3 Proposal

GasNet proposes to retain the cost of service approach to determine its total revenue requirement for the AA3 period.[6] That is, total revenue is calculated to recover the costs associated with the rate of return on assets that form the capital base, depreciation of that capital base and non-capital costs incurred in delivering services.[7]

To vary its reference tariffs during the AA3 period, GasNet proposes to apply a combination of a reference tariff control formula approach and a trigger event adjustment approach.[8]

In establishing the price path for the revised AA, GasNet has proposed that the initial reference tariffs at the commencement of the AA3 period be indexed in subsequent years by a CPI–X formula specified in cl. 4.1 of schedule 4 of the proposed AA. In addition to this annual adjustment, GasNet proposes that if there is a material change in new or existing taxes, insurance costs, regulatory costs, counterparty default, costs associated with a terrorism event or costs associated with an asbestos event, then this would be a specified event for the purposes of s. 8.3B of the code and the reference tariff may be adjusted by GasNet to pass-through such an amount to users.[9]

2.2.4 Submissions

No submissions were received on this aspect of the proposed AA.

2.2.5 Assessment

Section 8.4 of the code permits GasNet's retention of a cost of service approach to calculate its total revenue. However, the ACCC considers that this methodology has been incorrectly applied in the revenue model provided by GasNet to calculate its total revenue.[10]

GasNet proposes the reference tariff formula approach in accordance with s. 8.3(c) of the code, and to vary the reference tariff if a specified event occurs consistent with a trigger event adjustment approach in accordance with s. 8.3(d) of the code. A specified event includes a change in taxes, a regulatory event, an insurance event, a counterparty default event, a terrorism event or an asbestos event. Section 8.3(e) of the code permits the adoption of a combination of a price path, reference tariff control formula and trigger event adjustment approaches. As such, GasNet's approach is consistent with the code. GasNet's proposals are considered in detail in the following chapters.

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6 GasNet, *Access Arrangement Submission 2008–12*, 14 May 2007, p. 13.

7 ibid., p. 15.

8 ibid; GasNet's reference tariff control and trigger event adjustments are considered in chapter 6.3 of this draft decision.

9 ibid.

10 This is considered in chapter 5 of this draft decision.

3 Capital base

3.1 Roll forward of the capital base

This chapter considers the roll-forward of GasNet's capital base from the commencement of the second access arrangement (AA) period as approved by the ACCC in its 2002 final decision for AA2. The roll-forward calculation will determine the value of GasNet's capital base as at the beginning of the AA3 period and is a significant factor affecting the level of the reference tariffs. The return of capital (depreciation) and the return on capital are both dependent on the capital base and constitute most of the costs of delivering services.

3.1.1 Code requirements

Section 8.9 of the code states that (for the cost of service methodology) the capital base at the commencement of each AA period after the first is determined as:

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

3.1.2 Current access arrangement provisions

Clauses 4.4, 4.5 and 4.6 of GasNet's second AA are relevant to calculating the capital base.

GasNet's policy relating to capex approved during the AA2 period is set out in cls. 4.4 and 4.5 of its approved AA.

Clause 4.4 states reference tariffs have been determined on the basis of forecast capex in AA2 which is reasonably expected to satisfy the requirements of s. 8.16 of the code. Further, GasNet may submit at any time during the AA2 period revisions to increase the capital base to recognise further NFI which satisfies s. 8.16 of the code.

Clause 4.5 states GasNet may undertake NFI which does not satisfy the requirements of s. 8.16 of the code, referred to as 'speculative facilities'. If speculative investments are undertaken, in accordance with the code the recoverable portion (that which meets the requirements of s. 8.16 of the code) may be added to the capital base and the balance included in a speculative investment fund for possible future inclusion in the capital base.

Clause 4.6 allows the relevant regulator to adjust the capital base at the beginning of the AA3 period for assets that are wholly or partially redundant.

3.1.3 Proposal

GasNet states that the capital base as at 1 January 2003, as approved by the ACCC in its 2002 final decision for AA2, was $494.1 m.[11] GasNet has adjusted this value to reflect actual capital expenditure (capex) and inflation for 2002 which were not known at the time of the 2002 final decision for AA2. At that time, GasNet provided a best estimate of $0.66 m for capex in 2002 and as part of its current proposal indicates that actual capex for 2002 was $0.31 m. Similarly, an inflation estimate of 0.54 per cent for the 2002 December quarter was used for the 2002 final decision for AA2, whereas actual inflation for this quarter was 0.72 per cent. After correcting for these estimates, GasNet calculates its capital base to be $496.18 m.

Table 3.1.1 illustrates GasNet's adjustments to the capital base for depreciation, inflation and capital expenditure since 1 January 2003 to give a capital base at 1 January 2008 of $524.36 m.[12]

Table 3.1.1: Proposal—roll-forward of the capital base

nominal $ m	*2003*	*2004*	*2005*	*2006*	*2007*
Opening capital base	**496.18**	**487.97**	**479.70**	**473.88**	**485.73**
Depreciation allowance	–20.61	–21.60	–22.81	–23.92	–24.41
Capital expenditure	0.50	0.70	3.62	20.69	48.08
Disposals/redundancies	0.00	0.02	0.00	0.00	0.00
Inflation	11.90	12.64	13.37	15.08	14.97
Closing capital base	**487.97**	**479.70**	**473.88**	**485.73**	**524.36**

Source: GasNet, *AAI 2008–12*, p. 3; data from GasNet RAB model and PTRM.

GasNet proposes that its actual capex be included in the capital base on an 'as-commissioned' basis, which does not recognise the timing or value of actual expenditures incurred prior to capitalisation. In this context GasNet also proposes to capitalise the costs of interest during construction (IDC) for each asset constructed during the AA2 period (as well as the proposed forecast capex for the AA3 period). In calculating IDC amounts, GasNet has modelled monthly expenditure profiles for four types of assets. Expenditure on pipelines, compressors, pressure regulators and heaters is assumed to occur over a 22 month period with commissioning occurring at the end of the 19th month. Expenditure on 'other' assets is assumed to occur over three months with commissioning at the end of the third month.

GasNet notes that the Brooklyn Lara pipeline (the 'Corio loop' augmentation) will be commissioned in 2008. Under an as-commissioned approach, GasNet proposes to recognise this project as forecast capex for the AA3 period.[13]

Subsequent to lodging its proposed revisions, GasNet has provided a revised cost estimate for the Corio loop project, amounting to $69 m, compared to the $63.7 m approved by the ACCC in 2006.[14]

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11 GasNet, *Proposed Access Arrangement Submission 2008–12*, 14 May 2007, p. 18.

12 id., *Proposed Access Arrangement Information 2008–12*, 14 May 2007, p. 3; ibid., p. 17.

13 id., *Submission*, op. cit., p. 53.

3.1.4 Submissions

Origin Energy was concerned that the inclusion of IDC would place no incentives on GasNet to be efficient and that assessment of benchmark expenditure profiles would be difficult for the ACCC.[15] It also noted that allowing GasNet to claim IDC could have flow on effects for other regulatory determinations.[16]

3.1.5 Assessment

3.1.5.1 Corrections for 2002 forecasts

In calculating its capital base at the beginning of the AA2 period, GasNet provided a best estimate of $0.66 m for capex in 2002, whereas actual capex during 2002 was $0.31 m. While GasNet has used the actual capex amount in calculating its capital base, the higher forecast capex amount was incorporated into the capital base for the AA2 period and GasNet has therefore earned a return on and of this amount over the period. As set out in table 3.1.2, the return on the value of this overestimate that was earned by GasNet over the AA2 period is $6.91 m. GasNet does not propose to pass back the value of the return on this underspend to network users through a reduction in its revenue requirement for the AA3 period.

Table 3.1.2: Return on capital from overestimate of 2002 capex

nominal $ m	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*Total*
Value of overestimate	0.35						
Associated return on capital		0.03	0.42	0.87	1.81	3.79	6.91

Source: ACCC estimates, based on a nominal WACC of 8.93 per cent.

The ACCC considers that allowing service providers to retain the benefit of such overestimates (or to be penalised where returns on actual capex above the estimate are not provided) would create an incentive to overestimate capex in the final year(s) of an AA period when actual values cannot be known due to the timing of access reviews. Such a time constraint has, for example, required GasNet to provide estimates of capex for 2007 as part of this review. The values provided for these final years are intended to be best estimates of actual expenditure for the purposes of valuing the capital base under s. 8.9(b) of the code, and not benchmarks of prudent and efficient expenditure to be outperformed by service providers. The ACCC considers that the benefit of the return on this overestimate for 2002 should be taken back from GasNet and passed onto network users in the form of a reduction to its opening capital base for the AA3 period.

The return of capital associated with this overestimate was provided to GasNet in the depreciation allowance for AA2, which has been deducted from the opening capital base for AA3. The ACCC considers that GasNet has already earned this depreciation

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14 id., *Email to the AER*, 22 October 2007.

15 Origin Energy, *Submission to the issues paper*, 9 July 2007, p. 8.

16 ibid.

allowance and its proposal to deduct this amount from its capital base is in accordance with ss. 8.9(c) and 8.33(d) of the code.

GasNet used an inflation estimate of 0.54 per cent for the December quarter 2002 in calculating its capital base as at the beginning of the AA2 period. GasNet has adjusted the capital base to incorporate actual inflation for this period of 0.72 per cent. In effect, this underestimate of inflation resulted in GasNet’s capital base being slightly undervalued for the AA2 period, resulting in the returns on capital and depreciation being lower than they would otherwise have been. The value of these foregone returns is illustrated in table 3.1.3.

Table 3.1.3: Foregone returns on capital and depreciation from inflation underestimate

nominal $	*2003*	*2004*	*2005*	*2006*	*2007*	*Total*
Return on capital	63 408	65 045	66 822	68 962	71 062	335 299
Depreciation	73	75	77	56	58	340

Source: ACCC estimates.

The ACCC considers that the foregone return on capital over the AA2 period is not material (amounting to less than 0.1 per cent of total revenue) although represents revenues that would have been earned by a prudent service provider. Accordingly, this return on capital should be recovered through regulated tariffs and added to GasNet’s opening capital base for the AA3 period. The amount of foregone depreciation has not been deducted from GasNet’s capital base over the AA2 period thus GasNet has incurred no penalty that requires corresponding compensation.

3.1.5.2 Interest during construction

GasNet calculates IDC as the amount of additional expenditure that would equate, in present value terms, the value of the assumed monthly expenditures over the construction period and the total cost of the asset at commissioning date. In other words, the cost of financing each project is assumed to accrue on the balance of monthly expenditures at the rate of GasNet’s proposed weighted average cost of capital. GasNet assumes that all assets are constructed according to four types of cash-flow profiles (i.e. pipelines, regulators/ heaters, compressors and other).

The ACCC has considered the comments made by Origin Energy regarding the precedent of accepting these costs for other regulated assets. The same concerns were raised in consultation on GasNet’s Corio loop augmentation, where the ACCC found these costs to be appropriate.[17] The ACCC has also recognised IDC costs in reviews of the Victorian AAs, the Amadeus Basin to Darwin pipeline and the Central West pipeline AAs.[18] The ACCC maintains the view that the principles set

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17 ACCC, *Final Decision: GasNet Australia Major System Augmentation—Corio loop*, 6 June 2006, pp. 26–8.

18 id., *Victorian Gas Transmission Access Arrangements: Final Decision*, 6 October 1998, pp. 27, 101–3; id., *Central West Pipeline Access Arrangement: Final Decision*, June 2000, pp. 58, 64; fn. 121; id., *Amadeus Basin to Darwin Pipeline Access Arrangement: Final Decision*, 4 December 2002, p. 30.

out in ss. 2.24 and 8.1 of the code would not be satisfied if GasNet were unable to recover sufficient revenue to meet these costs. In this context it considers that the provision of an allowance to meet IDC costs incurred in constructing new facilities is in the long-term interests of users and prospective users consistent with s. 2.24(f) of the code.

In response to Origin Energy's comments on the incentive effects and assessment of benchmark expenditure profiles, the ACCC has examined the profiles submitted by GasNet and does not consider them to be unreasonable. In particular the profile used for pipelines presented by GasNet as part of this review is similar to that accepted by the ACCC in its assessment of the Corio loop augmentation.

3.1.5.3 Corio loop augmentation

In agreeing to the Corio loop augmentation in accordance with s. 8.21 of the code, the ACCC proposed to treat separately expenditure incurred on that project between the AA2 and AA3 periods.[19] Expenditure incurred (including IDC) to 31 December 2007 was to be capitalised and added to GasNet's opening capital base at 1 January 2008. IDC was to be calculated on the monthly actual costs using the nominal vanilla WACC of 6.62 per cent approved for the AA2 period. For the AA3 period, the ACCC would recognise the approved $61.7 m less the actual expenditure in AA2 as forecast NFI, as well as IDC on that amount until the commissioning date of 31 March 2008.

The ACCC's proposed treatment relates to s. 8.20 of the code, which allows reference tariffs for a particular access period to be based on expenditure that is forecast to occur in that period. The ACCC notes that a substantial proportion of expenditure on the Corio loop augmentation has occurred in the AA2 period. The inclusion of this proportion in the closing capital base for the AA2 period under s. 8.15 of the code (which allows the capital base to be increased to recognise actual capex) and the assessment of the remaining expenditure that is forecast to occur during the AA3 period under s. 8.20 of the code is more consistent with the requirements of the code than GasNet's proposal.

Accordingly, the ACCC requires GasNet to capitalise actual (or a best estimate of) expenditure incurred on the Corio loop augmentation to 31 December 2007, including IDC, when calculating its capital base and forecast expenditures for the AA3 period.

The ACCC has not had adequate time to assess GasNet's revised cost estimate for this project, and will do so as part of its final decision. For this draft decision, the ACCC has relied on the amount approved in June 2006 of $63.7 m. GasNet has provided a best estimate of expenditure on this project for the AA2 period of $45.51 m ($ December 2006) and IDC of $1.19 m. From this data, the ACCC

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19 id., *Final Decision: Corio loop*, op. cit., p. 47.

estimates that the remaining or forecast capital cost of the approved amount is $18.19 m[20] and associated IDC is $0.48 m.

3.1.6 Conclusion

As a result of the amendments to GasNet's capital base considered above, the roll-forward calculation differs from that proposed. The ACCC has amended GasNet's modelling to provide an indicative roll-forward calculation for the purposes of this draft decision. This indicative calculation is set out in table 3.1.4.

Table 3.1.4: Draft decision—roll-forward of the capital base

nominal $ m	*2003*	*2004*	*2005*	*2006*	*2007*
Opening capital base[a]	**496.18**	**487.97**	**479.70**	**473.88**	**485.73**
Depreciation allowance	–20.61	–21.60	–22.81	–23.92	–24.41
Capital expenditure[b]	0.50	0.70	3.57	20.36	94.77[c]
Disposals/redundancies	0.00	(0.02)	0.00	0.00	0.00
Inflation	11.74	12.64	13.43	15.42	15.01
Closing capital base	**487.80**	**479.69**	**473.89**	**485.74**	**571.09**
Adjustment for 2002 capex overestimate					–6.91
Adjustment for 2002 inflation underestimate					0.34
Adjusted closing capital base					**564.51**

Source: ACCC analysis.

[a] A minor discrepancy exists between GasNet's model and this summary roll-forward calculation.

[b] Includes IDC.

[c] Includes expenditure associated with the Corio loop augmentation.

Proposed amendment 01

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 2.1 of its proposed revised access arrangement information to reflect table 3.1.4 of this draft decision.

[20] The initial approved amount ($61.70 m) expressed in 2006 dollars of $63.70 m, less $45.51 m incurred in the AA2 period.

3.2 New facilities investment

3.2.1 Code requirements

Sections 8.15 and 8.16 of the code allow the capital base to be increased where additional capital costs are incurred in constructing or acquiring new facilities for the purpose of providing services. The first limb of s. 8.16 of the code, read in conjunction with s. 8.17 of the code, requires the relevant regulator first to be satisfied that the capex is prudent in terms of efficiency, in accordance with accepted good industry practice and is designed to achieve the lowest sustainable cost of delivering services.[21] The second limb requires the relevant regulator to also be satisfied that either:

- the anticipated incremental revenue exceeds the cost of the investment (the economic feasibility test) and/or
- the new facility either has system-wide benefits justifying higher tariffs for all users (the system-wide benefits test) and/or
- the new facility is necessary to maintain the safety, integrity or contracted capacity of services (the system integrity test).[22]

Under ss. 8.18 and 8.19 of the code an AA may state that a service provider may undertake new facilities investment if these criteria are not met. To the extent that an investment does not satisfy the criteria in s. 8.16 of the code or has a speculative element, the addition to the capital base is correspondingly reduced.[23]

3.2.2 Current access arrangement provisions

GasNet's policy relating to NFI approved during AA2 is set out in cls. 4.4 and 4.5 of the second AA.

Clause 4.4 states reference tariffs have been determined on the basis of forecast NFI in AA2 which is reasonably expected to pass the requirements of s. 8.16 of the code and that GasNet may submit at any time during the AA2 period revisions to increase the capital base to recognise further NFI which satisfies s. 8.16 of the code.

Clause 4.5 states GasNet may undertake NFI which does not satisfy the requirements of s. 8.16 of the code, referred to as 'speculative facilities'. If 'speculative investments' are undertaken, in accordance with the code the recoverable portion (that which meets the requirements of s. 8.16 of the code) may be added to the capital base and the balance included in a speculative investment fund for possible future inclusion in the capital base.

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21 Code, s. 8.16(a)(i).

22 Code, s. 8.16(a)(ii).

23 That portion of the investment which is of a speculative nature is held in the speculative investment fund and may be added to the asset base at a later date when it meets the criteria of s. 8.16 of the code.

3.2.3 Proposal

Clauses 4.4 and 4.5 of GasNet's proposed AA substantively reflect that approved by the ACCC for the AA2 period.

GasNet submits $32.16 m of actual capex incurred during the AA2 period, to be rolled-in to the capital base on the grounds that the requirements of the prudent investment test and the system integrity test have been satisfied.[24] This contrasts with the $47.72 m of forecast capex approved by the ACCC in 2002, which was reasonably expected to satisfy the requirements of the prudent investment test and the system integrity test.[25] Table 3.2.1 sets out the approved forecast capex against the actual capex GasNet incurred during the AA2 period.[26]

Table 3.2.1: Proposal—AA2 approved forecast capex

nominal $ m	*2003*	*2004*	*2005*	*2006*	*2007*	*Total*
Forecast						
Gooding compressor refurbishment	-	-	6.43	7.99	7.79	22.21
Lurgi pipeline refurbishment	2.04	2.09	1.54	-	-	5.67
City gate upgrades and heaters	-	3.45	2.50	3.26	-	9.21
Wollert compressor station automation	-	1.15	1.71	-	-	2.86
Gas chromatographs	0.92	-	-	-	-	0.92
Other maintenance capex	1.89	1.74	0.60	0.62	1.13	5.97
Total forecast capex	**4.85**	**8.43**	**12.77**	**11.87**	**8.91**	**46.84**
Actual						
Gooding compressor refurbishment	-	-	-	-	16.03	16.03
Lurgi pipeline refurbishment	-	-	-	2.82	-	2.82
City gate upgrades and heaters	-	-	-	-	5.38	5.38
Wollert compressor station automation	-	-	-	-	2.76	2.76
Gas chromatographs	0.27	0.19	-	-	-	0.46
Other maintenance capex	0.21	0.30	1.09	0.70	2.38	4.70
Total actual capex	**0.48**	**0.50**	**1.09**	**3.52**	**26.57**	**32.16**
Difference	**4.37**	**7.93**	**11.68**	**8.35**	**–17.66**	**14.68**

Source: GasNet, *Submission 2008–12*, tables 5.2 and 5.3.

Note these figures do not include interest during construction which is considered in chapter 3.1 of this draft decision.

GasNet also submits $35.42 m of other non-forecast capex was also incurred during the AA2 period.[27] In accordance with cl. 4.4 of the second AA, GasNet is allowed to

[24] ACCC, *Final Decision: GasNet Australia access arrangement revisions for the Principal Transmission System*, 13 November 2002, p. 183.

[25] GasNet, *Submission*, op. cit., pp. 20 and 21.

[26] The ACCC notes a slight discrepancy between the actual capex approved as reflected in the AAI as varied by the Australian Competition Tribunal in 2004 and that submitted to be approved by GasNet. c.f. GasNet, *Access arrangement information*, 1 January 2004, p. 12; and GasNet, *Submission*, op. cit., p. 20.

[27] ibid., p. 22.

submit revisions to the AA to increase the capital base to recognise further capex incurred which satisfies the requirements of s. 8.16 of the code. Table 3.2.2 sets out the non-forecast capex GasNet submits to have incurred during the AA2 period.

Table 3.2.2: Proposal—AA2 actual non-forecast capex

nominal $ m	*2003*	*2004*	*2005*	*2006*	*2007*	*Total*
Brooklyn compressor redevelopment	-	-	-	3.00	14.46	17.46
South Melbourne cut in	-	-	-	2.98	-	2.98
Wollert compressor station (miscellaneous)	-	0.17	0.83	-	1.15	2.15
Pig traps	-	-	-	-	0.72	0.72
Safety and security	-	-	-	-	0.79	0.79
Iona cooler upgrade	-	-	-	-	0.70	0.70
Regulators work	-	-	-	-	0.42	0.42
Maximo	-	-	1.37	-	-	1.37
Corporate restructuring	-	-	-	8.84	-	8.84
Total non-forecast capex	**0.00**	**0.17**	**2.20**	**14.82**	**18.23**	**35.42**

Source: GasNet, *Submission 2008–12*, p. 22.

GasNet submits all of the actual capex it has incurred was of a maintenance nature which did not increase or augment the capacity of the PTS and satisfies the requirements of the prudent investment test and the system integrity test.[28]

3.2.4 Submissions

TRUenergy does not agree with GasNet's proposal to recover the costs it incurred as a result of the acquisition of GasNet by the APA Group. TRUenergy submits that the costs should be borne by APA Group, the legal entity.[29] According to TRUenergy this is supported by Australian accounting standards that allow corporate restructuring costs to be capitalised as part of a company's acquisition costs and the APA Group should adopt this policy.[30]

TRUenergy has no objection to GasNet recovering the costs incurred internally to restructure GasNet that lead to long term efficiency benefits and lower gas transmission tariffs by capitalising such costs. It considers that the costs described by GasNet constitute acquisition costs rather than internal restructuring costs and therefore should not be recovered from users.[31]

The EUCV argues along similar lines and submits that the decision to acquire GasNet was made to benefit GasNet and APA shareholders rather than consumers. The EUCV notes that in the absence of the acquisition, there would not have been any transaction costs to recover. The EUCV questioned why consumers should be

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28 ibid., p. 24.

29 TRUenergy, *Submission to the issues paper*, 27 June 2007, p. 12.

30 ibid.

31 ibid., p. 12.

required to pay the acquisition costs when they receive no benefit from the acquisition.[32]

3.2.5 Assessment

In order to increase the capital base to recognise the actual capex GasNet submits to have incurred during the AA2 period, the ACCC is required to undertake an ex-post assessment to determine whether the requirements of s. 8.16 of the code have been satisfied.

The prudent investment test requires the proposed cost for a capex proposal to not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice, and to reflect the lowest sustainable cost of providing services. This assessment requires the ACCC to consider whether:

- the new facility exhibits economies of scale or scope and the increments in which capacity can be added and
- the lowest sustainable cost of delivering services over a reasonable timeframe may require the installation of a new facility with capacity sufficient to meet forecast sales of services over that timeframe.[33]

In practice, this invites consideration of whether:

- the capex is required to meet forecast sales of services
- the capex is the most appropriate option for delivering the additional services required, taking into account the availability of other options, i.e. whether the forecast new facility is prudent and
- the capex exceeds the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering services, i.e. whether the proposed cost of the capex proposal is prudent.[34]

In relation to determining which of the s. 8.16(a)(ii) of the code tests to apply, the ACCC considers it is appropriate to apply the system integrity test, given the maintenance nature of the actual capex incurred (which did not increase or augment the capacity of the PTS).[35]

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32 Energy Users Coalition of Australia, *Submission to the issues paper*, 10 August 2007, p. 9.

33 Code, s. 8.17.

34 The ACCC adopted the same approach in the assessment of the proposed Corio loop: see ACCC, *Final Decision: Corio loop*, op. cit., p. 7.

35 The application of the system integrity test is further considered in section 3.34 of this draft decision.

The ACCC has assessed each actual capex project submitted by GasNet and has been assisted by an independent review prepared by Sleeman Consulting.[36]

3.2.5.1 Assessment of approved capex to be incurred during the AA2 period

(i) *Refurbishment of the Gooding compressor*

The ACCC approved $22.21 m to refurbish the Gooding compressor during AA2. This included:

- the installation of a new fuel gas heater system
- the replacement of the backup electricity generator
- the replacement of other obsolete equipment and
- the partial replacement of the wet-seal C307 compressors with dry-seal C402 compressors.[37]

GasNet submits $16.03 m was incurred during the AA2 period for this refurbishment.[38] The ACCC understands the cost savings were realised by refurbishing instead of replacing the existing gas turbine drivers as originally envisaged. Sleeman Consulting notes this implies the gas turbine drivers will need to be overhauled sooner.[39] However, the refurbishment is considered to be prudent given the estimated overhaul cost of a compressor is $0.5 m, significantly less than the estimated $9.0 m of cost savings from the refurbishment.[40]

Given the information currently available, the ACCC considers the $16.03 m incurred to refurbish the Gooding compressor during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of this refurbishment is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$16.03 m to refurbish the Gooding compressor is to be included in the capital base.

(ii) *Refurbishment of the Lurgi pipeline*

The ACCC approved $5.72 m to refurbish the Lurgi pipeline which was originally constructed in 1956.[41] The refurbishment involved the installation of pig launching and receival facilities and modifications to pipeline valves in order to allow use of intelligent pigging to assess the integrity of the pipeline.

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36 Sleeman Consulting, *GasNet Principal Transmission System: Review of Proposed New Facilities Investment*, 19 September 2007.

37 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 179 and 183.

38 GasNet, *Submission*, op. cit., pp. 24 and 25.

39 Sleeman Consulting, op. cit., p. 8.

40 ibid., p. 9.

41 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 179, 180 and 182.

GasNet submits it identified efficiencies resulting in capital savings of $3 m and only incurred $2.82 m. The refurbishment began in 2003 and was completed in 2006.[42] Sleeman Consulting advises the refurbishment involved:

- the installation of pig launching and receival facilities
- the replacement of six main line valves with full-bore valves and
- the removal of nine line valves.[43]

Sleeman Consulting advises in comparison to a green fields cost estimate (which does not include allowances for the removal of old equipment and live-line work) the $2.82 m incurred is aligned with industry expectations and is prudent.[44]

Given the information currently available, the ACCC considers the $2.82 m incurred to refurbish the Lurgi pipeline during AA2 satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of this refurbishment is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$2.72 m to refurbish the Lurgi pipeline is to be included in the capital base.

(iii) ***City gate upgrades and heaters***

The ACCC approved $9.36 m of upgrades to the Dandenong, Wollert and Morwell city gate stations and the Tyers pressure limiting facility to be undertaken during AA2.[45] The upgrades originally included the replacement of equipment at the end of its working life, improvements in operational flexibility, system reliability and safety, the installation of liquid removal facilities and gas heaters at the Dandenong, Tyers and Wollert regulator stations. GasNet submits it incurred $5.38 m for these upgrades during AA2.[46] This is less than the approved forecast of $9.36 m for AA2 which GasNet submits is due to:

- the installation of a gas heater at Tyers was not required as the customer driving this need did not eventuate
- the size of the gas heater installed at the Morwell backup regulator was to be increased and
- the limited availability of valves which has deferred work at the Dandenong city gate (estimated to be $6.09 m) to 2008.[47]

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42 GasNet, *Submission*, op. cit., p. 25.

43 Sleeman Consulting, op. cit., pp. 8 and 9.

44 ibid.

45 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 179, 180 and 182.

46 GasNet, *Submission*, op. cit., pp. 25 and 26.

47 ibid.

Sleeman Consulting confirms deferral of the Dandenong city gate works is consistent with the limited availability of valves due to high levels of demand internationally.[48] Further, Sleeman Consulting concludes GasNet's costing is comparable in magnitude to indicative industry costs and reflects prevailing market conditions given the equipment was sourced through competitive tendering arrangements.[49]

Given the information currently available, the ACCC considers the incurred $5.38 m of city gate upgrades and heaters during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of these upgrades is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$5.38 m for city gate upgrades and heaters is to be included in the capital base.

(iv) *Wollert compressor station automation*

The ACCC approved $3.32 m to automate the Wollert compressor station during AA2. The automation was necessary given the existing control system had reached the end of its useful life and in accordance with accepted industry best practice this involved the installation of the capability for the station to be remotely operable.[50] GasNet submits it incurred $2.76 m.[51]

Sleeman Consulting advises automation costs depend on a number of factors, and can only really be assessed against the costing of past automations. In this regard Sleeman Consulting refers to the automation costs incurred at the Gooding compressor station ($3.0 m) and at the Brooklyn compressor station ($4.8 m), which is consistent with the proposed $2.76 m.[52]

Given the information currently available, the ACCC considers the $2.76 m incurred to automate the Wollert compressor station during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of this automation is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$2.76 m to automate the Wollert compressor station is to be included in the capital base.

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48 Sleeman Consulting, op. cit., p. 10.

49 ibid., pp. 11 and 12.

50 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 180 and 182.

51 GasNet, *Submission*, op. cit., p. 26.

52 ibid.

(v) *Gas chromatographs*

The ACCC approved $0.92 m to install three gas chromatographs at Alansford, Brooklyn and Corio. This was at the request of VENCorp to allow for the heating value of gas at certain points to be calculated with greater accuracy to ensure gas supplied across the system met the requirements of the MSO rules.[53] GasNet submits it incurred $0.46 m during AA2.[54]

Sleeman Consulting advises the incurred $0.46 m cost implies an average of $0.15 m per installation which compares favourably to indicative industry costs of around $0.25 m per installation.[55] The ACCC understands the cost savings realised are due to the use of internal instead of external contracted labour to install the gas chromatographs.[56]

Given the information currently available, the ACCC considers the $0.46 m installation of the three gas chromatographs during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of this automation is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$0.46 m to install the three gas chromatographs is to be included in the capital base.

(vi) *Other maintenance capex*

The ACCC approved $6.06 m for other maintenance capex, which included upgrades to information technology, cathodic protection upgrades, office buildings, station instruments, electronic systems and heat exchangers and the acquisition of field and workshop equipment.[57] GasNet submits it incurred $4.70 m.[58]

GasNet provided the ACCC with a confidential breakdown of the maintenance capex it incurred. The ACCC has assessed this breakdown and considers the capitalisation of these maintenance activities is appropriate. Assessment undertaken by Sleeman Consulting suggests that the scope of GasNet's maintenance capex is appropriate and the incurred costing is prudent.[59]

Given the information currently available, the ACCC considers the $4.70 m of other maintenance capex incurred during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of this automation is

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53 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 181 and 183.

54 GasNet, *Submission*, op, cit., p. 26.

55 Sleeman Consulting, op. cit., p. 13.

56 ibid.

57 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 183.

58 GasNet, *Submission*, op. cit., p. 27.

59 Sleeman Consulting, op. cit., pp. 13 and 14.

consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$4.70 m for other maintenance capex is to be included in the capital base.

3.2.5.2 Assessment of non-forecast capex incurred during the AA2 period

(i) *Brooklyn compressor redevelopment*

GasNet submits $17.46 m was incurred during AA2 as part of the first stage in the redevelopment of the Brooklyn compressor station, which was first constructed in 1972. Four Saturn compressor units were installed in 1979 and two more units in 1982.[60] GasNet submits the redevelopment was necessary because:

- the existing equipment is due for replacement
- the site is congested with limited opportunities for expansion and
- to install dry-seal compressors to prevent the entry of liquids into the gas transmission and distribution networks in accordance with the directive of Energy Safe Victoria.[61]

Assessment undertaken by Sleeman Consulting identifies:

- although the $3 m replacement of the C307 wet-seal compressor fitted to the Solar Centaur unit 11 with a C337 dry-seal compressor moderately exceeds the estimated uninstalled cost of a refurbished compressor, it is considered to be prudent
- the $17 m installation of a new Solar Centaur T4700-C336 compressor in 2007 is prudent given the estimated installed cost of a Solar Centaur package ranges between three to five times the uninstalled cost of around US$4 m and
- the $0.70 m replacement of the cold vent with a modified surplus vent silencer from another site is prudent.[62]

Given the information currently available, the ACCC considers the $17.46 m incurred to redevelop the Brooklyn compressor station during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of these works is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$17.46 m to redevelop the Brooklyn compressor station is to be included in the capital base.

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60 GasNet, *Submission*, op. cit., p. 27.

61 ibid.

62 Sleeman Consulting, op. cit., pp. 14 and 15.

(ii) *South Melbourne cut in*

GasNet submits $2.98 m was incurred during AA2 to install two pig traps on the pipeline that connects the Dandenong to West Melbourne pipeline with the South Melbourne to Brooklyn pipeline. GasNet further submits this was necessary to allow for intelligent pigging to assess the integrity and quality of the pipeline, which was already scheduled for AA2. However, no allowance for the provision of pig traps had been made.[63]

GasNet submits the high costs associated with this project are due to the densely populated area where the work was required to be undertaken. Sleeman Consulting notes the incurred $2.98 m is consistent with industry indicative benchmark costs given the high costs are satisfactorily explained by the need for GasNet to cut-in to existing operating pipelines and the severe access constraints encountered.[64]

Given the information currently available, the ACCC considers the $2.98 m South Melbourne cut-in during the AA2 period is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of the South Melbourne cut-in is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$2.98 m for the South Melbourne cut-in is to be included in the capital base.

(iii) *Wollert compressor station (miscellaneous)*

GasNet submits $2.15 m of works additional to the automation of the Wollert compressor station was incurred during the AA2 period. This included:

- an engine overhaul in 2004
- the replacement of the unit coolers and water tanks with a fin-fan cooler in 2005 and
- a range of electrical upgrade work.[65]

Sleeman Consulting advises the engine overhaul was prudent given the engine overhaul interval is 30 000 hours, whereas the unit had completed 38 580 hours. The $0.17 m incurred is also considered to be industry competitive, given the overhaul is expected to cost $0.20 m in 2007 dollars.[66]

The ACCC notes the installation of the fin-fan cooler was coupled with a station recycle valve at $0.83 m. Sleeman Consulting notes the installation of a fin-fan cooler, without an allowance for the removal of old facilities, could exceed $0.50 m

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63 GasNet, *Submission*, op. cit., p. 28.

64 Sleeman Consulting, op. cit., pp. 15 and 16.

65 GasNet, *Submission*, op. cit., pp. 28 and 29.

66 Sleeman Consulting, op. cit., pp. 16 and 17.

and the 300 mm recycle valve would cost at least $0.22 m, and accordingly GasNet's actual expenditure is reasonable.[67]

The electrical upgrade work included:

- the replacement of the existing obsolete motor control system
- the installation of a new backup generator
- the replacement of the existing 30 year old lighting and fittings and
- the upgrade of the existing 22 kv power supply.[68]

Assessment undertaken by Sleeman Consulting confirms the cost incurred is reasonable given the scope of the works undertaken by GasNet.[69]

Given the information currently available, the ACCC considers the $2.15 m of miscellaneous works to the Wollert compressor station during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of these works is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$2.15 m for miscellaneous works to the Wollert compressor station is to be included in the capital base.

(iv) *Pig traps*

GasNet submits it expects to incur $0.72 m to install pig traps on the Bunyip to Pakenham line in 2007, necessary to comply with licence requirements and AS 2885.[70]

The ACCC accepts the installation of pig traps is a prudent initiative given it is the only effective way to assess the integrity and quality of a pipeline. Sleeman Consulting advises the cost of a single 750 mm diameter facility is around $0.53 m if installed when a pipeline is initially constructed. GasNet's expected $0.72 m cost for two pig traps is accordingly assessed to be around 30 per cent below industry indicative benchmark costs.[71]

Given the information currently available, the ACCC considers $0.72 m to install pig traps on the Bunyip to Pakenham line during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of these works is consistent with maintaining the service potential of existing facilities

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67 ibid., p. 17.

68 GasNet, *Submission*, op. cit., pp. 28 and 29.

69 Sleeman Consulting, op. cit., p. 17.

70 GasNet, *Submission*, op. cit., p. 29.

71 Sleeman Consulting, op. cit., pp. 17 and 18.

as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$0.72 m to install pig traps on the Bunyip to Pakenham line is to be included in the capital base.

(v) *Safety and security*

GasNet submits $0.48 m was incurred to install remote monitoring infrastructure at the Dandenong and Pakenham sites, identified as an outcome of the annual audit of its risk management plan it is required to undertake pursuant to the *Terrorism (Community Protection) Act 2003* (*Terrorism Act*).[72] Sleeman Consulting advises the proposed installation and the $0.48 m costing was independently formulated by Counterisk Australia Pty Ltd.[73] On this basis the ACCC considers the $0.48 m incurred by GasNet is prudent.

GasNet also submits $0.79 m to develop dossiers was incurred to undertake formal safety assessments to identify electrical equipment within hazardous areas which have the potential to cause a gas incident in accordance with the *Gas Safety (Safety Case) Regulations 1999* (Vic).[74]

Sleeman Consulting advises the development of dossiers is a specialised task independently developed for GasNet at an estimated cost of $0.475 m.[75] The ACCC considers this is prudent.

However, GasNet further submits a provision of $0.315 m to undertake rectification works as identified in the course of developing the dossiers.[76] Whilst the ACCC acknowledges the likelihood the dossiers may identify rectification works to be undertaken, in the absence of specific identification of these works the ACCC is unable to assess this provision against the requirements of the prudent investment test.

Given the information currently available, the ACCC considers $0.955 m incurred to install the remote monitoring infrastructure and to develop dossiers is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. This does not include the proposed $0.315 m for rectification works. However, this exceeds the proposed $0.79 m, which the ACCC considers GasNet may have inadvertently proposed. The ACCC also considers the purpose of these works is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

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72 ibid.

73 Sleeman Consulting, op. cit., p. 18.

74 GasNet, *Submission*, op. cit., pp. 29 and 30.

75 Sleeman Consulting, op. cit., p. 18.

76 The $0.475 m and the $0.315 m total $0.79 m as proposed by GasNet: see GasNet, *Submission*, op. cit., p. 30.

$0.955 m to install the remote monitoring infrastructure and to develop dossiers is to be included in the capital base.

(vi) *Iona cooler upgrade*

GasNet submits $0.70 m is required to install a new compressor station cooler at Iona by winter 2007 to address a potential breach in the minimum system pressure requirements at Portland and Hamilton.[77]

The ACCC understands expanded cooling capacity results in less pressure drops and higher gas pressures in the downstream pipeline. Assessment undertaken by Sleeman Consulting against a number of alternatives, suggests the installation of expanded cooling capacity is the lowest cost solution to address the potential pressure issues at Portland and Hamilton.[78]

However, Sleeman Consulting's assessment indicates the proposed $0.70 m includes an owner's cost and contingency provisions of 15 and 20 per cent respectively. The ACCC does not consider a contingency provision satisfies the requirements of the prudent investment test.[79] Sleeman Consulting advises for a project of this size, an owner's cost provision of 10 per cent and a 10 per cent allowance for unidentified costs is sufficient to provide a cost estimate which is equally likely to be over or under-forecast.[80]

Given the information currently available, the ACCC considers $0.60 m to install a cooler at the Iona compressor station during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of these works is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$0.60 m to install a cooler at the Iona compressor station in 2007 is to be included in the capital base.

(vii) *Regulators*

GasNet submits it is expected to incur $0.42 m to upgrade the backup regulators at the Dandenong terminal station, where the Lurgi pipeline connects to the metropolitan system. The existing backup regulator is submitted to be near the end of its working life.[81]

Sleeman Consulting confirms that certain gas pressure regulators at Dandenong have reached the end of their operating life and require replacement. Further, Sleeman Consulting notes this replacement will also address a potential capacity issue

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77 GasNet, *Submission*, op. cit., p. 29.

78 Sleeman Consulting, op. cit., p. 18.

79 This is further considered in section 3.3.4.1 of this draft decision.

80 ibid., p. 20.

81 GasNet, *Submission*, op. cit., p. 30.

identified by VENCorp with the Morwell backup regulator. Assessment of the proposed $0.42 m compares favourably to Sleeman Consulting's independent cost estimate of $0.415 m.[82]

Given the information currently available, the ACCC considers $0.42 m to upgrade the backup regulators at the Dandenong terminal station during AA2 is prudent and satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of these works is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$0.42 m to upgrade the backup regulators at the Dandenong terminal station is to be included in the capital base.

(viii) *Maximo*

GasNet submits it has incurred $1.55 m to upgrade its Maximo asset management system, of which $1.38 m is to be allocated to the regulated capital base.[83]

The ACCC understands prior to the upgrade GasNet's use of Maximo was limited to record keeping activities, but has now expanded to encompass access to technical specifications, work procedures, facilities management of maintenance and scheduling of work activities. GasNet submits the improved asset management capabilities of Maximo were necessary for ongoing pipeline operations and maintenance activities. Sleeman Consulting confirms the upgrade of Maximo was a necessary and prudent initiative and is consistent with good industry practice.[84]

Given the information currently available, the ACCC considers the $1.38 m upgrade of Maximo during AA2 satisfies the requirements of s. 8.16(a)(i) of the code. The ACCC also considers the purpose of this upgrade is consistent with maintaining the service potential of existing facilities as they age and deteriorate and satisfies the requirements of s. 8.16(a)(ii)(C) of the code.

$1.38 m to upgrade Maximo is to be included in the capital base.

(ix) *Corporate restructuring costs*

GasNet submits it incurred in excess of $10 m in relation to the takeover by the APA Group in 2006 and $8.84 m is to be allocated to the regulated GasNet business.[85] In support of its claim for the inclusion and capitalisation of its acquisition costs GasNet states:

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[82] Sleeman Consulting, op. cit., p. 21.

[83] GasNet, *Submission*, op. cit., p. 29.

[84] Sleeman Consulting, op. cit., p. 22.

[85] GasNet, *Submission*, op. cit., p. 30.

- the policy of the Victorian Government was to privatise the PTS as it believed that the most efficient operation of the PTS would be achieved through privatisation
- a natural consequence of private ownership is subsequent merger and acquisition activity and the costs associated with that activity
- corporate restructuring activity will result in efficiencies through economies of scale and scope and
- these economies will eventually be passed on to users through lower tariffs.[86]

Origin Energy, TRUenergy and the EUCV submit that these costs should not be passed on to gas users.[87]

The ACCC agrees with Origin Energy and the EUCV. The code defines new facilities investment as the capital costs incurred in constructing, developing or acquiring new facilities for the purpose of providing services. While a consequence of private ownership is subsequent merger and acquisition activity, the associated costs are not costs which are associated with the delivery of the reference service. The transaction costs of the buyer and seller would be taken into account by each party in arriving at the price that the parties are prepared to buy and sell the asset. It would be no more appropriate to roll the transaction costs of the acquisition into the capital base as it would be to revalue the assets to reflect the purchase price.

A parallel can be drawn with an issue that arose in relation to the ACCC's assessment of the AA proposed by East Australian Pipeline Ltd (EAPL) for the Moomba to Sydney pipeline (MSP). In that case the ACCC inquired of the Australian Pipeline Trust (APT), the owner of EAPL, whether any of the Initial Public Offer (IPO) costs incurred in formation of APT (APT was formed when AGL floated its gas transmission assets) were included in EAPL's forecast costs. APT replied the IPO costs were included in the accounts as reduction in APT's equity as part of the cost of raising equity in accordance with the relevant accounting standard (Para 6 of Accounting Abstract 23). Consequently the IPO costs were not passed on to users through reference tariffs.[88] The ACCC also notes GasNet has not proposed to depreciate these costs, which is inconsistent with efficiencies of scale and scope resulting in the provision of lower reference tariffs for users.

Accordingly, the ACCC considers it is not appropriate to capitalise corporate restructuring costs.

3.2.6 Conclusion

Table 3.2.3 details the ACCC's assessment of GasNet's AA2 actual capex proposals against s. 8.16 of the code.

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86 ibid., pp. 30 and 31.

87 Origin Energy, op. cit., p. 8; Energy Users Coalition of Victoria, *Submission to the issues paper*, 10 August 2007, p. 9; TRUenergy, op. cit., p. 12.

88 ACCC, *Final Decision: East Australian Pipeline Limited access arrangement for the Moomba to Sydney Pipeline System*, 2 October 2003, pp. 48–50.

Table 3.2.3: Draft decision—approved AA2 actual capex

$2006 Dec m	*Forecast*	*Actual*	*Draft decision*	*Difference*
Forecast				
Gooding compressor refurbishment	22.21	16.03	16.03	0.00
Lurgi pipeline refurbishment	5.67	2.82	2.82	0.00
City gate upgrades and heaters	9.21	5.38	5.38	0.00
Wollert compressor station automation	2.86	2.76	2.76	0.00
Gas chromatographs	0.92	0.46	0.46	0.00
Other maintenance capex	5.97	4.70	4.70	0.00
Total forecast	**46.84**	**32.16**	**32.16**	0.00
Non-forecast				
Brooklyn compressor redevelopment	-	17.46	17.46	0.00
South Melbourne cut in	-	2.98	2.98	0.00
Wollert compressor station (miscellaneous)	-	2.15	2.15	0.00
Pig traps	-	0.72	0.72	0.00
Safety and security	-	0.79	0.96	0.17
Iona cooler upgrade	-	0.70	0.60	–0.10
Regulators work	-	0.42	0.42	0.00
Maximo	-	1.37	1.37	0.00
Corporate restructuring	-	8.84	0.00	–8.84
Total non-forecast		**35.42**	**26.66**	**–8.77**
Total actual capex		**67.58**	**58.82**	**–8.77**

Proposed amendment 02

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 2.1 of the proposed revised access arrangement information to reflect table 3.2.3 of this draft decision for roll-in to the capital base.

3.3 Forecast capital expenditure

3.3.1 Code requirements

Section 8.20 of the code allows for reference tariffs to be determined on the basis of new facilities investment or capital expenditure (capex) approved by the relevant regulator which a service provider forecasts to occur during the AA period and demonstrates that there is a reasonable expectation the requirements in s. 8.16 of the code will be satisfied.

The first limb of s. 8.16 of the code, read in conjunction with s. 8.17, requires the relevant regulator first to be satisfied that the proposed forecast capex is prudent in terms of efficiency, in accordance with accepted good industry practice and is designed to achieve the lowest sustainable cost of delivering services.[89] The second limb requires the relevant regulator to also be satisfied that either:

- the anticipated incremental revenue exceeds the cost of the investment (the economic feasibility test) and/or
- the new facility either has system-wide benefits justifying higher tariffs for all users (the system-wide benefits test) and/or
- the new facility is necessary to maintain the safety, integrity or contracted capacity of services (the system integrity test).[90]

The s. 8.16(a)(ii) tests reflect a cost reflective 'user pays' approach which has implications for the recovery of capex costs from users and tariff structures. Applying the economic feasibility test ensures the capital costs incurred are principally recovered from the incremental users who directly benefit and have in practice provided the necessity for the capex proposal.

In contrast, applying the system integrity test generally results in the recovery of capital costs incurred from users localised to the segment of the network where the system integrity is to be maintained. Similarly, in the context of the system-wide benefits test, capital costs are recovered from users across the entire network. Having regard to these cost recovery implications, it is important a capex proposal is assessed against the correct s. 8.16(a)(ii) test.

Further, the approval of forecast capex under s. 8.20 of the code is on the basis that there is a *reasonable expectation* the requirements of s. 8.16 of the code will be met. This does not necessarily imply, nor does it bind the relevant regulator to find, that the requirements of s. 8.16 of the code are met for inclusion in the capital base at the end of the AA period. The relevant regulator normally carries out an ex-post assessment at the time of the subsequent AA review to determine whether the requirements of s. 8.16 of the code have actually been met. The ACCC has

89 Code, s. 8.16(a)(i).

90 Code, s. 8.16(a)(ii).

undertaken an ex-post assessment of the forecast capex approved for AA2 in section 3.2.4 of this draft decision. However, the relevant regulator may undertake this assessment at any time in accordance with s. 8.21 of the code.

3.3.2 Proposal

GasNet proposes a substantial forecast capex program of $334.08 m for AA3 which is approximately 64 per cent of its proposed 2007 rolled-forward capital base and more than five times the $46.84 m approved by the ACCC for AA2.[91] This comprises $245.91 m of augmentations, principally to address anticipated network constraints, and $88.19 m of refurbishments/upgrades to the PTS. Table 3.3.1 sets out GasNet's capex proposals for the AA3 period.[92]

Table 3.3.1: Proposal—AA3 forecast capex

$2006 Dec m	*2008*	*2009*	*2010*	*2011*	*2012*	*Total*
Augmentations						
Northern zone	-	79.03	-	-	-	79.03
Sunbury loop	-	-	-	-	12.46	12.46
Ballarat loop	-	-	29.03	-	-	29.03
Warragul loop	-	4.84	-	-	-	4.84
Pakenham loop	-	1.22	-	-	-	1.22
Stonehaven compressor	-	-	-	-	26.19	26.19
Carisbrook loop	-	-	24.05	-	-	24.05
Brooklyn Lara (Corio) pipeline	63.71	-	-	-	-	63.71
Brooklyn Wollert easements	-	-	5.37	-	-	5.37
Total augmentations	**63.71**	**85.12**	**58.45**	**0.00**	**38.63**	**245.91**
Refurbishments and upgrades						
Gas heating facilities	7.22	1.99	-	-	-	9.21
City gate works	6.68	-	-	-	-	6.68
Pipeline upgrades	2.45	4.13	0.89	1.29	0.89	9.65
Safety and security systems	3.41	0.84	-	-	-	4.25
Brooklyn compressor station	-	37.76	-	11.81	-	49.57
Wollert compressor station	-	1.58	-	-	-	1.58
Other compressor stations	1.34	-	-	-	1.62	2.96
Other	1.76	0.36	0.43	0.82	0.93	4.3
Total refurbishments and upgrades	**22.87**	**46.65**	**1.32**	**13.92**	**3.43**	**88.19**

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91 GasNet, *Revised Access Arrangement 2003–07*, cl. 3.6; ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 183.

92 GasNet states the annual planning report process undertaken with VENCorp has identified a number of areas where there is increasing load growth and anticipated network capacity constraints from 2007/08 onwards: see GasNet, *Submission*, op. cit., pp. 45 and 46; VENCorp, *2006 Gas Annual Planning Report*, ch. 7.

VENCorp has also prepared network planning and timing reports relating to the proposed Northern zone, Sunbury loop, Ballarat loop, Warragul loop, Pakenham and Stonehaven compressor augmentations. These reports are available on the AER's website at www.aer.gov.au.

Total capital expenditure	**86.57**	**131.77**	**59.76**	**13.92**	**42.06**	**334.08**

Source: GasNet, *Proposed AAI*, cl. 3.6.

GasNet submits each capex proposal is reasonably expected to meet the requirements of s. 8.16 of the code.[93] Specifically:

- each capex proposal is reasonably expected to satisfy the requirements of the prudent investment test
- each augmentation proposal, with the exception of the Stonehaven compressor, is reasonably expected to satisfy the requirements of the system integrity test
- the Stonehaven compressor proposal is reasonably expected to satisfy the requirements of the system-wide benefits test[94] and
- each refurbishment/upgrade proposal is reasonably expected to satisfy the requirements of the system integrity test.

In accordance with cl. 4.4 of the proposed AA, GasNet states undertaking these capex proposals will increase reference tariffs during AA3.[95]

3.3.3 Submissions

AGL raises concerns regarding the size of and GasNet's ability to complete its proposed capex program. In particular AGL comments that in the event GasNet's proposal is approved and GasNet fails to meet its program in full, reference tariffs in AA3 will be higher than otherwise warranted.[96]

TRUenergy comments an independent engineer should be engaged to review GasNet's forecast capex proposals. TRUenergy submits GasNet's capex proposals must be justified and supported by VENCorp, and notes the absence of a VENCorp planning report for the Carisbrook loop proposal.[97]

3.3.4 Assessment

In accordance with s. 8.16 of the code, the ACCC has assessed GasNet's proposal in two stages:

- first, whether the capex proposal and the forecast cost to be incurred is reasonably expected to meet the requirements of the prudent investment test in ss. 8.16(a)(i) and 8.17 of the code and

93 GasNet, *Submission*, op. cit., pp. 46–8.

94 On 21 August 2007, GasNet provided further information relating to the Stonehaven compressor proposal: GasNet, *Email to the AER*, 21 August 2007.

95 GasNet, *Submission*, op. cit., pp. 93 and 94.

96 AGL, *Submission to the issues paper*, 26 June 2007, annexure.

97 TRUenergy, op. cit., pp. 12 and 13.

- second, if the capex proposal is considered to be prudent, whether the capex proposal is reasonably expected to meet the requirements of the s. 8.16(a)(ii) test which the ACCC considers is appropriate to apply.

A capex proposal must pass both stages to be approved as forecast capex in accordance with s. 8.20 of the code. In relation to the second stage, the ACCC does not undertake an assessment against s. 8.16(a)(ii) of the code where a capex proposal does not meet the requirements of the prudent investment test. The following consideration outlines the ACCC's considerations in applying the prudent investment test and determining which of the s. 8.16(a)(ii) tests is most appropriate to apply.

3.3.4.1 Assessment against the prudent investment test

The prudent investment test requires the proposed cost for a capex proposal to not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of providing services. The ACCC's considerations in undertaking this assessment is set out in section 3.2.4 of this draft decision.

The ACCC notes the Iona cooler upgrade, considered in section 3.2.5.2 of this draft decision, submitted as actual non-forecast capex projects incurred during the AA2 period includes a contingency allowance. Similarly, the ACCC has identified that a number of GasNet's forecast capex proposals also include a contingency allowance.

The ACCC considers a contingency allowance, which recognises the actual costs of a proposal may differ from the forecast costs due to general uncertainties in the making of a forecast, does not satisfy the requirements of the prudent investment test.

The ACCC considers the provision of a contingency allowance reduces the incentive for a service provider to mitigate the risks of general cost uncertainty by applying appropriate risk management strategies that would be adopted by a prudent service provider acting efficiently and in accordance with good industry practice.

However, a contingency allowance is to be distinguished from a provision for unidentified costs which the ACCC considers is appropriate to recognise the possibility the cost estimate considered to meet the requirements of the prudent investment test may marginally under estimate the actual cost required to be incurred.

The ACCC has applied these considerations in its assessment of GasNet's forecast capex proposals. This assessment has been assisted by the independent review prepared by Sleeman Consulting and advice from, and the independent planning and timing reports prepared by, VENCorp.

3.3.4.2 Assessment against the system integrity test

GasNet submits a number of its augmentations proposals are necessary to avoid an anticipated breach of the minimum system pressure requirements resulting from an anticipated constraint where pipeline capacity is insufficient to meet anticipated demand. GasNet argues that avoiding an anticipated breach of the minimum system pressure requirements is consistent with maintaining the safety and integrity of services on the PTS and justifies assessment against the system integrity test.[98] In this regard GasNet notes:

> In relation to the PTS, one of the key components in providing the Services to VENCorp is maintaining the minimum system pressures. Without the augmentations, the minimum system pressures would not be maintained resulting in uncontrolled and unpredictable outages near the fringe points of the connected gas distribution networks. These outages could also subsequently impact on the safety of the gas networks. On this basis, the augmentations are required to maintain the integrity of the PTS.[99]

VENCorp notes the consequences of a breach of the minimum system pressure requirements are:

- VENCorp would not meet the obligations set out in the connection deeds;
- Outages may occur near the fringe points (extremities) of the [distribution] system. These outages would be uncontrolled and unpredictable, potentially affecting large numbers of householders and small businesses which may also have safety implications; and
- Outages will affect authorised tariff-V and tariff-D loads in the [distribution] networks.[100]

The ACCC understands the minimum system pressure requirements, as specified in VENCorp's system security guidelines and connection deeds between distribution businesses and VENCorp, are limits based on pressure flow requirements to ensure the supply of gas to all customers connected to the distribution system on a peak day.[101] The ACCC also notes that although GasNet refers to resulting outages 'subsequently impact[ing] on the safety of the gas networks',[102] a case substantiating a credible safety concern has not been made by GasNet. For this reason, the ACCC has considered GasNet's proposals in the context of the *integrity* element and not the safety element of the system integrity test.

In justifying this submission GasNet argues it is necessary to consider the ordinary meaning of the system integrity test and states:

> Integrity is defined as "the state of being whole, entire or undiminished" or of "sound unimpaired condition". Further, safety is referred to as "the quality of insuring against hurt, injury, danger or risk".[103]

The ACCC accepts this interpretation of 'integrity' is reasonable. Further, when read together with the reference to 'maintain' in the system integrity test, the ACCC considers the application of the system integrity test can be interpreted to assess a

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98 GasNet, *Submission*, op. cit., p. 47.

99 ibid.

100 VENCorp, *Letter to the AER*, 6 April 2007, p. 3 (appendix x of this draft decision).

101 VENCorp, *System Security Guidelines Issue 7*, May 2005, pp. 13–20. The connection deeds are confidential agreements between distribution businesses and VENCorp.

102 GasNet, *Submission*, op. cit., p. 47.

103 ibid.; VENCorp, *Letter to the AER*, op. cit., p. 3.

capex proposal which can be characterised as being of the purpose of ‘maintaining the continuity and reliability of services’.

The ACCC acknowledges there is a prima facie case to be argued that avoiding a breach of the minimum system pressure requirements is consistent with maintaining the continuity and reliability of supply. However, in the context of the augmentations GasNet proposes, this approach fails to distinguish between a capex proposal which ‘increases’ services to meet an anticipated increase in demand and a capex proposal which ‘maintains’ services at existing levels of demand. The ACCC notes that in the case of GasNet’s augmentation proposals the underlying driver is not an anticipated breach of the minimum system pressure requirements but rather an anticipated increase in demand, of which a failure to address, causes the anticipated constraint.[104] Accordingly, the ACCC considers these augmentation proposals are principally expansive and better characterised as addressing an anticipated increase in demand, not an anticipated breach of the minimum system pressure requirements. For these reasons, the ACCC does not consider it is appropriate to assess GasNet’s augmentation proposals against the system integrity test.

Accordingly, the ACCC proposes that GasNet demonstrate how the augmentation proposals submitted to be necessary to address an anticipated breach in the minimum system pressure requirements are reasonably expected to satisfy the requirements of the prudent investment test.

Application of the economic feasibility test involves an assessment of a capex proposal in its entirety over its life. This requires a forecast of volumes over the life of the project, sustainable at the prevailing reference tariff, and a forecast of costs. The economic feasibility test is satisfied if the net present value of the incremental revenue (revenue less non-capital costs) exceeds the capital costs.

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104 GasNet also acknowledges the anticipated increase in demand is the principal cause:

> If the augmentations are not undertaken, this anticipated load growth will lead to breaches of the minimum system pressures as prescribed in the VENCorp System Security Guidelines and the connection deeds between VENCorp and the relevant distribution businesses.

GasNet, *Submission*, op. cit., p. 45.

3.3.4.3 Augmentation capex proposals

(i) *Northern zone*

VENCorp has identified there is currently insufficient capacity in the Northern zone to achieve the 17 TJ/day of authorised MDQ for exports through Culcairn on days of high system demand.[105] This is due to an expected average load growth of 2.7 per cent per annum in the Northern zone between 1999 and 2010 and the anticipated increase in exports across the Interconnect to supply a number of users, including the new Uranquinty power station in NSW.[106] GasNet submits this proposal is necessary to:

- restore the capability of the PTS to export 17 TJ/day of authorised MDQ across the Interconnect as allocated to GasNet at market start and
- address an anticipated breach of the minimum system pressure requirements on the Echuca lateral at Shepparton on the assumption that imports on the Interconnect will be below 15 TJ/day in AA3.

To address these concerns GasNet proposes $79.1 m to:

- expand the Wollert Compressor station
- loop the pipeline from Wollert to line valve 3 and
- develop a new compressor station at Euroa.

The ACCC notes assessment of a capex proposal against the prudent investment test not only involves consideration of not only the proposed capital costs but also the ongoing opex costs associated with the capex proposal are prudent. In this regard, the ACCC notes GasNet did not take into account how the ongoing maintenance and fuel compressor operating costs that would be incurred as part of this proposal. This is a relevant consideration given expanding system capacity generally involves increasing compression or the looping of an existing pipeline. Sleeman Consulting advises the ongoing costs associated with developing a new compressor station at Euroa to increase compression will exceed the ongoing costs associated with pipeline looping.[107]

As part of this proposal GasNet proposes $39.56 m to redevelop the Wollert compressor station which involves the replacement of the three existing Solar Saturn wet-seal compressors with two new Solar Centaur dry--seal compressors.[108] Assessment undertaken by Sleeman Consulting supports this redevelopment on the grounds:

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105 VENCorp, *Planning Report (P003)—Northern Zone (Planning)*, April 2007, p. 7.

106 ibid.

107 Sleeman Consulting, op. cit., p. 23.

108 GasNet, *Submission*, op. cit., pp. 58 and 59.

- it ensures the availability of sufficient compressor power to meet anticipated requirements
- it will yield efficiency gains even when full power is not required and reductions in environmental emissions and
- it represents the lowest cost solution.[109]

The unit cost of a Solar Centaur 40 compressor package is estimated to be US$4.0 m (approximately A$5.0 m), and the completed installation cost, depending on difficulty, is estimated to range between three to five times the unit cost. Accordingly, accounting for installation costs, the decommissioning and removal of the existing Solar Saturn compressors and pipe-work, the proposed $39.56 m to install two units is considered to be reasonable, as each unit works out to be roughly four times the unit cost. This is based on the expectation that the completed installation cost of a single Solar Centaur 40 compressor package ranges between three to five times the unit cost depending on the difficulty of installation.

However, in view of the ongoing costs consideration, Sleeman Consulting proposes instead of developing a new compressor station at Euroa, an alternative augmentation to loop the pipeline for 35 km to line valve 5 instead of the 12 km to line valve 3 GasNet proposes.[110] The further looping addresses the anticipated constraint, avoids the need for the Euroa compressor station and reductions in ongoing opex costs. Advice sought from VENCorp confirms Sleeman Consulting's alternative proposal will address an anticipated breach of the minimum system pressure requirements and restore the export capability across the Interconnect. Table 3.3.2 compares GasNet's and Sleeman Consulting's proposals.

Table 3.3.2: Northern zone cost comparison

$ m	*GasNet*	*Sleeman Consulting*
Expansion of Wollert compressor station	39.6	39.6
Pipeline looping	14.6	37.7
Development of Euroa compressor	24.9	-
Total capital costs	**79.1**	**77.3**

Source: Sleeman Consulting, p. 24.

As GasNet's proposal only exceeds Sleeman Consulting's cost estimate by 2 per cent, the ACCC considers the proposed $79.1 m is reasonably expected to satisfy the requirements of the prudent investment test. However, having regard to the greater ongoing opex costs associated with the Euroa compressor, the ACCC considers Sleeman Consulting's proposal to further loop the pipeline to line valve 5 results in the lowest sustainable cost which is considered to be consistent with the requirements of the prudent investment test. GasNet's proposal would otherwise

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109 Sleeman Consulting, op. cit., p. 43. Sleeman Consulting specifically notes a 'Solar Centaur turbine at 50 per cent load is marginally more efficient that [sic] a Solar Saturn turbine at full load': at fn 76.

110 ibid., pp. 23 and 24.

result in increased opex costs, which the ACCC considers is not consistent with the requirements of s. 8.37 of the code.[111]

In assessing this proposal against s. 8.16(a)(ii) of the code, the ACCC considers GasNet has not provided a sufficient case to justify assessing this investment entirely under the system integrity test. In this regard, the ACCC has considered this proposal as addressing first the restoration of the export capability of authorised MDQ and second the anticipated breach of the minimum system pressure requirements. As detailed above, in relation to the anticipated breach of the minimum system pressure requirements, the ACCC considers it is more appropriate to assess this proposal against the economic feasibility test. However, in relation to the restoration of the capability to export 17 TJ/day of authorised MDQ across the Interconnect, for the following reasons the ACCC considers this appears to be necessary to maintain the integrity of services and assessment against the system integrity test for this portion of the Northern zone augmentation is appropriate.

The ACCC notes in the context of the PTS as a market carriage capacity management system, authorised MDQ is not an absolute capacity right and does not confer firm transmission rights on its holders as is the case in a contract carriage system. However, it is an instrument which confers financial benefits upon the holder by providing a curtailment hedge (a user will only be curtailed to their allocated authorised MDQ in the event VENCorp reduces system demand back to system capacity), an uplift hedge and a bid order right in the wholesale market.

The ACCC understands GasNet was allocated the export capability of 17 TJ/day of authorised MDQ across the Interconnect at market start in 1997. GasNet and VENCorp submit this capacity has diminished due to load growth on the PTS as users have exceeded their authorised MDQ allocations and/or authorised loads and this capability is now limited in periods of heavy PTS usage.[112] This has not been a significant issue to date as export demand has been minimal and exports have typically flowed during the summer period when PTS demand is low. This demand would have otherwise provided a need for the availability of this capability to be maintained.

The ACCC notes VENCorp, as the independent system operator of the PTS, is able to maintain system pressures within the required limits by either curtailing users who exceed their authorised loads or where applicable requiring users to reduce demand to their authorised MDQ allocation. This implies VENCorp is theoretically able to maintain the export capability of 17 TJ/day of authorised MDQ through the Interconnect for GasNet to allocate. However, identifying the users who exceed their authorised loads and from whom load is to be reduced may be difficult given the majority of users are diffused residential customers.

Studies, based on planning assumptions, indicate that the full export capability of 17 TJ/day cannot be delivered under 1 in 20 peak day conditions with the existing

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111 GasNet's opex costs are further considered in chapter 5.1 of this draft decision.

112 GasNet, *Submission*, op. cit., p. 48; see generally VENCorp, *Network Planning Report (T003)—Northern Zone (Timing)*, April 2007.

infrastructure. It is worth noting that demand in the Northern zone has increased from 76 TJ/day in 1999 to 93 TJ/day in 2005, absorbing the 17 TJ/day allowance for exports. This is largely outside GasNet's control and has nevertheless led to the prevailing situation where GasNet does not currently have the capability to allocate the 17 TJ/day of authorised MDQ.

The ACCC considers the occurrence of unauthorised loads on the PTS is threatening the continuity and reliability of services, which depends on the export capability of 17 TJ/day of authorised MDQ, which was provided for at market start, being available. Accordingly the ACCC acknowledges there is a reasonable expectation on the part of both GasNet and the Interconnect users intending to respectively provide and obtain an allocation of the 17 TJ/day of authorised MDQ. Further, failure to restore this capability may put at risk GasNet's ability to meet existing contractual obligations which rely on this allocation. This is a relevant consideration as ss. 2.24 and 2.25 of the code requires the ACCC to have regard to preserving existing contractual obligations and not to deprive contractual rights a service provider or a user would otherwise be entitled to. Accordingly, restoring this capability is consistent with maintaining the continuity and reliability of services.

In contrast, if the 17 TJ/day of authorised MDQ was provided for in a contract carriage capacity management system, the pipeline operator would be better able to readily prevent other users from exceeding their authorised MDQ allocations. The reliability of services in the context of the capability of the system to deliver the 17 TJ/day of authorised MDQ for users who have contracted for this amount is undermined by other users exceeding their authorised MDQ allocations.

The ACCC acknowledges that although an augmentation is principally expansive, the benefits which accrue from restoring the 17 TJ/day of authorised MDQ is distinguishable for certain users from the situation of an anticipated breach of the minimum system pressure requirements considered above. In this instance the augmentation merely restores the export capability which the ACCC considers is part of maintaining the reliability of services for users on the Interconnect. On this basis, assessment against the system integrity test for an augmentation which restores this export capability of 17 TJ/day of authorised MDQ is appropriate.

However, the ACCC considers there are concerns yet to be addressed arising from the perpetual nature of this authorised MDQ allocation provided to GasNet. In particular, the ACCC notes this allocation of authorised MDQ does not appear to be defined in the context of, or is limited to, the economic life of the Interconnect.[113] In particular, whilst the assessment of this capex proposal against the system integrity test is considered to be appropriate, similar applications for future proposed augmentations justified on the basis of restoring authorised MDQ will be considered by the ACCC on a case by case basis. In the absence of compelling evidence to suggest otherwise, it is likely that any assessment of augmentation capex would be based on the economic feasibility test.

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[113] Whilst an assessment of the merits of this authorised MDQ allocation falls outside the scope of this draft decision, the ACCC notes this may be an issue for VENCorp in reviewing the relevant sections in the MSO rules.

In summary, in relation to the portion attributable to the restoration of the export capability of authorised MDQ, the ACCC considers this is reasonably expected to satisfy the requirements of the system integrity test.

The costs attributed between the portion of the investment which addresses the anticipated breach of the minimum system pressure requirements and the provision of 17 TJ/day of export capability are to be apportioned on the basis of expected gas flows.[114]

(ii) *Sunbury loop*

VENCorp has identified an anticipated breach of the minimum system pressure requirements in winter 2012 at Sunbury, Sydenham and Diggers Rest due to increasing load growth on the Sunbury lateral.[115] GasNet proposes \$12.46 m to address this anticipated breach through a partial 200 mm pipeline duplication of 14.9 km of the Sunbury lateral.[116]

Modelling undertaken by Sleeman Consulting suggests the Sunbury lateral is capable of supplying market requirements, provided gas at a pressure of 4 000 kPa is available at the inlet to the Sunbury lateral from the Brooklyn-Ballan pipeline.[117] As the rating of the Brooklyn-Ballan pipeline is 7 390 kPa, it follows the anticipated breach of the minimum system pressure requirements on the Sunbury lateral is actually the result of insufficient available compression power at Brooklyn.[118]

The ACCC notes it is necessary to assess this proposed augmentation in the context of the Brooklyn compressor station upgrade which incorporates the development of the additional units 12, 13 and 14 compressors as per GasNet's proposed compressor strategy.[119] However, the modelling undertaken in VENCorp's initial planning report only accounts for the unit 12 compressor at the Brooklyn compressor station despite units 13 and 14 anticipated to be completed in 2010.[120]

Further modelling sought from VENCorp suggests that the minimum system pressure requirements are unlikely to be breached in 2012 under 1 in 20 peak day conditions with the installation of the units 13 and 14 compressors in 2010. Taking into account the APA Group advice on their proposal to complete installation of

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114 A capex proposal may be assessed against more than one of the tests in s. 8.16(a)(ii) of the code. The ACCC previously approved assessment against the economic feasibility test and the system-wide benefits test in the context of approving the Southwest pipeline: see ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 56–9.

115 VENCorp, *Network Planning Report (P001)—Sunbury (Planning)*, March 2007, pp. 5, 7 and 8.

116 GasNet, *Submission*, op. cit., p. 49.

117 Sleeman Consulting, op. cit., p. 28.

118 ibid.

119 GasNet, *Compressor Strategy 2007 to 2017*, March 2007 (GasNet, *Submission*, op. cit., attachment C).

120 VENCorp, *Network Planning Report (P001)—Sunbury (Planning)*, op. cit., p. 7.

Brooklyn compressor units 13 and 14 by 2009, VENCorp also indicates that a pressure constraint is unlikely to occur at Sunbury before 2015.

Given the information currently available, the ACCC considers the proposed $12.46 m to augment the Sunbury lateral is not reasonably expected to satisfy the requirements of the prudent investment test in s. 8.16(a)(i) of the code.

(iii) ***Ballarat (Mt Franklin to Ballan loop)***

VENCorp has identified an anticipated breach of the minimum system pressure requirements at the inlet to the Ballarat city gate during winter 2010 due to increasing load along the Brooklyn-Ballarat pipeline.[121] To address this anticipated breach GasNet proposes $29.03 m to duplicate 40.1 km of the Mt Franklin to Ballan 150 mm pipeline with a 300 mm pipeline.[122]

The initial modelling undertaken by VENCorp which identified the anticipated breach assumed only 1 700 kW of duty compression power was available at the Brooklyn and Wollert compressor stations during AA3.[123] However, this is contrary to GasNet's proposed configurations for the Brooklyn and Wollert compressor stations which suggest 3 500 kW of duty compression power will be available during AA3. Based on advice from Sleeman Consulting, the ACCC requested further modelling from VENCorp to assess the impact of the reconfigured Brooklyn and Wollert compressor stations. The further modelling suggests that minimum system pressure requirements are unlikely to be breached at Ballarat in 2010 under 1 in 20 peak day conditions with the availability of a 3 500 kW compressor. VENCorp also advises taking into account the APA Group advice on their proposal to complete the installation of Brooklyn compressor units #13 and #14 by 2009, indicate that a network constraint is unlikely to occur at Ballarat before 2015.

Given the information currently available, the ACCC considers the proposed $29.03 m to duplicate a portion of the Mt Franklin to Ballan pipeline is not reasonably expected to satisfy the requirements of the prudent investment test in s. 8.16(i)(a) of the code.

(iv) ***Warragul loop***

The Lurgi pipeline services Pakenham South, Cranbourne and Lyndhurst. VENCorp has identified an anticipated breach of the minimum system pressure requirements on the Lurgi pipeline in winter 2009 due to growth in these areas and the proposed expansion of a large commercial customer.[124] To address this anticipated constraint

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121 VENCorp, *Network Planning Report (P002)—Ballarat (Planning)*, March 2007, p. 7; GasNet, *Submission*, op. cit., p. 50.

122 GasNet, *Submission*, op. cit., p. 50.

123 VENCorp, *Network Planning Report (P002)—Ballarat (Planning)*, op. cit., pp. 7 and 8.

124 id., *Network Planning Report (P002)—Warragul (Planning)*, March 2007, p. 9; id., *Network Planning Report (T004)—Warragul (Timing)*, March 2007, pp. 7–11.

GasNet proposes $4.84 m to duplicate 4.8 km of the 100 mm Warragul pipeline with a 150 mm pipeline.[125]

The ACCC considers GasNet's augmentation proposal is appropriate to address the anticipated breach. However, Sleeman Consulting notes the proposed $4.84 m may appear excessive due to a number of factors, such as the route the pipeline is proposed to take.[126] Further, this proposal incorporates a 20 per cent contingency allowance, which the ACCC does not consider satisfies the requirements of the prudent investment test. Table 3.3.3 details Sleeman Consulting's cost estimate.

Table 3.3.3: Warragul loop cost estimate

$ m	*Cost estimate*
Pipeline	0.401
Construction	2.470
Facilities and hot-taps	0.510
Access and approvals	0.125
EPCM and owner's costs	0.526
Provision for unidentified costs	0.403
Total	**4.434**

Source: Sleeman Consulting, p. 29.

The proposed $4.84 m is approximately 9 per cent greater than Sleeman Consulting's cost estimate. The ACCC notes Sleeman Consulting's estimate is conservative as it includes a 10 per cent allowance for unidentified costs. On the basis of the information available, the ACCC considers that $4.43 m is reasonably expected to satisfy the requirements of the prudent investment test in s. 8.16(a)(i) of the code.[127]

However, the approval of this proposal for setting reference tariffs for AA3 is contingent on GasNet demonstrating assessment against the economic feasibility test in s. 8.16(a)(ii)(A) of the code. As detailed above, the ACCC does not consider it is appropriate for a proposal which addresses a breach of the minimum system pressure requirements to be assessed against the system integrity test.

(v) *Pakenham loop*

VENCorp has identified the prospect of excessively high velocities as a consequence of the anticipated constraint identified on the Lurgi pipeline.[128] To address these high

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125 GasNet, *Submission*, op. cit., p. 50.

126 Sleeman Consulting, op. cit., p. 29.

127 The 10 per cent provision for unidentified costs is an allowance for costs incurred by GasNet which Sleeman Consulting has not identified: see Sleeman Consulting, op. cit., pp. 29 and 30. The ACCC considers this is consistent with the requirements of the prudent investment test.

128 VENCorp, *Network Planning Report (T007)—Warragul (Timing and Planning)*, March 2007, pp. 7 and 8.

velocities GasNet proposes $1.22 m to duplicate the remaining 450 m of 80 mm section of the Pakenham South branch with a 150 mm pipeline.[129]

Sleeman Consulting advises the erosional velocity of an 80 mm pipeline operating at a pressure of 2.76 MPa should not exceed roughly 25 m/s.[130] VENCorp notes that flow velocities are anticipated to reach 22 m/s during peak periods in 2009 and the gas pressure on the pipeline is less than 2.76 MPa.[131] Whilst the anticipated velocities do not breach the approximate threshold of 25 m/s, the ACCC considers there is merit in addressing this concern.

As shown in table 3.3.4, Sleeman Consulting's cost estimate is only 3 per cent less than the proposed $1.22 m which suggests GasNet's proposal is reasonable. However, the ACCC notes given only 450 metres of pipeline is required, GasNet is likely to benefit from reduced costs by coordinating material orders for both the Warragul and Pakenham looping projects. The ACCC assumes GasNet will coordinate its material acquisitions where possible to take advantage of any cost economies of scale.

Table 3.3.4: Pakenham loop cost estimate

$ m	*Cost estimate*
Pipeline	0.060
Construction	0.626
Access and approvals	0.030
EPCM and owner's costs	0.357
Provision for unidentified costs	0.107
Total	**1.181**

Source: Sleeman Consulting, p. 30.

Given the information currently available, the ACCC considers $1.22 m is reasonably expected to satisfy the requirements of the prudent investment test in s. 8.16(a)(i) of the code.

In relation to the assessment of this proposal against the system integrity test, GasNet submits velocities above 15 m/s are inconsistent with maintaining the integrity of the pipeline.[132] However, GasNet has not demonstrated how high velocities can impact the safety or integrity of services. In the absence of further justification, the ACCC considers the requirements of the system integrity test are not reasonably expected to be satisfied.

129 GasNet, *Submission*, op. cit., p. 51.

130 Sleeman Consulting, op. cit., p. 30.

131 VENCorp, *Network Planning Report (T007)—Warragul (Timing and Planning)*, op. cit., p. 8.

132 GasNet, *Submission*, op. cit., p. 51; In this regard VENCorp states 'GasNet has advised that velocities above 15 m/s are inconsistent with maintaining the integrity of the pipeline': ibid., p. 8.

(vi) *Stonehaven compressor*

As the next staged development to supplement the construction of the Corio loop, GasNet proposes $26.19 m to install a compressor at Stonehaven to increase the capacity of the PTS by 65 TJ.[133] VENCorp's initial analysis notes the appropriate timing to undertake this proposal is uncertain but on the basis of applying a real discount rate of 7 per cent suggests the highest cost benefit may be achieved if it is completed prior to winter 2013.[134]

The ACCC notes VENCorp's analysis assumes approximately half of the involuntary load curtailment associated with the Major System Augmentation Report (Corio loop report) analysis could be derived from installing a compressor at Stonehaven.[135] The ACCC has reviewed this analysis and observes that the timing of the augmentation is sensitive to this assumption. A 10 per cent reduction in the level of estimated benefits results in a negative market benefit. VENCorp also concludes that the analysis is only indicative and further analysis may produce different results.[136]

In contrast, GasNet submits the appropriate discount rate to apply is its proposed real WACC of 5.74 per cent.[137] GasNet argues a discount rate of 7 per cent is excessive because it incorporates the time value of money which discriminates between capex early and customer benefits later (e.g. avoidance of curtailment, avoidance of use of alternative fuels). GasNet argues that the correct 'community-wide' discount rate to apply, consistent with welfare economics, is the social time preference rate and considers a (real) value between 3 and 5 per cent is reasonable. Further, GasNet argues that the proposed reference tariff will only generate a stream of future cash flows which have the same present value as the proposed upfront capex if discounted at the real WACC of 5.74 per cent. In order to consistently compare customer benefits against annual costs, the appropriate costs to compare are the annual reference tariff payments determined at the real WACC of 5.74 per cent. Applying this discount rate suggests the highest net market benefits are derived if this augmentation is completed prior to winter 2012.[138]

GasNet also submits VENCorp's analysis did not account for the benefits of increased competition, which would increase the benefits of the compressor without increasing costs and would bring forward the optimal timing of this proposal from

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133 GasNet, *Submission*, op. cit., pp. 51 and 52.

134 VENCorp, *Network Planning Report (P007)—Stonehaven (Timing and Planning)*, April 2007, pp. 5, 7 and 8.

135 ibid., p. 8.

136 ibid., p. 9.

137 GasNet, *Submission*, op. cit., p. 52.

138 id., *Email to the AER*, 21 August 2007; The ACCC notes the AER has considered this issue in the context of the regulatory test, which notes the appropriate discount rate to apply is the service provider's real WACC: see Australian Energy Regulator, *Final Decision: Regulatory Test version 3 & Application Guidelines*, November 2007, pp. 29 and 30.

winter 2013 to winter 2012.[139] Finally, GasNet submits VENCorp's analysis assumes the Longford injection pipeline is at full capacity (1032 TJ) and this delays the occurrence of supply shortfalls and moves the costs of not having the Stonehaven compressor further into the future. In particular, GasNet argues gas supplies are forecast to decrease and increase respectively from Longford and Port Campbell during AA3 which implies supplies from Longford will be more expensive than supplies from Port Campbell. GasNet maintains if this is correct, VENCorp's analysis understates the benefits of the Stonehaven compressor because it does not account for the more expensive supply of gas from Longford.[140]

However, notwithstanding what the appropriate discount rate to apply may be, the ACCC considers GasNet has not demonstrated a specific case for the Stonehaven compressor and has failed to consider alternative options. Sleeman Consulting supports this conclusion and notes:

- the precise nature of the concerns which the Stonehaven compressor proposes to address has not been quantified
- there is nothing to suggest increases in system linepack is not able to address concerns regarding the dependence on LNG during 1 in 20 peak day demands in 2012 and
- alternative proposals should be identified to compare the proposed Stonehaven compressor against.[141]

In relation to identifying alternative proposals, Sleeman Consulting suggests there may be scope to optimise the operation of the Southwest pipeline (SWP) through a modest increase in gas pressure at the Iona inlet to the SWP.[142] VENCorp also notes a more detailed assessment of the proposed Stonehaven compressor would consider demand-side options and the possibility of looping the existing Longford or SWP pipelines which have not been considered.[143]

Given the information currently available, the ACCC considers the proposed $26.19 m Stonehaven compressor is not reasonably expected to satisfy the requirements of the prudent investment test in s. 8.16(a)(i) of the code.

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[139] The AER has recently noted there are two acceptable approaches to calculating competition benefits (postulated by Dr Darryl Biggar and Frontier Economics) in the context of the regulatory test: see ibid., pp. 41–43.

[140] ibid.

[141] The ACCC notes the installation of the Stonehaven compressor would lift the operational capacity of the SWP to 372 TJ/day, which exceeds GasNet's forecast peak volumes of 328 TJ/day in 2012 and is 65 TJ/day above the lower operating boundary of 307 TJ/day. VENCorp has also noted that the maximum modelled injection volume at Iona into the SWP is 347 TJ/day, based on the assumption of pressures up to the pipeline's maximum allowable operating pressure of 10 000 kPa: see VENCorp, *2006 Gas Annual Planning Report*, pp. 30 and 31.

[142] Sleeman Consulting, op. cit., p. 32.

[143] VENCorp, *Network Planning Report (P007)—Stonehaven (Timing and Planning)*, op. cit., p. 7.

(vii) *Carisbrook loop*

GasNet has identified an anticipated constraint in winter 2010 due to increased demand on the Guildford to Carisbrook pipeline.[144] To address this anticipated constraint GasNet proposes $24.05 m to duplicate 31.4 km of the 150 mm pipeline from Guildford to Carisbrook with a 300 mm pipeline in winter 2010.[145]

The ACCC notes the supporting planning report for this proposal has been provided by GasNet and not VENCorp.[146] However, quite apart from the lack of support from VENCorp, modelling undertaken by Sleeman Consulting suggests if the proposed Northern zone augmentation is undertaken there does not appear to be a case for a constraint arising at Carisbrook.[147]

Further advice sought from VENCorp confirms Sleeman Consulting's conclusions. In particular, VENCorp advises the gas flow assumptions adopted in GasNet's analysis resulting in an anticipated constraint in winter 2010 are unlikely to occur in the timeframe suggested by GasNet because they are based on gas flows measured at Carisbrook, which are not necessarily representative of actual peak demand gas at locations supplied by the Horsham pipeline.[148]

Given the information currently available, the ACCC considers the proposed $24.05 m Carisbrook loop is not reasonably expected to satisfy the requirements of the prudent investment test in s. 8.16(a)(i) of the code.

(viii) *Brooklyn Lara (Corio) pipeline*

The ACCC approved $63.71 m for the Brooklyn Lara (Corio) pipeline (the Corio loop) in June 2006 under s. 8.21 of the code.[149] As the project commenced in 2006, the ACCC determined the capex incurred during AA2 would be treated as actual capex to be rolled into the capital base, with the remainder to be treated as forecast capex in AA3.[150]

Further information provided by GasNet demonstrates construction of the Corio loop has been undertaken in accordance with the ACCC's approval.[151] However, GasNet now proposes the approved $63.71 m be treated on an as-commissioned basis and

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144 GasNet, *Network Planning Report—Carisbrook (Planning and Timing)*, March 2007, pp. 7–10.

145 ibid., pp. 12 and 13; GasNet, *Submission*, op. cit., pp. 52 and 53.

146 TRUenergy made a similar comment: see TRUenergy, op. cit., p. 13.

147 Sleeman Consulting, op. cit., p. 34.

148 VENCorp advises this is due to a non-return valve at Carisbrook on the inlet to the Horsham pipeline: see Sleeman Consulting, op. cit., p. 33.

149 The ACCC considered the requirements of the prudent investment test and the system-wide benefits test were reasonably expected to be satisfied: ACCC, *Final Decision: Corio loop*, op. cit., p. 47. This is further considered in chapter 3.1 of this draft decision,

150 ibid.

151 GasNet, *Email to the AER*, 21 August 2007.

entirely included as forecast capex during AA3 recognised on completion of the Corio loop.

The ACCC does not consider it is appropriate for capex which commences in a prior AA period and is commissioned in the following AA period to be included entirely as forecast capex in the following AA period. Rather, the ACCC considers consistency with ss. 8.15 and 8.20 of the code requires the roll-in of the best estimate of actual capex incurred into the capital base in AA2 and the remaining capex to be included as forecast capex for AA3. At the time of this draft decision, $18.19 m of capex remains to be incurred during the AA3 period.

Given the information currently available, the ACCC considers the remaining $18.19 m of the approved capex for the Corio loop is reasonably expected to satisfy the requirements of the prudent investment test and the system-wide benefits test.

(ix) *Acquisition of easements for the Brooklyn-Wollert loop*

GasNet submits there will eventually be a need, between 2015 and 2020, for a high pressure east to west gas pipeline link to be built around Melbourne which will be vital to the future operation of the PTS.[152] On this basis GasNet proposes to acquire the necessary easements as soon as possible to address the risk that construction of the pipeline along the preferred route may not be possible given anticipated urban encroachment between now and 2015.[153]

The ACCC considers GasNet has not demonstrated a satisfactory need for the development of this high pressure pipeline link or substantiated the likelihood of urban encroachment. If GasNet is able to demonstrate this high pressure pipeline link is indeed necessary, the ACCC considers there may be scope for this proposal to be included in the speculative investment fund in accordance with cl. 4.5 of the proposed AA. Capital costs which are included in the speculative investment fund may be added to the capital base at a later date when the requirements of s. 8.16 of the code are satisfied.

Given the information currently available, the ACCC considers the proposed $5.37 m to acquire easements is not reasonably expected to satisfy the requirements of the prudent investment test.

3.3.4.4 Refurbishment/upgrade capital expenditure

As detailed above, the ACCC considers it is appropriate for a capex proposal that is of a maintenance nature and principally of the purpose to maintain the service potential of existing facilities as they age and deteriorate as well as the quality of services, to be assessed against the system integrity test. The ACCC accepts refurbishment capex can typically be characterised in this manner, but does not

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152 Specifically GasNet submits this is anticipated to be a connection between the Brooklyn-Wollert loop and the Pakenham to Wollert Outer Ring Main at Wollert to the Brooklyn compressor station and the Corio loop: GasNet, *Submission*, op. cit., p. 53.

153 ibid.

consider it is appropriate to characterise upgrade capex in this manner. The exception to this is where upgrade capex forms part of a refurbishment proposal.

The ACCC considers it is appropriate to assess GasNet's refurbishment/upgrade capex proposals against the system integrity test.

(i) *Gas heating facilities*

GasNet proposes that $9.21 m is necessary to install water bath style gas heaters at seven sites around the PTS during AA3 due to forecast increases in injection volumes from sources such as Yolla and Otways gas.[154] The gas heaters are necessary to provide heating facilities to accommodate higher components in the gas stream, linepack and system pressures. GasNet submits this proposal is designed to comply with the Victorian Gas Safety Regulations which stipulate a minimum temperature standard of 2ºC for gas conveyed in a transmission pipeline.[155] This standard recognises gas temperatures fall when gas pressures are reduced at a regulator station and it is accordingly necessary to pre-heat gas to avoid:

- ice forming on control equipment leading to operational failures
- hydrates forming in the pipeline system and
- gas liquids forming in the gas stream if the gas composition contains higher components (e.g. propane).[156]

The ACCC accepts the installation of gas heaters is prudent and the proposed heater sizes reflect the relative gas throughputs and pressure drops at their respective locations. Sleeman Consulting notes in addition to the installation of the gas heaters, this proposal incorporates:

- coriolis metering skids to measure the quantity of gas used as fuel through the heaters at North Laverton, Clonbinane and Wandong and
- a gas chromatograph at Wandong to provide gas quality information given the variability in composition and sources.[157]

Assessment undertaken by Sleeman Consulting suggests the proposed $9.21 m is slightly higher than indicative industry benchmark costs. The ACCC considers this is due to the inclusion of an owner's costs provision in the order of 15 to 17 per cent and a contingency allowance of 20 per cent. As considered above, the ACCC does not consider a contingency allowance is prudent. In relation to the provision for

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154 The seven sites include the Lara city gate ($0.5 m); the Brooklyn city gate ($2.27 m); the Dandenong city gate ($3.44 m); the Wandong city gate ($1.18 m); the Clonbinane city gate ($0.81 m); the North Laverton city gate ($0.51 m); and the DTS Morwell Back-up regulator ($0.50 m). The ACCC notes GasNet currently maintains small heaters at the Brooklyn and Lara city gates (which require upgrades) and is in the process of installing one at the Dandenong terminal station (feeding the small Lurgi Pipeline): ibid., p. 55.

155 GasNet, *Submission*, op. cit., p. 55.

156 ibid.

157 Sleeman Consulting, op. cit., p. 35.

owner's costs, the ACCC considers a 10 per cent provision is reasonable. This is supported by Sleeman Consulting.[158]

Sleeman Consulting further notes an allowance for a gas chromatograph at Wandong has not been adequately justified on the grounds VENCorp has not yet determined a need for it.[159] Removing this allowance reduces the costs to be incurred at Wandong from $1.18 m to $0.84 m.

In accordance with Sleeman Consulting's inclusion of a 10 per cent allowance for owner's costs and unidentified costs and the removal of the gas chromatograph at Wandong, the ACCC considers $7.25 m to install the proposed gas heating facilities is reasonably expected to satisfy the requirements of the prudent investment test. The ACCC also considers the purpose of this proposal is consistent with maintaining the service potential of existing facilities as they age and deteriorate and is reasonably expected to satisfy the requirements of the system integrity test.

(ii) *City gate works*

GasNet proposes that $6.68 m is necessary to upgrade and replace equipment that has reached the end of its working life at the Brooklyn, Lara and Dandenong city gate sites during 2008.[160] The ACCC understands $2.65 m of the proposal relates to the Dandenong city gate upgrade originally scheduled to be completed in AA2 but was delayed due to equipment unavailability.[161] This proposal incorporates:

- extensions to the Brooklyn instrument air system to operate other site equipment and the development of some storage capability
- upgrades to the fuel gas system to provide fuel for operation of gas fired heaters
- installation of liquids collection facilities
- replacement of obsolete regulators
- upgrades to control systems to allow for reliable and automated control and
- upgrade of the bypass system at Brooklyn.[162]

The ACCC notes this proposal includes a contingency allowance which is not considered to be prudent. Excluding this contingency allowance, Sleeman Consulting advises the remaining $6.18 m is consistent with indicative industry benchmark costs.[163]

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158 ibid., p. 36.

159 ibid.

160 GasNet, *Submission*, op. cit., p. 56.

161 ibid.; Sleeman Consulting, op. cit., p. 37.

162 GasNet, *Submission*, op. cit., p. 56; Sleeman Consulting, op. cit., pp. 37 and 38.

163 Sleeman Consulting, op. cit., p. 38.

Accordingly, the ACCC considers $6.18 m for this proposal is reasonably expected to satisfy the requirements of the prudent investment test. The ACCC also considers the purpose of this proposal is consistent with maintaining the service potential of existing facilities as they age and deteriorate and is reasonably expected to satisfy the requirements of the system integrity test.

(iii) *Pipeline upgrades*

GasNet proposes that $9.65 m is necessary for a number of pipeline upgrade projects during AA3. This incorporates:

- the fitting of a pig trap to the Keon Park to Wollert pipeline ($1.57 m)[164]
- the automation of 15 line valves located along the Dandenong to Brooklyn pipeline to allow for the isolation of gas flows in the event of an emergency ($3.24 m)[165]
- the replacement of emergency vents on the Dandenong to West Melbourne pipeline and the Pakenham to Wollert pipeline ($0.40 m)[166] and
- annual provisions for the replacement of cathodic protection facilities, pipeline risk assessments and pipeline coating repairs ($4.44 m).[167]

In relation to the Keon Park to Wollert pipeline, the ACCC accepts the installation of a pig trap is prudent given the pipeline is now 30 years old. Sleeman Consulting considers the proposed $1.57 m is reasonable having regard to the built up nature of the surrounding area and the need to cut into a live gas pipeline and not disrupt the supply of gas.[168]

The ACCC also considers the automation of the 15 line valves along the Dandenong to Brooklyn pipeline is prudent given the pipeline passes through built up areas where there is limited access. Sleeman Consulting notes on the basis of GasNet's proposed $3.24 m, the cost per line valve is slightly more than 50 per cent of the estimated cost of a main line valve installed on a new build basis in a location without access constraints.[169] Having regard to the likely increased costs resulting from limited access to the pipeline and the assessment by Sleeman Consulting, the ACCC considers GasNet's proposed costing to be reasonable.

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164 GasNet has advised the ACCC the correct cost of the pig trap is $1.57 m not $2.45 m as stated in its AA submission.

165 GasNet has advised the ACCC the correct cost of the automation of 15 line valves is $3.24 m not $4.13 m as stated in its AA submission.

166 GasNet has advised the ACCC the correct cost of the replacement of emergency vents is $0.40 m not $1.29 m as stated in its access arrangement submission.

167 GasNet, *Submission*, op. cit., pp. 56 and 57.

168 As a benchmark it is noted the equivalent installation on a green fields basis is estimated to be $0.45 m per facility and in this context an additional 75 per cent for work on a live gas pipeline in a built up area is considered reasonable. Sleeman Consulting, op. cit., p. 38.

169 ibid., p. 39.

The replacement of the emergency vents on the Dandenong to West Melbourne pipeline is understood as necessary because the 22 existing Unibolt enclosures are no longer serviceable or compliant with modern operating requirements. Sleeman Consulting suggests the proposed $0.40 m, at $18 000 per replacement, is reasonable.[170]

In relation to the proposed $4.44 m of annual provisions, the ACCC considers the replacement of cathodic protection facilities and pipeline coating repairs are prudent and reasonably expected to satisfy the requirements of the prudent investment test. However, $2.0 m of these annual provisions relate to pipeline risk assessments. The ACCC understands this is an allowance for the necessary capital works identified from these risk assessments. As these works have not yet been identified, the ACCC does not consider it is appropriate for this allowance to be included as NFI for the purposes of the code. Accordingly, the ACCC considers the proposed $2.0 m for pipeline risk assessments is not reasonably expected to satisfy the requirements of the prudent investment test.

In accordance with removing the proposed $2.0 m for pipeline risk assessments, the ACCC considers $7.65 m for this proposal is reasonably expected to satisfy the requirements of the prudent investment test. The ACCC also considers the purpose of this proposal is consistent with maintaining the service potential of existing facilities as they age and deteriorate and is reasonably expected to satisfy the requirements of the system integrity test.

(iv) *Safety and security systems*

GasNet proposes that $2.93 m is necessary for security upgrades at the Gooding, Brooklyn, Wollert compressor stations and at the Longford and Lara city gates during AA3. This proposal incorporates alarm systems, security fencing, lighting, close circuit television, related communications requirements and additional stocks of emergency equipment, in accordance with GasNet’s obligations pursuant to the *Terrorism (Community Protection) Act 2003* (Vic).[171]

GasNet also proposes $1.32 m of safety expenditure to continue hazardous area risk assessments and any replacement or upgrade of electrical equipment identified as necessary during AA3.[172]

The ACCC notes the proposed $2.93 m reflects costs independently formulated by a security industry specialist which Sleeman Consulting confirms is reasonable, prudent and consistent with industry best practice.[173]

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170 ibid.

171 GasNet, *Submission*, op. cit., p. 57. In support of its proposal GasNet provided the ACCC with a confidential breakdown of the security related facilities.

172 ibid.

173 Sleeman Consulting, op. cit., p. 40.

However, the ACCC is not satisfied the proposed $1.32 m of safety expenditure meets the requirements of the prudent investment test. The ACCC does not consider an allowance for the replacement or upgrade of unidentified electrical equipment can be appropriately characterised as new facilities investment reasonably expected to satisfy the requirements of the prudent investment test.

Accordingly, the ACCC considers the proposed $2.93 m for security upgrades is reasonably expected to satisfy the requirements of the prudent investment test. The ACCC also considers this purpose of this proposal is consistent with maintaining the service potential of existing facilities as they age and deteriorate and is reasonably expected to satisfy the requirements of the system integrity test.

(v) *Brooklyn compressor station*

GasNet proposes that $49.57 m is necessary to continue the redevelopment of the Brooklyn compressor station that started during AA2.[174] This redevelopment is proposed to address the age and obsolescence of the Brooklyn compressor station and meet the safety requirements adopted by Energy Safe Victoria relating to the prevention of liquids entering into the gas transmission and distribution networks. Table 3.3.5 details a breakdown of GasNet's refurbishment proposal for AA3.

Table 3.3.5: Brooklyn compressor refurbishment proposal

Unit	*Type*	*Description*	*Proposal*
6	Solar Saturn T1202	Installed 1979	Remove
7	Solar Saturn T1300	Installed 1979	Remove
8	Solar Saturn T1200	Installed 1982	Remove
9	Solar Saturn T1300	Installed 1982	Remove
10	Solar Centaur T4000-C306	Integrated skid: cannot be upgraded to dry-seal. Can only pump to Geelong.	Replace with new Solar Centaur dry-seal compressor
11	Solar Centaur T4000-C337	Dry-seal compressor. Can only pump to Geelong.	Relocate
12	Solar Centaur T4000-C336	Dry-seal compressor. Installed 2007.	n/a
13	Solar Centaur	Dry-seal compressor. To be installed.	Install

Source: Sleeman Consulting, p. 42.

The removal of the existing Solar Saturn compressor stations, the replacement of unit 11 and the installation of unit 13 accord with the prevailing directive of Energy Safe Victoria that dry-seal compressors are to be utilised in preference of wet-seal compressors to prevent injections of oil into the pipeline.[175] GasNet submits the relocation of unit 11 is necessary to make way for additional pipeline systems to be completed by 2011 in accordance with VENCorp's Vision 2030 report.[176]

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[174] See chapter 6.3 of this draft decision where GasNet proposes to roll into the capital base that incurred during AA2 for the Brooklyn compressor station.

[175] This is reflected in a letter from Energy Safe Victoria to GasNet which has been provided to the ACCC: Energy Safe Victoria, *Letter to Christine O'Reilly*, 27 March 2006.

[176] GasNet, *Submission*, op. cit., p. 58.

Comparison of GasNet's proposed costs against an independent estimate prepared by Sleeman Consulting suggests it is reasonable, prudent and consistent with good industry practice.[177] Table 3.3.6 details Sleeman Consulting's estimate.

Table 3.3.6: Brooklyn compressor station cost estimate

$ m	*Cost estimate*
2 × Solar Centaur	10.00
Installation costs (mid-range estimate)	30.00
Relocation of compressor #11	7.50
Demolition and removal of redundant plant	2.00
Sleeman Consulting estimate	**49.50**
GasNet proposal	**49.57**

Source: Sleeman Consulting, p. 42.

Accordingly, the ACCC considers the proposed $49.57 m to redevelop the Brooklyn compressor station is reasonably expected to satisfy the requirements of the prudent investment test. The ACCC also considers the purpose of this proposal is consistent with maintaining the service potential of existing facilities as they age and deteriorate as well as maintaining gas quality and is reasonably expected to satisfy the requirements of the system integrity test.

(vi) *Wollert compressor station*

GasNet proposes that $1.58 m for a fuel gas system at the Wollert compressor station is necessary to comply with Solar technical requirements.[178] Further information provided by GasNet reveals $0.05 m of the proposed $1.58 m as being necessary for fencing upgrades, which implies a proposed cost of $1.53 m for the fuel gas system.

The ACCC considers $1.53 m fuel gas system is unnecessary given the cost of a fuel gas skid inclusive of heating is already included in the $39.56 m redevelopment cost. This was subsequently confirmed by GasNet with the ACCC, and is supported by Sleeman Consulting.[179] However, the proposed $0.05 m for fencing upgrades is considered prudent.[180]

Excluding the proposed $1.53 m fuel gas system, the ACCC considers $0.05 m for fencing upgrades additional to the redevelopment of the Wollert compressor station is reasonably expected to meet the requirements of the prudent investment test. For the reasons detailed above, the ACCC considers this proposal is also reasonably expected to meet the requirements of the system integrity test.

177 Sleeman Consulting, op. cit., p. 43.

178 GasNet, *Submission*, op. cit., p. 59.

179 Sleeman Consulting, op. cit., p. 44; GasNet, *Email to the AER*, 11 September 2007.

180 Sleeman Consulting, op. cit., p. 44.

(vii) *Other compressor station upgrades*

GasNet proposes that $2.96 m is necessary for upgrades at the Iona and Gooding compressor stations. This incorporates:

- at Gooding, the overhaul of one of the compressor units and the installation of a fire suppression system ($0.99 m) and
- at Iona, the upgrade of the existing control system ($1.62 m) and the installation of a fire suppression system ($0.30 m).[181]

Assessment undertaken by Sleeman Consulting estimates the cost of overhauling a Solar Centaur compressor station is around $0.50 m after 30 000 hours of operation. Further information provided by GasNet indicates the installation of a fire suppression system at Gooding was $0.54 m. This implies a cost of $0.45 m ($0.99 m less $0.54 m) for the overhaul of the compressor unit at Gooding, which marginally exceeds Sleeman Consulting's estimate.[182]

The proposed installations of a Marioff hi-fog fire suppression system at the Gooding and Iona compressor stations is considered to be a prudent initiative consistent with the continued long-term operation of both compressor stations. Sleeman Consulting confirms the proposed costing of $0.30 m is based on vendor pricing and is accordingly considered to be reasonable, prudent and consistent with good industry practice.[183]

The existing control system at Iona was installed in 2001 and is reasonably expected to be serviceable and reliable until at least 2012. In this regard the ACCC considers the proposed $1.62 m upgrade of the existing control system at Iona during AA3 is not prudent.

Accordingly, the ACCC considers $1.29 m for upgrades at the Iona and Gooding compressor stations is reasonably expected to meet the requirements of the prudent investment test. For the reasons detailed above, the ACCC considers this proposal is also reasonably expected to meet the requirements of the system integrity test.

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181 GasNet, *Submission*, op. cit., pp. 44 and 45. The ACCC notes the total of these upgrades ($0.99 m+$1.62 m+$0.30 m) is $2.91 m, which is marginally less than GasNet's proposal.

182 Sleeman Consulting, op. cit., p. 44.

183 ibid.

(viii) *Other refurbishments and upgrades*

GasNet proposes that $4.30 m is necessary for other refurbishments and upgrades during AA3. GasNet did not detail nor substantiate this proposal. Accordingly, neither the ACCC nor Sleeman Consulting have been unable to assess whether this proposal is reasonably expected to satisfy the requirements of the prudent investment test.[184]

3.3.5 Conclusion

For the purposes of this draft decision, the ACCC considers $18.19 m of the proposed $245.90 m of augmentations and $74.91 m of the proposed $88.20 m of refurbishments/upgrades are reasonably expected to satisfy the requirements of s. 8.16 of the code. Broadly these reductions are principally due to GasNet not having demonstrated a justifiable need for a capex proposal or where a need has been demonstrated, incorrectly justifying the capex proposal against the system integrity test instead of demonstrating assessment against the economic feasibility test.

As detailed above, the ACCC considers the Northern zone, the Warragul loop and the Pakenham loop proposals are reasonably expected to satisfy the requirements of the prudent investment test. In this regard the ACCC encourages GasNet to reconsider these proposals in the context of, and to demonstrate assessment against, the economic feasibility test. Assessment against the economic feasibility test to the satisfaction of the ACCC will ensure these proposals are included as forecast capex for the AA3 period in accordance with s. 8.20 of the code. The ACCC also notes cl. 4.4 of the proposed AA provides GasNet may at any time during the AA3 period submit revisions to increase the capital base to recognise capex which can be demonstrated to satisfy the requirements of s. 8.16 of the code.

Table 3.3.7 details the ACCC’s assessment of GasNet’s capex proposals for the AA3 period against s. 8.16 of the code.

184 ibid., p. 46.

Table 3.3.7: Draft decision—AA3 forecast capex

$2006 Dec m	*Proposal*	*s. 8.16(a) of the code requirements*		*Draft decision*
		s. 8.16(a)(i)	s. 8.16(a)(ii)	
Augmentations				
Northern zone	79.03	79.03	demonstrate against EFT	–79.03
Sunbury loop	12.46	0.00	n/a—does not meet PIT	–12.46
Ballarat loop	29.03	0.00	n/a—does not meet s. 8.16(a)(i)	–29.03
Warragul loop	4.84	4.43	demonstrate against EFT	–4.84
Pakenham loop	1.22	1.22	demonstrate against SIT	–1.22
Stonehaven compressor	26.19	0.00	n/a—does not meet PIT	–26.19
Carisbrook loop	24.05	0.00	n/a—does not meet PIT	–24.05
Brooklyn Lara (Corio) pipeline	63.71	18.19	18.19	–45.52
Brooklyn Wollert easements	5.37	0.00	n/a—does not meet PIT	–5.37
Total augmentations	**245.90**	**102.87**	**18.19**	**–227.70**
Refurbishments/upgrades				
Gas heating facilities	9.21	7.25	approved against SIT	–1.96
City gate works	6.68	6.18	approved against SIT	–0.50
Pipeline upgrades	9.65	7.65	approved against SIT	–2.00
Safety and security systems	4.25	2.93	approved against SIT	–1.32
Brooklyn compressor station	49.57	49.57	approved against SIT	0.00
Wollert compressor station	1.58	0.05	n/a—does not meet PIT	–1.53
Other compressor stations	2.96/2.91	1.29	approved against SIT	–1.62
Other	4.30	0.00	n/a—does not meet PIT	–4.30
Total refurbishments/upgrades	**88.20**	**74.92**	**74.92**	**–13.23**
Total capex	**334.10**	**n/a**	**93.11**	**–241.00**

Notes: PIT—prudent investment test in s. 8.16(a)(i) of the code.
EFT—economic feasibility test in s. 8.16(a)(ii)(A) of the code.
SBT—system integrity test in s. 8.16(a)(ii)(B) of the code.
SIT—system integrity test in s. 8.16(a)(ii)(C) of the code.

Proposed amendment 03

Before the proposed revised access arrangement can be approved, GasNet must:

- amend cl. 3.6 of the proposed revised access arrangement information to reflect table 3.3.7 of this draft decision
- demonstrate how the portion of the Northern zone necessary to address the anticipated breach of the minimum system pressure requirements and the Warragul loop are reasonably expected to satisfy the requirements of the economic feasibility test in s. 8.16(a)(ii)(A) of the code in order to include the amounts the ACCC considers are reasonably expected to satisfy the requirements of the prudent investment test in cl. 3.6 of the proposed revised access arrangement information
- demonstrate how the proposed Pakenham loop is reasonably expected to satisfy the requirements of the system integrity test in s. 8.16(a)(ii)(C) of the code in order to include the amount the ACCC considers is reasonably expected to satisfy the requirements of the prudent investment test in cl. 3.6 of the proposed revised access arrangement information.

3.4 Capital redundancy

3.4.1 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. Such an adjustment occurs at the start of the next AA period to:

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

Before approving a reference tariff which includes such a mechanism, the relevant regulator must take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have on the service provider, users and prospective users. If a reference tariff does include such a mechanism, the determination of the rate of return (under ss. 8.30 and 8.31 of the code) and the economic life of the assets (under s. 8.33 of the code) should take account of the resulting risk (and cost) to the service provider of a fall in the revenue received from sales of services or part of the covered pipeline.

If assets that are the subject of redundant capital subsequently contribute, or make an enhanced contribution, to the delivery of services, the assets may be treated as a new facility having new facilities investment (for the purposes of ss. 8.16(a), 8.17, 8.18 and 8.19 of the code) equal to the redundant capital value increased annually on a compounded basis by the rate of return from the time the redundant capital value was removed from the capital base (s. 8.28 of the code).

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

3.4.2 Current access arrangement provisions

Clause 4.6 of GasNet's second AA allows the regulator to review and, if necessary, adjust the capital base at the beginning of the AA3 period to account for wholly or partially redundant assets, being assets which:

> (a) as a whole no longer contribute to the provision of the Tariffed Transmission Service; or
>
> (b) have a reduced contribution to the provision of the Tariffed Transmission Service due to the partial redundancy of that asset.

3.4.3 Proposal

GasNet states that there are no wholly or partially redundant assets for the AA2 period and it disposed of a small parcel of land valued at $20 000.[185]

GasNet has also amended cl. 4.6 of the proposed AA to identify partially redundant assets as those that 'have a *significantly* reduced contribution to the provision of the Tariffed Transmission Service'.[186] GasNet has not acknowledged or justified this amendment in its submission.

3.4.4 Submissions

No submissions were received on this aspect of the proposed AA.

3.4.5 Assessment

The intent of recognising partially redundant assets is to ensure that GasNet faces appropriate incentives to invest and send corresponding price signals to users.[187] It is also in the interest of users and prospective users that tariffs reflect the cost of providing the service which has been used.[188] Since GasNet is better informed and able to affect investment decisions, and to pass the associated costs onto users, it should face more of the risk associated with assets becoming redundant than that faced by users or prospective users.

The effect of GasNet's proposal would introduce a threshold below which the ACCC would not consider certain assets as being partially redundant. This would have the effect of redistributing the risk of redundancy from GasNet onto users of the PTS and thereby weaken the incentive for GasNet to make appropriate investments. It is not clear that shifting this risk would be appropriate given the intent of the capital redundancy policy. The ambiguity in determining whether an asset's contribution to regulated services had been 'significantly' reduced also weakens the incentives faced by GasNet.

In this context, and in the absence of any justification for GasNet's proposal, the ACCC proposes to not approve the proposed wording of cl. 4.6 and requires GasNet to retain the definition of partially redundant assets that is contained in its second AA.

Proposed amendment 04

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 4.6 of the proposed revised access arrangement and retain the definition of partially redundant assets as it appears in the second access arrangement.

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185 GasNet, *Submission*, op. cit., p. 18.

186 id., *Proposed Access Arrangement*, op. cit., p. 6 (emphasis added).

187 See ss. 8.1(d), 8.1(e) and 8.1(f) of the code.

188 Code, s. 2.24(f).

3.5 Depreciation

3.5.1 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 s. 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.
- 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 s. 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 AA, applied consistently and approved by the relevant regulator.

3.5.2 Current access arrangement provisions

Reference tariffs for the second AA 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.

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 for AA1, the assets had a remaining economic life of 32 and 35 years respectively.

3.5.3 Proposal

For AA3, GasNet proposes the economic lives of the assets in table 3.5.1 be equal to their technical lives, with the exception of pipeline assets.[189]

[189] GasNet, *Submission*, op. cit., p. 61.

Table 3.5.1: Technical life per asset category

Asset category	*AA2*	*AA3*
Compressor stations	30	30
Heaters	20	20
Regulators	30	30
Pipelines	60	60
Telemetry	5	10
Buildings	60	60
Land	n/a	n/a
Office equipment	5	5

Source: GasNet, *Proposed AAI*, p. 6; GasNet, *AAI 2002–07*, p. 6.

GasNet proposes that the economic life of new pipelines be set at 55 years.[190] Table 3.5.2 sets out the different lives per pipeline group used in AA2 and those GasNet proposes for AA3.

Table 3.5.2: Current and proposed economic lives for pipeline groups

Pipeline group	*AA2*	*AA3*
Longford	2023	2023
SWP	2052	2052
Murray Valley	2033	2054
Lurgi	2016	2033
Other existing pipelines	2033	2033
New pipelines	55 years	55 years

Source: GasNet, *Proposed AAI*, p. 6; GasNet, *AAI 2002–07*, p. 7.

GasNet proposes to depreciate the Longford pipeline completely by 2023 as per the economic life approved in AA2.[191] In its 2002 final decision, the ACCC considered analysis by Saturn Resources (engaged by GasNet), which indicated that gas reserves in the Gippsland basin would be depleted by approximately 2023.[192] GasNet believes that there is no new information to suggest any changes to these findings.[193]

Consistent with that approved for AA2, GasNet proposes to depreciate the Southwest pipeline (SWP) over a period of 50 years, with its useful life ending in 2052. In approving the depreciation for the SWP in AA2, the ACCC noted that the use of a longer asset life would result in a lower tariff in the initial years of the pipeline's life and therefore assist the development of its market. The ACCC also noted that it would reassess the life of the SWP in the future as provided for under s. 8.33 of the code.[194]

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[190] ibid.

[191] ibid.

[192] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 187.

[193] GasNet, *Submission*, op. cit., p. 61.

[194] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 191.

GasNet proposes to extend the economic life of the Murray Valley pipeline to 2054, which is its full economic life.[195]

GasNet proposes to extend the economic life of the Lurgi pipeline to 55 years, ending in 2033, as per other existing pipelines.[196]

Table 3.5.3 sets out GasNet's proposed depreciation allowance.

Table 3.5.3: Proposal—depreciation allowance by asset category

2006 Dec $ m	*2008*	*2009*	*2010*	*2011*	*2012*
Pipelines	15.4	16.3	17.1	17.7	17.8
Compressors	4.7	6.6	8.1	8.2	8.9
City gates and field regulators	1.2	1.5	1.5	1.5	1.5
Odourisation	0.0	0.0	0.0	0.0	0.0
Gas quality	0.1	0.1	0.1	0.1	0.2
General land and building	0.8	0.8	0.8	0.5	0.5
Other	0.4	0.5	0.5	0.5	0.5
Total	**22.5**	**25.9**	**28.1**	**28.7**	**29.4**

Source: GasNet, *Proposed AAI*, p. 7 (converted to 2006 Dec $).

3.5.4 Submissions

No submissions were received on this aspect of the proposed AA.

3.5.5 Assessment

3.5.5.1 Longford

As the Longford to Dandenong pipeline was commissioned in 1969, a technical life of 60 years would extend its life to 2029. The pipeline is critical to the supply of gas from reserves in the Gippsland basin to the PTS. The economic life of the pipeline is therefore largely dependent upon continuing production from the Gippsland basin, although is also affected by the supply of gas to users in the Latrobe Valley, including:

- large users such as Australian Paper at Maryvale
- the gas-fired power stations at Jeeralang and Valley Power and
- distribution systems servicing smaller customers in a number of towns.

In its final decision in 2002, the ACCC approved the shortening of the life of the Longford pipeline in the context of GasNet's legitimate business interests in accordance with s. 2.24(a) of the code. It noted that it may reassess this decision in view of future studies relating to reserves in the Gippsland Basin or other factors impacting on the pipeline's useful life.[197]

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195 ibid.

196 As detailed in the RAB model provided by GasNet to the ACCC for assessment.

197 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 190.

There is some information to suggest that production from the Gippsland basin is likely to extend past the forecasts of Saturn Resources and ABARE that formed part of the ACCC's considerations in 2002. Saturn Resources assumed that the Gippsland basin would produce 400 PJ of gas per year from a total 8 000 PJ of recoverable reserves, resulting in depletion of the resource in 20 years (in 2023). While this level of production may be achieved in the future, it is likely to represent the maximum and is much larger than current actual levels of production. For example, production from the basin in 2006 was 232.3 PJ,[198] and is forecast by ABARE to peak at 392 PJ in 2021–22 with production levels of around 250 PJ in 2030.[199] Esso Australia also recently stated that it expects production from the Gippsland basin to continue for approximately another 30 years (i.e. to 2037).[200]

Esso Australia stated that following its most recent gas discovery of 8.5 billions of cubic meters (an increase of approximately 5 per cent on the remaining reserve) it will undertake further comprehensive testing of the basin.[201] Proved and probable reserves of the Gippsland Basin have increased 53.9 per cent since 2005.[202]

Tables 3.5.4 and 3.5.5 indicate that the total production capability of the Gippsland Basin is approximately 9 000 PJ, substantially larger that the 8 000 PJ assumed by Saturn Resources. Table 3.5.4 shows proved and probable gas reserves as at December 2006.

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198 EnergyQuest, *EnergyQuarterly Report*, May 2007, p. 48.

199 Clara Cuevas-Cubria and Damien Riwoe, *Australian Energy: National and State Projections to 2029-30*, ABARE Research Report 06.26, 30 December 2006, pp. 41 and 42.

200 ExxonMobil, *Technology Extends Bass Strait Oil Life*, 30 July 2007, viewed 1 November 2007, <http://www.exxonmobil.com/Australia-English/PA/Newsroom/NewsReleases/AU_NR_MR_2007_Technology_Extends_BassStrait.asp>.

201 id., *Esso Identifies New Gippsland Basin Gas Resource*, 13 August 2007, viewed 1 November 2007, <http://www.exxonmobil.com/Australia-English/PA/Newsroom/NewsReleases/AU_NR_MR_2007_New_Gippsland_Basin_Gas.asp>.

202 EnergyQuest, op. cit., p. 22.

Table 3.5.4: Proved and probable gas reserves for basins supplying Victoria as at 31 December 2006

Basin and Project	*Proved and Probable Reserves (PJ)*
Gippsland	
Gippsland JV	4 025
Kipper	594
Basker/Manta	384
Longtom	350
Patricia Baleen	24
Otway	
Thylacine/Geographe	925
Casino	268
Minerva	247
Henry	128
Bass	
Yolla	315
Total	**7 260**

Source: EnergyQuest, *EnergyQuarterly Report*, May 2007.

Table 3.5.5 lists contingent resources for the Gippsland, Bass and Otway Basins. Contingent resources are those quantities potentially recoverable from known accumulations, but which are not currently considered to be technically mature or commercially viable.

Table 3.5.5: Contingent resources for Victorian gas fields as at 31 December 2006

Project	*Gas reserves (PJ)*
Gippsland JV	3 450
Trefoil	300
Basker/ Manta	155
Halladale/Black Watch	100
Thylacine South	100
Kipper	65
Martha	50
White Ibis	50
Total	**4 270**

Source: EnergyQuest, *EnergyQuarterly Report*, May 2007, p. 29.

In view of the current levels of, and recent increases in, proven and probable gas reserves in the Gippsland Basin, as well as the forecasts of ABARE and Esso, it is reasonable to conclude that the Longford pipeline will be transporting gas from the Gippsland basin beyond 2023. Moreover, the existence of gas distribution networks in numerous towns and a number of large gas users in the Latrobe Valley region indicates that the pipeline will continue to play a role in transporting gas to the region from the Gippsland basin or from interstate.

The ACCC considers that, under s. 8.33(c) of the code, GasNet’s proposed economic life for the Longford pipeline does not reflect changes to the expected economic life of that asset. Based on the information detailed above, the ACCC considers that the economic life should be increased to 60 years (ending in 2029) and the depreciation schedules amended accordingly.

3.5.5.2 Southwest pipeline

In the AA2 revisions, GasNet proposed a remaining economic life of 50 years (ending in 2052). Stakeholders stated that this life may be somewhat long given the uncertainties over gas from the Otway Basin, although it was noted that although further development of the Otway Basin may arise in the future. Furthermore the pipeline was expected to have some use as it was connected to the Underground Storage Facility at Port Campbell and that the longer economic life would reduce tariffs and encourage the usage of the pipeline. In view of s. 2.24(a) of the code, the ACCC considered that development of the market was an appropriate consideration and approved the 50 year life.[203]

The ACCC is not aware of any new developments that would affect the economic life of the Southwest pipeline and maintains the view that a 50 year life is consistent with s. 8.33 of the code.

3.5.5.3 Murray Valley

GasNet has indicated that the depreciation of the Murray Valley pipeline in AA2 was based on an unrealistically short expected life assumed by the pipeline's previous owner, and that its proposal reflects the pipeline's full economic life. The ACCC considers that GasNet's proposal to extend the life of this pipeline to 55 years is consistent with s. 8.33(c) of the code.

3.5.5.4 Lurgi pipeline

GasNet has indicated that its proposal to extend the economic life of the Lurgi pipeline to its full 55 years is based on the pipeline's redevelopment over the AA3 period, and to maintain consistency with the Longford pipeline. In the context of the ACCC considerations on the Longford pipeline, that, in the absence of any reason to the contrary, the assumed economic life of the pipeline should be set at 55 years, and accordingly proposes to accept GasNet's proposal.

3.5.6 Conclusion

As a result of amendments relating to GasNet's proposed capital expenditure, the depreciation schedule now differs from that proposed. An indicative depreciation schedule relevant to this draft decision is set out in table 3.5.6.

[203] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 190.

Table 3.5.6: Draft decision—depreciation allowance by asset category

2006 Dec $ m	*2008*	*2009*	*2010*	*2011*	*2012*
Pipelines	15.83	16.14	16.18	16.20	16.21
Compressors	4.71	5.43	5.73	5.91	6.11
City gates and field regulators	1.13	1.35	1.38	1.37	1.33
Odourisation	0.01	0.01	0.01	0.01	0.01
Gas quality	0.09	0.10	0.09	0.09	0.09
General land and building	0.72	0.72	0.67	0.31	0.23
Other	0.20	0.20	0.20	0.20	0.20
Total	**22.71**	**23.95**	**24.26**	**24.09**	**24.18**

Source: ACCC analysis.

Proposed amendment 05

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.3.3 of the proposed revised access arrangement to reflect table 3.5.6 of this draft decision.

4 Rate of return

4.1.1 Code requirements

Section 8.30 of the code states that the rate of return used in deriving a reference tariff should provide a return 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).

Section 8.31 of the code states the rate of return may be set on the basis of the weighted average return applicable to each source of funds (for example, equity and debt). These returns may be determined using a well-accepted financial model such as the capital asset pricing model (CAPM). 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 if the regulator is satisfied that the objectives set out in s. 8.1 of the code are met.

The accepted approach adopted by the ACCC is to estimate a service provider's required rate of return by calculating the post-tax nominal vanilla weighted average cost of capital (WACC). The WACC is expressed as:

$$WACC = k_e \cdot \frac{E}{V} + k_d \cdot \frac{D}{V}$$

where:

k_e	required rate of return on equity	k_d	required rate of return on debt
$\frac{E}{V}$	market value of equity as a proportion of the market value of equity and debt	$\frac{D}{V}$	market value of debt as a proportion of the market value of equity and debt

Section 8.2(e) of the code states that the relevant regulator must be satisfied that any forecast required represents the best estimates arrived at on a reasonable basis.

4.1.2 Current access arrangement provisions

The ACCC approved a nominal vanilla WACC of 8.93 per cent for AA2. The WACC parameters for AA2 are set out in cl. 3.2 of GasNet's second access arrangement information (AAI) and are reproduced in table 4.1.1.

Table 4.1.1: Approved AA2 WACC parameters

WACC parameter	*Value*
Real risk-free rate	3.33%
Nominal risk-free rate	5.57%
Bond maturity period	10 years
Forecast inflation rate	2.16%
Debt margin	1.71%
Debt raising costs	
Credit rating	
Cost of debt	7.28%
Market risk premium	6.00%
Gearing ratio	60.00%
Value of imputation credits	50.00%
Equity beta	0.973
Return to equity	11.40%
Nominal Vanilla WACC	8.93%
Real Vanilla WACC	6.62%

Source: GasNet, *Proposed AA*, cl. 3.2.

4.1.3 Proposal

GasNet proposes a nominal vanilla WACC of 9.01 per cent for AA3 and submits the WACC parameters are consistent with recent ACCC decisions on AAs for gas transmission pipelines and the AER compendium.[204] Consistent with the application of the post-tax revenue model an allowance for taxation is included in the cash-flows and not the WACC. GasNet's WACC parameters proposals are set out in table 4.1.2.

Table 4.1.2: Proposal—AA3 WACC parameters

WACC parameter	*Proposal*
Real risk-free rate	2.68%*
Nominal risk-free rate	5.85%*
Bond maturity period	10 years
Forecast inflation rate	3.09%
Debt margin	1.14%
Debt raising costs	0.125%
Credit rating	BBB
Cost of debt	7.12%
Market risk premium	6.00%
Gearing ratio	60.00%
Value of imputation credits	50.00%
Equity beta	1.00
Return to equity	11.85%
Nominal Vanilla WACC	9.01%
Real Vanilla WACC	5.74%

Source: GasNet, *Submission 2008–12*, table 6-1.
* to be recalculated at a date closer to the final decision.

GasNet states it is now established that there are a range of outcomes that satisfy the requirements of the code and submits the WACC parameters which are consistent with past ACCC decisions 'are either below, or at the lower end of, the range of

[204] GasNet, *Access Arrangement Submission 2008–12*, 14 May 2007, p. 34.

outcomes that would satisfy the code'.[205] On this basis, and having regard to the changing regulatory framework and the 'desire for policy makers to balance certainty and consistency with the need for flexibility', GasNet submits the ACCC should:

- adopt a cautious approach in moving away from established WACC parameters and
- treat GasNet's proposed WACC parameters as a 'package' and allow GasNet to submit a revised set of WACC parameters in the event the ACCC does not agree to approve any one of GasNet's proposed parameters.[206]

In support of the WACC parameter proposals GasNet submitted a report prepared by Synergies Economic Consulting as part of its AA submission.

Subsequent to its lodgement of revisions, GasNet formally requested the ACCC consider the NERA Economic Consulting (NERA) reports which allege biases in the use of Commonwealth Government securities (CGS) as proxies for the nominal and real risk-free rates as part of the AA review.[207] GasNet did not specify the impact this may have on the proposed WACC.

4.1.4 Submissions

Origin Energy commented on the alleged downwards bias in the nominal and index-linked CGS yields and was of the view that:

> … the [ACCC] should continue with its existing approach which is now well understood by the industry and can be consistently applied across different asset based businesses. The [ACCC] should only vary from this if there are strong and compelling reasons and we do not believe that GasNet has established such a case in this proposal.[208]

AGL and TRUenergy both commented there may be a case to reduce the WACC to reflect the reduction in GasNet's weather related volume risk resulting from its proposed price control formula.[209]

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[205] ibid.

[206] ibid.

[207] GasNet, *Letter to the AER*, 20 June 2007. The Energy Networks Association (ENA) engaged NERA Economic Consulting to assess the suitability of using CGS yields as a proxy for the risk-free rate. See NERA Economic Consulting, *Bias in Indexed CGS Yields as a Proxy for the CAPM Risk Free Rate: A Report for the ENA*, March 2007; and NERA Economic Consulting, *Absolute Bias in (Nominal) Commonwealth Government Securities*, 7 June 2007.

The NERA reports respectively allege an absolute bias in the use of nominal CGS yields to proxy the nominal risk-free rate and a relative bias in the use of indexed CGS yields to estimate the real risk free rate.

[208] Origin Energy, *Submission to the issues paper*, 9 July 2007, p. 8.

[209] AGL, *Submission to the issues paper*, 26 June 2007, annexure; TRUenergy, *Submission to the issues paper*, 27 June 2007, p. 9. GasNet's proposed price control formula is considered in chapter 6.3 of this draft decision.

4.1.5 Assessment

4.1.5.1 Market evidence, certainty and consistency

Section 8.30 of the code requires the regulator to approve a rate of return which is 'commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service'. This in practice necessitates that the relevant regulator review and assess WACC parameters proposals having regard to the prevailing market evidence. WACC parameters cannot be directly observed and must be estimated, which requires the relevant regulator to form a view about the particular parameters that are appropriate.

At the time of this draft decision, the ACCC acknowledges there may be increasing market evidence to suggest the values for certain WACC parameters previously approved by the ACCC may be conservative. However, the ACCC notes departure from these WACC parameters is not appropriate in the absence of compelling and robust market evidence for a change in the relevant parameter. At the time of this draft decision, the ACCC does not consider the market evidence available sufficiently supports a case for departure from the ACCC's accepted approach in estimating WACC parameter values. Further, the ACCC considers given the inter-relationship between WACC parameters, it is important that WACC parameters be subject to a comprehensive review. In this regard the ACCC intends, in conjunction with the AER, to engage with the sector as a whole and undertake a thorough review of all the WACC parameters during 2008.[210]

The ACCC has assessed each of GasNet's proposed WACC parameters consistent with this approach, and where it considers appropriate has provided justifications for revised WACC parameters to be adopted by GasNet. Further, notwithstanding any of the conclusions drawn in this draft decision, the ACCC is entitled to revise its assessment of a service provider's proposed WACC parameters in future decisions, consistent with applicable legislation or regulations and taking into account a settled view on the market data available at that time and having regard to the objective of maintaining certainty and preserving consistency.

4.1.5.2 'Range' approach

GasNet states it is now established there are a range of feasible outcomes that satisfy the requirements of the code and submits the WACC parameters approved by the ACCC 'are either below, or at the lower end of, the range of outcomes that would satisfy the code'.[211]

In assessing a proposed WACC parameter against the requirements of the code, the ACCC considers the proper approach is to compare the service provider's proposal against the ACCC's best estimate of the outcomes that satisfy those requirements. A

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[210] This will coincide with the requirement for the AER to review WACC parameters every five years pursuant to cl. 6A.6.2(f) of the National Electricity Rules (NER) relating to electricity transmission and revised provisions under the new cl. 6 of the NER relating to electricity distribution.

[211] GasNet, *Submission*, op. cit., pp. 33 and 34.

service provider's proposal will not be rejected simply because it does not equate to the ACCC's position. Rather, the ACCC will examine the reasons for the difference between the two positions and only withhold approval if those reasons indicate that the service provider's proposal falls outside the range of outcomes that satisfies the requirements of the code.

This approach recognises in some cases the code may tolerate more than one outcome. For example, applying this approach, the ACCC would accept a service provider's proposal where the differences between the ACCC's best estimate and the service provider's proposal are immaterial or where the arguments in support of the respective outcomes do not clearly favour one over the other.

This provides a practical framework consistent with the observations in *Re Michael; Ex parte Epic Energy*[212] and *Application by GasNet Australia (Operations) Pty Ltd*[213] in the regulatory environment established under the code which:

- avoids debate about whether a figure is the 'correct' outcome or the upper boundary of a 'reasonable range'
- focuses on the reasons for the service provider's proposal and the regulator's response, rather than mechanically comparing a proposed figure with a range of figures and
- enables the relevant regulator to reasonably determine, where necessary, the outcome that best satisfies the requirement of the code in accordance with ss. 8.2(e) and 8.6 of the code.

4.1.5.3 Return on equity

GasNet proposes a nominal required return on equity (k_e) of 11.85 per cent, calculated in accordance with the CAPM. The CAPM is expressed as:

$$k_e = r_f + \beta_e \left(E(r_m) - r_f \right)$$

where:

r_f	nominal risk-free rate	β_e	equity beta
$E(r_m)$	expected return on the market	$E(r_m) - r_f$	market risk premium

The CAPM specifies the return required by equity holders given the opportunity cost of investing in the market (r_f), the market's own volatility (the market risk premium ($E(r_m)$–r_f)) and the relative systematic risk of holding equity in a particular entity (β_e). The ACCC considers the CAPM is appropriate for determining the required k_e and is consistent with the example in s. 8.31 of the code.

212 [2002] WASCA 231.

213 [2003] ACompT 6.

4.1.5.4 Nominal risk-free rate

The nominal risk-free rate (r_f) is the return an investor would expect from an asset with certainty of returns being achieved which cannot be observed directly. The accepted approach of the ACCC is to use the yield on long-term nominal Commonwealth Government securities (CGS) as a proxy for the risk-free rate, as the risk of government default is generally considered to be very low.

GasNet proposes a nominal risk-free rate of 5.85 per cent calculated on the basis of 10 year nominal CGS yields averaged over a 40 day sampling period ending 26 February 2007.[214]

As noted above, GasNet formally requested the ACCC, as part of the AA review, to consider the NERA reports which allege the nominal and indexed CGS yields are biased downwards and no longer appropriate as proxies for the nominal and real risk-free rates. NERA argues special factors have led to the suppression of yields in both nominal and indexed CGS markets, principally attributed to increased institutional demand and reduced supply of nominal and indexed CGS relative to GDP.[215]

In the context of the nominal risk-free rate, NERA alleges there is currently an ‘absolute bias’ in nominal CGS yields and proposes the yields on corporate bonds less matched credit default swap (CDS) rates provide a better proxy for the nominal risk-free rate.[216] NERA approximates the bias as the difference between margins on credit default swap (CDS) markets with the margin between equivalent corporate debt and CGS. NERA suggests an upwards adjustment is necessary where nominal CGS yields are used to proxy the nominal risk-free rate. On 1 March 2007, NERA calculated this adjustment to be 66 bp.[217]

The ACCC is currently reviewing NERA’s work and has received views from the Reserve Bank of Australia, the Australian Treasury and advice from Professor John Handley of The University of Melbourne.[218] Both the RBA and the Treasury do not consider there is an absolute bias in nominal CGS yields.

The Treasury considers the nominal CGS market is a ‘well-functioning’ market and comments an express policy decision was made in 2003 to continue to issue nominal CGS to maintain sufficient liquidity in this market.[219] The Treasury further notes the reduction in nominal CGS is likely to be attributable to increased macroeconomic stability in the economy, (lowering the risk premium associated with holding bonds

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214 GasNet, *Submission*, op. cit., p. 35.

215 NERA Economic Consulting, *Absolute Bias*, op. cit., pp. 3–6.

216 ibid., pp. 8–11.

217 ibid., p. 13: NERA notes this adjustment is to be recalculated accordingly using contemporaneous data.

218 Australian Treasury, *Letter to the ACCC*, 7 August 2007; the Reserve Bank of Australia, *Letter to the ACCC*, 9 August 2007; John Handley, *A Note on the Fisher Equation*, 23 July 2007.

219 Australian Treasury, op. cit., attachment, p. 1.

and the interest rate investors require) and increased demand for long-term bonds from pension funds and Asian central banks, which have led to a structural shift in terms of lowering the financing cost for all entities seeking investment capital.[220]

Further, the methodology employed by NERA to estimate the alleged bias does not acknowledge that CDS contracts reflect the credit and liquidity risk of the banking sector and are therefore not risk-free in the sense contemplated by the CAPM approach. CDS contracts are primarily issued by banks and investment houses which have a higher credit risk than the Australian Government.[221]

In any case where an equity beta of 1.0 is applied, an adjustment to the nominal risk-free rate is inconsequential for the purposes of calculating the WACC.[222] In particular, in relation to the CAPM, an adjustment to the nominal risk-free rate has an equal and offsetting effect in the MRP and would otherwise necessitate a reconsideration of the MRP. Similarly, an adjustment to the nominal risk-free rate also has an equal and offsetting effect in calculating the cost of debt.[223]

On the basis of advice received from the Reserve Bank of Australia (RBA) and the Australian Treasury, the concerns relating to the methodology employed by NERA to estimate the alleged absolute bias and the irrelevance an adjustment to the nominal risk-free rate has for the calculation of the WACC where an equity beta of 1.0 is applied, the ACCC does not consider NERA has to date demonstrated a conclusive case to justify a departure from the accepted approach of using nominal CGS yields to proxy the nominal risk-free rate.

The ACCC considers GasNet's proposal to use 10 year nominal CGS yields averaged over a 40 day sampling period to proxy the risk-free rate satisfies the requirements of ss. 8.30 and 8.2(e) of the code. However, given CGS yields are published daily by the RBA and the CAPM requires the adoption of up to date data, for the purposes of this draft decision, the ACCC has sampled a 40 day moving average of the nominal CGS yields to 27 September 2007. This results in a nominal risk-free rate of 5.95 per cent.

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220 ibid.

221 ibid.

222 The ACCC has approved an equity beta of 1 for the purposes of this draft decision as considered in this chapter.

223 Consider: $k_e = r_f + \beta_e\left(E(r_m) - r_f\right)$ where: $\beta_e = 1$

$$\Rightarrow k_e = r_f + E(r_m) - r_f$$
$$\Rightarrow k_e = E(r_m)$$

In relation to the cost of debt: $k_d = r_f + dm$ where dm = yield on corporate debt – r_f

$\Rightarrow k_d =$ yield on corporate debt

The nominal risk-free rate is to be recalculated over a period agreed upon between the ACCC and GasNet prior to the ACCC's final decision.

4.1.5.5 Forecast inflation rate

The forecast inflation rate is not an explicit parameter to be estimated for the purposes of calculating the WACC. However, it is an input into the PTRM and is used to convert the nominal vanilla WACC into a real vanilla WACC.

The accepted approach adopted by the ACCC in the past has been to estimate the forecast inflation rate as the difference between the yields on 10 year indexed CGS and 10 year nominal CGS applying the Fisher equation as specified:

$$f = \frac{(1 + r_f)}{(1 + r_{rf})} - 1$$

where:

f	forecast inflation rate	r_{rf}	real risk-free rate
r_f	nominal risk-free rate		

Applying this approach, GasNet proposes a forecast inflation rate of 3.09 per cent measured over a 40 day sampling period, to be recalculated over a period ending on a date the ACCC and GasNet agrees to prior to the final decision.[224]

However, GasNet notes there is currently a limited supply of indexed CGS which may lead to a 'one-way bias' if the Fisher equation is applied to estimate the forecast inflation rate. The ACCC notes this proposal raises issues which are somewhat related with those raised in the context of NERA's suggestion that a 'relative bias' exists in indexed CGS yields relative to nominal CGS yields.[225] Both this and GasNet's proposal imply the use of indexed CGS yields to proxy the real risk-free rate as an input into the Fisher equation may result in an overestimate of the forecast inflation rate. In support GasNet refers to the RBA's Statement on Monetary Policy which states:

> The implied medium-term inflation expectations of financial market participants, as measured by the difference between nominal and indexed bond yields were around 3¼ per cent in early November. However, as noted in previous Statements, this measure can be affected by factors unrelated to expectations about inflation, such as changes in institutional demand for indexed securities.[226]

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224 GasNet, *Submission*, op. cit., p. 36; Synergies, op. cit., pp. 54 and 55.

225 See generally NERA Economic Consulting, *Bias in Indexed CGS Yields*, op. cit.

226 GasNet, *Submission*, op. cit., p. 41; Reserve Bank of Australia, *Statement on Monetary Policy*, 13 November 2006, p. 59. The ACCC notes the RBA expressed similar comments in February and May 2007: see Reserve Bank of Australia, *Statement on Monetary Policy*, 12 February 2007, p. 54; and Reserve Bank of Australia, *Statement on Monetary Policy*, 4 May 2007, p. 57.

To address this alleged 'one-way bias' in the event the RBA's observations are correct, GasNet proposes if the Fisher equation yields a result which respectively exceeds the RBA's target band of 2 to 3 per cent or is less than 3 per cent then:

- the forecast inflation rate is to be capped at 3 per cent as this evidences the market is pricing a premium for the risk that the RBA will not be successful in meeting its monetary targets or
- an appropriate adjustment should be made to the risk-free rate as this evidences a possible bias in the nominal and indexed bond rates.[227]

Advice sought from John Handley suggests there may be merit in the NERA arguments in relation to indexed bond yields, in particular in the context of the current demand/supply conditions in the indexed CGS market.[228] This is further supported by the RBA and The Treasury who note the Australian Government has not issued any indexed CGS since February 2003 and there are only three outstanding issues as of August 2007.[229] As a consequence, at this time the ACCC accepts there appears to be some evidence that the yields observed in the indexed CGS market may not provide an appropriate proxy for the real risk-free rate. The corresponding market-implied inflation rate estimated through the Fisher equation is likely to exceed the best estimate of the forecast inflation rate over AA3. On these grounds the ACCC rejects GasNet's proposal that the Fisher equation be used to estimate the forecast inflation rate.

However, the ACCC does not accept NERA's proposed solution to address this concern, by adjusting upwards indexed CGS yields when used as a proxy for the real risk-free rate.[230] In particular, the ACCC has concerns with the methodology employed by NERA to quantify this alleged bias since this is based on the credit spreads of only two corporate entities.[231]

The ACCC notes this issue has been raised before the AER in the context of the 2008 SP AusNet and 2008 ElectraNet electricity transmission determinations. At the time of the AER's draft decision for SP AusNet, the AER rejected the use of the Fisher equation on similar grounds and considered an approach to estimating inflation more directly, having regard to replicable, transparent, objective and widely-available market data was likely to result in the best estimate of the forecast inflation rate.[232]

The ACCC agrees in principle with the approach adopted by the AER but acknowledges there are difficulties in relying upon independent inflation indicators,

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227 GasNet, *Submission*, op. cit., p. 41.

228 John Handley, op. cit., p. 14.

229 The Reserve Bank of Australia, *Letter to the ACCC*, op. cit., p. 3.

230 NERA, *Bias in Indexed CGS Yields as a Proxy for the CAPM Risk Free Rate*, op. cit., p. 21.

231 ibid., pp. 19–21.

232 ACCC, *Draft Decision: SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007, pp. 119–24.

which may adopt differing forecasting methodologies and can provide conflicting estimates. The ACCC also acknowledges there are no other alternative market-based methodologies which exist to objectively estimate the forecast inflation rate. Given these concerns, the ACCC has further refined its approach and considers it is appropriate at this time to be guided by the RBA's assessment of inflationary expectations in adjusting monetary policy. Where the RBA has a bias to tighten monetary policy, it would be reasonable to form the view that inflation will be at the top of the 2 to 3 per cent inflation target range. Where the RBA has a bias to relax monetary policy, inflation expectations will be taken to be at the lower end of the range. Where the RBA has a neutral position, inflation will be taken to be at the mid-point. This approach should provide further certainty to the market in the absence of a well regarded market-based measure.

The ACCC recognises that the current market sentiment is that inflationary pressures in the short to medium term may result in a tendency for the RBA to tighten monetary policy (tightening bias). This is reflected in the RBA's recent *Statement on Monetary Policy* which forecasts the headline and underlying inflation rate for the 4year to June 2008 to be 3 per cent. For the year to June 2009, the RBA has stated:

> … the central forecast is for both underlying and headline inflation to remain near the top of the target range.[233]

Accordingly, the ACCC considers that an inflation forecast of 3 per cent per annum, which is at the upper end of the RBA's target range, provides the best estimate of the forecast inflation rate at this time.[234]

4.1.5.6 Equity beta

The equity beta is a measure of the systematic risk of an individual stock relative to the risk of the market portfolio. Systematic risk is the total risk that cannot be eliminated in a diversified portfolio. Inclusion of other financial or operational risk factors is inconsistent with the underlying principles of the CAPM which assumes investors eliminate non-systematic risk through diversification. An equity beta of 1.0 indicates the risk of a stock is equal to the risk of the market portfolio and an equity beta below or above 1.0 respectively indicates a lower or higher risk relative to the risk of the market portfolio.

GasNet proposes an equity beta of 1.0 consistent with an asset beta of 0.40 and a debt beta of zero. GasNet submits this is consistent with past ACCC gas AA decisions and the AER compendium but is at the lower bound of the range of outcomes permitted under the code.[235] In support GasNet refers to the Synergies report which concludes an equity beta in the range of between 1.0 and 1.2 is

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233 Reserve Bank of Australia, *Statement on Monetary Policy*, 13 August 2007, p. 63.

234 This is consistent with many independent inflation indicators over 2008 to 2009. The ACCC notes most independent inflation indicators beyond 2009 assume a forecast inflation rate of 2.5 per cent, in line with the midpoint of the RBA's target band. This information is currently before the AER and the ACCC in the context of the 2008 SP AusNet transmission determination which is currently under consideration.

235 GasNet, *Submission*, op. cit., p. 40.

appropriate. The ACCC notes in coming to this conclusion Synergies draws on a sample of comparable gas network companies, which includes US gas distribution businesses.

The ACCC has previously noted the complexities of estimating an equity beta for regulated activities, principally because few regulated entities are publicly listed for a sufficient period of time to produce robust data. Further, of the entities listed, most provide services in addition to the regulated service, resulting in the estimated equity beta not accurately reflecting the systematic risk of regulated activities. The accepted approach to address this is to estimate a proxy beta for a group of listed entities which operate in a similar line of business where the systematic risk of the underlying assets is likely to be of a similar magnitude to that of the regulated service provider. In estimating a proxy beta the ACCC has in the past reviewed current beta estimates from the Australian Graduate School of Management (AGSM) for a range of comparable businesses, information from other regulators as well as reliable academic and other studies in the area.

The ACCC has in the past derived re-levered (applying the 60 per cent benchmark gearing ratio) equity betas for five comparable Australian firms.[236] In the 2006 Roma to Brisbane final decision, the proxy group included Australian Pipeline Trust, Envestra, Alinta, Australian Gas Light, GasNet and DUET. The ACCC has since updated this proxy group to reflect the corporate restructuring which has occurred in the Australian energy industry during 2006–07. The updated proxy group removes:

- GasNet (which was acquired by the APA Group in October 2006)
- AGL (which now comprises only generation and retail assets) and
- Alinta Gas (which was acquired by Babcock & Brown/Singapore Power in May 2007).[237]

For calculation purposes, the ACCC took into account raw (unadjusted) beta estimates, set the debt beta to zero and used corresponding gearing levels sourced from Bloomberg. In the Roma to Brisbane final decision, using December 2005 and March 2006 data from the AGSM,[238] the ACCC calculated sample market beta estimates (averaged re-levered betas) of 0.27 and 0.23 respectively. In the context of the updated proxy group and based on June 2007 AGSM data, the ACCC has recalculated a sample market beta estimate of 0.15.[239]

The ACCC notes this reflects the latest change in the constituency of the proxy group. Until 2002, the proxy group included AGL, Envestra and United Energy and

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236 The ACCC notes some of the companies which constitute the proxy group include other non-regulated businesses which are likely to overstate its systematic risk, implying a higher equity beta, and resulting in a more conservative average.

237 ACCC, *Final Decision: Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline*, 20 December 2006, pp. 101 and 102.

238 AGSM uses monthly observations over 48 months of the firm’s trading history (with a minimum of 20 observations).

239 This is the most recent quarter for which AGSM data was available.

in September 2003 GasNet was included and United Energy was removed. Notwithstanding these changes to the proxy group, the ACCC maintains these results are useful in that they suggest an equity beta of 1.0 is or remains conservative.

The ACCC is also aware of the Longeran Edwards valuation report for GasNet in July 2006 which estimated an equity beta range for GasNet between 0.75 and 0.80 on the assumption of a 65 per cent gearing ratio.[240] The re-levered results at the benchmark gearing ratio of 60 per cent results in an equity beta range of 0.66 to 0.70.

As noted above, the ACCC has also had regard to the latest empirical evidence in assessing the proposed equity beta. In 2002 the ACCC engaged ACG to estimate proxy beta values.[241] This report suggested an equity beta for Australian gas transmission companies of just below 0.70 based exclusively on market evidence.[242] ACG also considered data for comparable businesses in the USA, Canada and the UK which resulted in lower beta estimates, supporting the view that Australian estimates are not understated. However, ACG recognised the need for a conservative approach that does not move too far from previous regulatory decisions and recommended a proxy equity beta of 1.0.[243] Similarly, having regard to the desirability of maintaining consistency in regulatory decisions over time, in a report to the Queensland Competition Authority (QCA) in 2004, ACG applied various methods to remove the distorting effects from the dot-com bubble in order to arrive at a forward looking beta estimate concluding that:

> … empirical evidence, together with the desirability of maintaining stability in regulatory decisions over time and consistency in regulatory decisions across companies justifies the use of an equity beta of 1.0 (for a gearing level of 60%) for the Queensland gas distribution. [244]

The ACCC further notes that in 2007, the ESC engaged ACG in the context of the 2007 Victorian gas distribution AA review to provide an assessment of estimating betas exclusively on market evidence.[245] Applying a number of methodologies to eliminate outliers ACG concluded:

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240 GasNet, *Reject the Offer*, 9 August 2006, Annexure. Longeran Edwards prepared an independent valuation report for GasNet in the context of the proposed takeover offer by Babcock and Brown in 2006.

241 The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC*, July 2002.

242 ibid., p. 46.

243 ibid., p. 43.

244 The Allen Consulting Group, Cost of capital for Queensland gas distribution: Report for the QCA, December 2005, p. 58.

245 The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas distribution activities*, June 2007. The scope of the ESC's engagement of ACG was limited to the consideration of reviewing and assessing beta estimation methodologies and empirical evidence, as distinct from what may be the most appropriate equity beta for a regulated gas distributor having regard to matters like the promotion of stability, predictability and consistency: see p. 6.

- using monthly data for the period 1991–98 and 2002–07 the portfolio beta estimates are in the range 0.59 to 0.71 and with upper 95 per cent confidence intervals of 0.83 to 1.17
- using monthly data for the most recent 5 year period the portfolio beta estimates are in the range 0.19 to 0.36 and with upper 95 per cent confidence intervals of 0.44 to 0.75
- applying the Gray and Officer outlier elimination methodology the portfolio beta estimates are in the range 0.53 to 0.64 and with upper 95 per cent confidence intervals of 0.44 to 0.75.

This formed the basis for the ESC's gas distribution draft decision that it may be appropriate to adopt an equity beta value of less than one and that an equity beta of 0.70 was supported by the empirical work undertaken by ACG.[246]

Although ACG in 2002 cautioned against relying exclusively on empirical beta estimates, it noted that there are sound arguments for relying upon the latest market evidence when deriving a proxy equity beta for regulated gas transmission entities. It further noted:

> Moreover, reliance upon the most recent market evidence—particularly where betas are drawn from a credible independent beta estimation service—is also a rule that can be replicated across price reviews and industries, and thus go some way towards reducing the uncertainty associated with the regulatory process.[247]

The ACCC does not accept GasNet's submission that an equity beta of 1.0 is at the lower end of outcomes permitted under the code. GasNet did not provide any relevant information to support a view that the PTS faces increased systematic risks relative to the market portfolio that justify an equity beta above 1.0. Further, the ACCC considers a degree of caution must be exercised in interpreting results which rely on international evidence and accordingly does not consider the results prepared by Synergies are the most appropriate in this regard.[248]

TRUenergy and AGL have commented there may be a case to reduce the WACC in view of GasNet's proposed amendments to its price control formula will reduce weather related volume risk. As considered in chapter 6.3 of this draft decision, the ACCC proposes an amendment to incorporate a +/–5.5 per cent bound on deviations in weather adjusted actual volumes (WAAV). The symmetry of this proposal is such that any prospective risk reduction in terms of reduced losses is equally offset by reduced gains. On this basis the ACCC does not consider this proposal will affect GasNet's non-systematic risk. Further, a case has not been demonstrated to

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246 Essential Services Commission, *Gas Access Arrangement Review 2008–2012: Draft Decision*, 28 August 2007, pp. 383–97.

247 The Allen Consulting Group, Empirical evidence on proxy beta values for regulated gas transmission activities: Final report for the ACCC, op. cit., p. 41.

248 Consistent with these remarks, Synergies states: 'caution needs to be exercised when referencing firms from other jurisdictions, given the potential differences in industry structure and regulation': Synergies Economic Consulting, *Weighted Average Cost of Capital Review for GasNet Australia*, April 2007, p. 42 (GasNet, *Submission*, op. cit., attachment F).

conclusively suggest that GasNet's proposed price control formula which mitigates volume risk will necessarily affect systematic risk to justify and adjustment to the equity beta or the WACC more generally.

Notwithstanding the difficulties in estimating an appropriate equity beta for GasNet, the ACCC acknowledges there is mounting evidence to suggest an equity beta of 1.0 is conservative. This observation, to some extent, is supported in the recent ESC draft decision for the Victorian gas distribution networks, which proposes an equity beta of 0.70 and ESCOSA's final decision (as upheld by the appeals division of the District Court of South Australia), which determined an equity beta of 0.90.[249] However, at this point in time, and in the context of establishing the national regulatory framework for electricity and gas transmission and distribution networks, including the establishment of the AER as the national regulator, the ACCC considers it is important to have due regard to consistency and continuity in regulatory decisions, unless a compelling case can otherwise be demonstrated. In this regard, the AER will be undertaking a comprehensive review of all WACC parameters beginning in 2008 as part of its electricity regulatory responsibilities. This exercise will also inform its views on gas transmission and distribution as it considers these matters in forthcoming gas revenue reviews over this period.

Further, the ACCC notes it may place greater weight on contemporary market evidence in deriving a best estimate of the equity beta in accordance with s. 8.2(e) of the code, noting this may lead to an equity beta of less than 1.0.

4.1.5.7 Market risk premium

GasNet proposes a market risk premium (MRP) of 6 per cent which it submits is consistent with recent regulatory decisions and the AER compendium.[250] GasNet states this proposal is at the lower bound of the range of permitted outcomes under the code.[251] In support, the Synergies report concludes a range of MRP estimates which satisfy the requirements of the code are between 6 and 7 per cent and states:

- there is considerable uncertainty surrounding the estimation of the MRP which can be particularly volatile in the short term
- studies over a longer period (at least 40 years) are required before any conclusion that the MRP has fallen can be reached and
- there is no evidence to suggest the MRP has fallen.

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249 Essential Services Commission, *Gas AA Review 2008–2012: Draft Decision*, op. cit., pp. 396 and 397; Essential Services Commission of South Australia, *Proposed revisions to the access arrangement for the South Australian gas distribution system: Final decision*, June 2006, pp. 68–71; *Envestra v Essential Services Commission of South Australia (No. 2)* [2007] SADC 90 (27 August 2007).

250 GasNet, *Submission*, op. cit., p. 38.

251 The ACCC notes GasNet states '[c]onsistent with its Second Access Arrangement submissions, GasNet considers that the market risk premium has fallen' which is at odds with its general submission. GasNet may have inadvertently made a mistake: ibid.

The ACCC considers the value of the MRP, based on a traditional long term view using historic measures (ex-post measure), remains around 6 per cent.[252] The rationale for using historical data as a measure of the expected MRP is that investors' expectations will be framed on the basis of the market's past performance. The ACCC has previously noted recent analysis indicates that the MRP has fallen to around 3–4 per cent over recent years but notes this may reflect short term market trends and that statistical estimates over shorter periods tend to have higher standard errors suggesting that caution must accompany the interpretation of these results.

A study undertaken by Associate Professor Martin Lally for the ACCC assessed various approaches and estimates of the MRP. Briefly, Lally determined that across four different approaches, the average estimate for the MRP in Australia was 6.1 per cent and concluded:

> … the range of methodologies examined give rise to a wide range of possible estimates for the market risk premium and these estimates embrace the current value of 6 per cent. Accordingly the continued use of the 6 per cent estimate is recommended.[253]

In 2004 ACG reviewed the empirical evidence on the Australian MRP. Based on the evidence presented which includes an analysis of international trends in MRP, ACG concluded that:

> … there is no justification for applying an MRP different from 6%, as is the practice of Australian regulators.[254]

ACG noted that while the point estimate of the MRP provided by historical evidence suggests a higher figure, the qualitative and empirical evidence from ex-ante models provided persuasive evidence that 6 per cent overstates the expected MRP. More recently, ACG having considered historical estimates, forward looking analysis, surveys of market practitioners and previous regulatory decisions recommended a MRP of 6 per cent as the 'best' estimate for regulatory purposes.[255]

Whilst the ACCC is aware historical premiums typically suggest a higher MRP than 6 per cent and forward looking estimates typically suggest a lower MRP than 6 per cent, on the information currently before it, the ACCC currently considers a MRP of 6 per cent is consistent with s. 8.2(e) of the code and in turn will provide for a rate of return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service.[256]

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[252] There appears to be consensus that the MRP cannot be easily predicted over shorter periods and is likely to have poor statistical properties.

[253] Martin Lally, The cost of capital under dividend imputation, June 2002, p. 43.

[254] The Allen Consulting Group, Review of studies comparing international regulatory determinations, March 2004, p. 113.

[255] The Allen Consulting Group, *Cost of capital for Queensland gas distribution*, op. cit., p. 67.

[256] Code, s. 8.30.

4.1.5.8 Cost of debt

Consistent with s. 8.31 of the code, the ACCC considers a benchmarking approach to estimating the cost of debt facing a service provider is preferable to estimating the service provider's actual cost of debt which may not reflect efficient financing sources.

GasNet proposes a cost of debt (k_d) of 7.12 per cent, calculated as:

$$k_d = r_f + dm$$

where:

r_f	the nominal risk-free rate	dm	the debt margin

This approach requires determining the benchmark credit rating of GasNet and the corresponding market observed debt margin (above the risk-free rate). This approach has been applied by the ACCC in past gas transmission regulatory decisions.[257]

4.1.5.9 Benchmark credit rating

GasNet proposes the use of a BBB benchmark credit rating.[258]

In determining the benchmark credit rating of the service provider, ss. 8.30 and 8.2(e) of the code are best met by reference to Australian gas transmission and distribution companies. It is important for consistency with other parameter assumptions that these companies are stand-alone privately owned entities.

Table 4.1.4 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 by Standard & Poor's.[259]

In previous gas transmission determinations, the ACCC sampled AGL, Alinta, Envestra and GasNet.[260] However, it was appropriate to change the sample for this draft decision to reflect a more representative benchmark, as in table 4.1.4. The ACCC has removed GasNet from the sample because of its acquisition by the APA Group in October 2006 and the Diversified Utility and Energy Trust (DUET) was

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257 ACCC, Final Decision: East Australian Pipeline Limited Access arrangement for the Moomba to Sydney Pipeline, 2 October 2003, pp. 116–18; ACCC, Final Decision: GasNet Australia 2002–07, op. cit., pp. 92 and 93.

258 GasNet, *Submission*, op. cit., p. 36.

259 A stand-alone entity is defined as an entity that does not have a parent company (a company that holds the majority of voting stock).

260 ACCC, Final Decision: MSP, op. cit., p. 121; ACCC, Final Decision: GasNet Australia 2002–07, op. cit., p. 90.

included in the sample given that a substantial portion of its asset and energy mix consists of gas transmission and distribution assets.[261]

Table 4.1.3: Credit rating associated with stand-alone gas companies

Company	*Long term credit rating*
Alinta	BBB
Envestra	BBB–
Diversified Utility and Energy Trust	BBB–
APA Group	n/a

Source: Standard & Poor's sourced from Bloomberg

Based on the data in table 4.1.3, the credit rating of all of the companies is either BBB or BBB–. Although averaging the results may suggest a credit rating marginally below BBB is appropriate, the ACCC considers in general table 4.1.4 supports a credit rating associated with a stand-alone gas company of BBB. Accordingly, the ACCC considers the BBB credit rating GasNet proposes is appropriate and complies with the code. The BBB credit rating is supported with reference to the Tribunal decision in the *MSP* matter.[262]

4.1.5.10 Debt margin

GasNet proposes a BBB benchmark credit rating and a corresponding debt margin of 114 bp, calculated as the difference between 10 year CGS yields and the cost of 10 year BBB credit rated corporate debt (data sourced from Bloomberg averaged over a period 40 days ending 26 February 2007.[263] The 10 year term is consistent with the term of the risk-free rate.

Few bonds are issued with a maturity of 10 years in the Australian market. The ACCC's analysis indicates there are no BBB-rated bonds with a 10-year maturity currently available in the market. Accordingly the ACCC is unable to compare the consistency of the yields on BBB-rated bonds provided by Bloomberg against actual yields for the bonds being benchmarked (BBB 10 year bond), as suggested by ACG.[264] The ACCC considers it reasonable to accept the GasNet proposal to determine the benchmark debt margin using Bloomberg data.

The ACCC considers it appropriate to measure the Bloomberg data by taking an average of the spread over the same period (40 working days) used to determine the risk-free rate. This reduces any potential distortions and results in a best estimate arrived at on a reasonable basis which is transparent and consistent with the determination of the other WACC parameters and satisfies the requirements of

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261 DUET has a 62.1 per cent economic interest in the Dampier Bunbury Pipeline (DBP); a 79.9 per cent interest in Multinet in Victoria; and a 25.9 per cent interest in AlintaGas Networks in Western Australia: see <www.duet.net.au> viewed 1 November 2007.

262 Application by East Australian Pipeline Limited [2004] ACompT 8.

263 GasNet, *Submission*, op. cit., pp. 37 and 38.

264 The Allen Consulting Group, 'A' rating debt margin differential between Bloomberg and CBASpectrum—Memorandum, February 2006.

ss. 8.30 and 8.2(e) of the code. Consistent with the calculation of the nominal risk-free rate, the ACCC has recalculated the debt margin for a BBB-rated bond based on Bloomberg data over a 40 day period ending 27 September 2007 for the purposes of this draft decision.

This results in a debt margin of 162 basis points which is to be re-calculated with current data at a date closer to the final decision.

4.1.5.11 Debt raising costs

GasNet proposes debt raising costs of 12.5 bppa to be added to the debt margin and submits this is at the lower end of outcomes permitted by the code. In support of GasNet refers to the 25 bppa approved by the Australian Competition Tribunal for AA2.[265] The ACCC considers GasNet should be provided a benchmark allowance for debt-raising costs and that the best estimate of these forecast costs is one that is based on current costs.

In 2004, the ACCC commissioned ACG to analyse the necessity of benchmarking debt raising costs within the CPI–X incentive regulation framework and to develop a recommended benchmark for debt raising costs based on current market data gathered from publicly available sources as well as interviews with market participants.[266] GasNet submits the ACG report was biased towards bond financing by regulated companies with stable cash flows over time and paid less attention to bank debt, timing issues and the debt raising requirements for large capex plans.[267] However the ACCC does not consider this to be a reasonable criticism of the ACG report on the following grounds:

- The elements of the debt raising costs benchmark is independent of the stability or variability in a regulated entity's cash flows and in any case the ACCC considers the application of the GasNet's proposed price control formula will provide GasNet with relatively stable cash flows.[268]
- ACG notes it was unable to find a robust source for up to date information to benchmark financing costs for bank debt which is required to be consistent with s. 8.30 of the code.[269] This is consistent with use of bond yields to determine the debt margin, as bonds are traded and up to date information is available, consistent with s. 8.30 of the code.
- The debt raising requirements for large capex programs have been considered given the benchmark incorporates multiple bond issue sizes.

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265 GasNet, *Submission*, op. cit., p. 37.

266 Allen Consulting Group, *Debt and equity raising costs*, December 2004.

267 GasNet, *Submission*, op. cit., p. 37.

268 GasNet's proposed price control formula is considered in chapter 6.3 of this draft decision.

269 Unlike corporate bonds which are traded frequently to allow for the availability of up to date information on current yields: see the Allen Consulting Group, *Debt and equity raising costs*, op. cit., p. xiv.

The ACCC considers ACG's benchmarking approach to estimating debt-raising costs is transparent and consistent with the determination of other WACC parameters. In developing the benchmark, ACG calculated a gross underwriting fee benchmark of 5.5 bppa based on a five-year term. To this it added allowances for legal and road show expenses, credit rating fees for the firm and for each issue of bonds and registry and paying charges. The median bond issue size was determined to be $175 m. Through reference to current market evidence, this approach provides the service provider an opportunity to earn a stream of revenue that recovers the efficient costs of delivering the service in accordance with s. 8.1 (a) of the code.

The ACCC has updated ACG's work on the gross underwriting fee and issue size benchmarks by incorporating publicly available current data. The gross underwriting fee has increased from 5.5 bppa in December 2004 to 6.0 bppa in September 2007 and the median bond issue size increased from $175 m to $200 m.[270] Table 4.1.4 shows the updated benchmark debt-raising costs and the total benchmark for different numbers of bond issues based on the ACG's recommended methodology.

Table 4.1.4: Benchmark debt-raising costs for bond issues

Fee	*Explanation/source*	*1 issue*	*2 issues*	*3 issues*	*6 issues*	*7 issues*
Amount raised	Multiples of median bond issue size	$200 m	$400 m	$600 m	$1 200 m	$1 400 m
		bp	bp	bp	bp	bp
Gross underwriting fee	Bloomberg for Australian internal issues, term adjusted	6.0	6.0	6.0	6.0	6.0
Legal and roadshow	$75k–$100k (industry sources)	1.0	1.0	1.0	1.0	1.0
Company credit rating	$30K–$50K: S&P ratings	2.5	1.3	0.8	0.4	0.4
Issue credit rating	3.5 (2–5)bps up-front: S&P ratings	0.7	0.7	0.7	0.7	0.7
Registry fees	$3K per issue: Osborne Associates	0.2	0.2	0.2	0.2	0.2
Paying fees	$1/$1m quarterly: Osborne Associates	0.0	0.0	0.0	0.0	0.0
Total	**Basis points per annum**	**10.4**	**9.1**	**8.7**	**8.3**	**8.3**

Source: ACG, *Debt and equity raising costs*, December 2004, updated by the ACCC.

Based on the notional debt component of GasNet's opening capital base of $339 m ($565 m × 60%) and closing capital base of $381 m ($635 m × 60%), in accordance with the updated benchmark methodology in table 4.1.5, the overall debt size of this amount requires one issue with a corresponding transaction cost of 10.4 bppa.[271]

While GasNet's proposal of 12.5 bppa may be consistent with past decisions, it is not based on current costs. Accordingly, an allowance of 10.4 bppa for debt-raising costs is considered the best estimate arrived at on a reasonable basis as required by

270 The underwriting fee increase is in line with trends reported on Bloomberg.

271 In relation to GasNet's opening and closing capital base, see chapter 3.1 of this draft decision.

s. 8.2(e) of the code. Debt-raising costs could be recovered either through an addition to the WACC or as a direct allowance to operating expenses. ACG recommended either approach. The ACCC considered it appropriate that debt-raising costs be added to the debt margin as proposed by GasNet.

4.1.5.12 Imputation credits

GasNet proposes a value of gamma of 0.50 consistent with previous regulatory decisions which it submits is at the lower end of the range of outcomes permitted under the code. This reflects the view that many owners of pipeline operations in Australia are not Australian taxpayers who do not fully benefit from the Australian taxation imputation system.

GasNet further notes empirical studies based on share movements when shares go ex-dividend are consistent with a value of gamma closer to 0.50 than 1.0, and any adjustment should have a corresponding effect on the market risk premium and be in the direction of zero rather than one.[272]

Consistent with the ACCC's post-tax approach, the value for imputation credits is accounted for in the cash flows.

The assumed value of imputation (or franking) credits is expressed as a proportion of their face value denoted by gamma (γ). 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.

In support the Synergies report argues the value of gamma is now likely to be zero on the basis that the marginal investor is better considered to be a foreign investor, and the introduction of the 45 day rule has effectively precluded foreign investors from deriving any benefit from franking credits.[273]

However, the ACCC does not consider it is appropriate to consider the marginal investor as a foreign investor. To date the ACCC has assumed that the relevant benchmark for regulatory purposes is to assume the average equity investor is

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272 GasNet, *Submission*, op. cit., p. 39.

273 The 45 day rule requires an investor to hold shares for a period of 45 days during a qualification period around the dividend event in order to be eligible to rebate franking credits against their taxation liabilities.

Synergies argues the schemes established by investment banks to allow foreign investors to extract value from franking credits, which relied on foreign investors selling their shares to domestic investors in the period leading up to the payment of the dividend is no longer worthwhile given the extra price risk borne between foreign and domestic investors: Synergies Economic Consulting, op. cit., p. 83.

domiciled in Australia and is entitled to the full benefit of imputation credits.[274] This assumption ensures consistency in applying the CAPM in the context of the Australian market.[275] 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.

The observation that a significant portion of the shareholder base is not subject to Australian taxation is essentially irrelevant to the regulatory framework which consistently assumes the equity investor is domiciled in Australia. In order to adopt a different value of gamma to reflect this observation would require the whole CAPM framework 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 individual CAPM parameters. The ACCC's assumption on the segregation of the Australian market has also been advocated by Associate Professor Martin Lally.[276] In relation to the relevance of foreign investors, Lally concludes:

> … continued use of a version of the Capital Asset Pricing Model that assumes that national equity markets are segmented rather than integrated (such as the Officer model) is recommended. It follows that foreign investors must be completely disregarded. Consistent with the disregarding of foreign investors, most investors recognised by the model would then be able to fully utilise imputation credits.[277]

Notwithstanding the evidence for a gamma value of 1.0 the ACCC has decided to retain an assumed value of gamma equal to 0.5 for the purpose of this draft decision. This is consistent with what was approved in AA2 and other recent regulatory decisions.[278] This maintains a sense of regulatory consistency and reflects one of the concessions aimed at ensuring that the rate of return remains appropriate for the ongoing operation of the business. The ACCC does not agree that a value of 0.5 for gamma is at the lower end of the range of outcomes which would satisfy the code. However, in future decisions, the ACCC retains the option of revising the gamma parameter value taking account of the most recent market evidence.

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274 Resident individual investors receive the full benefit regardless of their tax position, as franking credits are now treated as a refundable rebate rather than as a tax deduction. Complying superannuation funds are preferentially taxed, which in the past, may have resulted in imputation credits being eroded. Under the new tax system, franking credits are paid to the fund as a rebate from the Australian Taxation Office.

275 If this assumption were to change then modifications would have to be made to a number of other parameters including the market risk premium and the equity beta.

276 Martin Lally, The cost of capital under dividend imputation, June 2002.

277 ibid., p. 43.

278 This is consistent with the ESC's draft gas distribution decision which concluded it would be inappropriate to depart from a gamma of 0.5 based on the grounds the empirical evidence it was presented with was not persuasive enough to justify a downwards revision. Similarly, the ESC considered it is inappropriate to raise the gamma value from 0.5 given the range of assumptions relied upon in deriving empirical estimates: see Essential Services Commission, *Gas AA review: Draft Decision*, op. cit., p. 433.

4.1.5.13 Capital structure

To determine the appropriate weighted average cost of debt and equity in the WACC framework, the value of debt and equity as a proportion of an organisation's total value is required. The ACCC applies a benchmark gearing ratio in determining the WACC, rather than the service provider's actual gearing ratio consistent with s. 8.31 of the code.[279]

GasNet proposes a 60:40 debt to equity ratio and submits this is consistent with recent regulatory decisions.[280] In addition, GasNet submits there is no justification to adopt a higher gearing ratio.

Although this proposal is consistent with previous ACCC gas and electricity regulatory decisions and related decisions of other regulators, the actual gearing levels of a sample of comparative gas network companies as detailed in table 4.1.5 suggests a higher benchmark gearing ratio may be more appropriate.

Table 4.1.5: Actual gearing levels for comparable gas network companies

Company	*Actual gearing (debt as a percentage of total capital)*
Envestra	90.29
DUET	75.25
APA	69.12
Average	**74.25**

Source: Bloomberg.

The Synergies report reviews both domestic and foreign gas distribution companies over the last five years and submits the average actual gearing level is 36 per cent.[281] This analysis, however, does not substantiate the inclusion of foreign companies which the ACCC considers may skew the results. Having regard to both the available market data and the desire to preserve consistency as considered above, the ACCC considers at this time there is currently insufficient evidence to substantiate a departure from the status quo of a 60:40 debt to equity ratio.

4.1.6 Conclusion

GasNet proposes a nominal vanilla WACC of 9.01 per cent and a corresponding real vanilla WACC of 5.74 per cent.

The ACCC's assessment of GasNet's proposed WACC parameters for the purposes of this draft decision is set out in table 4.1.7. With the exception of the proposed

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[279] This is consistent with the ACCC's *Statement of principles for the regulation of electricity transmission revenues*—December 2004 (SRP). In the SRP the ACCC stated it would not use actual gearing of the regulated entity, but an appropriate benchmark instead. The ACCC in its MSP final decision noted that a 60:40 debt equity ratio reflects a standard industry structure as evidenced by market data at that time: see ACCC, *Final Decision: MSP*, op. cit., p. 115.

[280] GasNet, *Submission*, op. cit., p. 38.

[281] Synergies Economic Consulting, op. cit., p. 26.

forecast inflation rate and debt raising costs, the ACCC has accepted all of GasNet's proposals. This results in a nominal vanilla WACC of 9.38 per cent and a corresponding real vanilla WACC of 6.19 per cent.

Table 4.1.6 provides a comparison of the draft decision with historical regulatory decisions

Table 4.1.6: Comparison of gas rate of returns

Decision	*Date*	*Nominal return on equity (%)*	*Nominal vanilla WACC (%)*
ACCC final decision for MAPS	Sep 2001	12.6	9.1
ACCC final decision for GasNet (AA2)	Nov 2002	11.2	6.3[(a)]
ACCC final decision for ABDP	Dec 2002	11.7	8.9
ACCC final decision for MSP	Sep 2003	11.3	8.2
ACCC final decision for RBP	Aug 2006	11.70	8.84
ACCC final decision for DVP	Aug 2007	11.97	9.08
ACCC draft decision for GasNet (AA3)	**Oct 2007**	**11.95**	**9.38**
ESC final decision for gas distribution	Oct 2002	11.8	6.8[(a)]
ESC draft decision for gas distribution	Aug 2007	n/a	5.6(a)
ICRC final decision	Nov 2004	10.8–12.0	n/a
ERA final decision GGT	May 2005	9.5–13.4	n/a
ERA final decision Alinta gas networks	July 2005	9.2–11.2	n/a
ERA final decision DBNGP	Nov 2005	9.5–12.7	n/a
QCA final decision for gas distribution	May 2006	11.9	n/a

Source: ACCC various decisions: ESC, *Final decision: gas access arrangements*, October 2002; ICRC, *Final decision: review of access arrangement for ActewAGL natural gas system in ACT*, *Queanbeyan and Yarralumla*, October 2004; ERA, final decisions: *Goldfields Gas pipeline access arrangement*, May 2005; *review of the access arrangement for the Mid-West and South-West gas distribution system*, July 2005; *review of the access arrangement for the Dampier to Bunbury Natural Gas Pipeline*, November 2005. QCA, *final decision: revised access arrangements for gas distribution networks*, May 2006 (Allgas and Envestra decisions).

(a) Real vanilla WACC, others are nominal.

Table 4.1.7: Draft decision—AA3 WACC parameters

WACC parameter	*Proposal*	*Draft Decision*
Real risk-free rate*	2.68%	2.95%
Nominal risk-free rate*	5.85%	5.95%
Bond maturity period	10 years	10 years
Forecast inflation rate	3.09%	3.00%
Debt margin*	1.14%	1.62%
Debt raising costs	0.125%	0.104%
Credit rating	BBB	BBB
Cost of debt	7.12%	7.67%
Market risk premium	6.00%	6.00%
Gearing ratio	60:40	60:40
Value of imputation credits	0.50	0.50
Equity beta	1.00	1.00
Return on equity	11.85%	11.95%
Nominal Vanilla WACC	9.01%	9.38%
Real Vanilla WACC	5.74%	6.19%

* to be recalculated at a date closer to the final decision.

The difference between GasNet's proposal and the ACCC's estimate is primarily due to the increase in the yields of 10 year CGS and 10 year BBB corporate bonds as of 27 September 2007 compared to 26 February 2007 in calculating the nominal risk free rate and the debt margin. These parameters will be recalculated based on a sample ending at a date closer to the final decision.

Proposed amendment 06

Before the proposed revised access arrangement can be approved, GasNet must amend the rate of return in cl. 3.2 of the proposed access arrangement information to reflect the ACCC's estimates set out in table 4.1.7 of this draft decision.

5 Forecast revenue and revenue elements

5.1 Non-capital costs

5.1.1 Code requirements

Sections 8.36 and 8.37 of the code allow 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.

The relevant regulator must also be satisfied that any forecasts in setting a reference tariff represent the best estimates arrived at on a reasonable basis[282] and that the non-capital costs comply with the objectives in s. 8.1 of the code.

Attachment A to the code requires the disclosure in the access arrangement information (AAI) of costs (including wages and salaries, rental equipment, gas used in operations, materials and supply, corporate overheads and marketing) with some disaggregation by zones, services or categories of assets, unless it would be unduly harmful to the legitimate business interests of the service provider, user or prospective user.[283]

5.1.2 Current access arrangements provisions

The non-capital costs forecast for the AA2 period are specified in cl. 3.5 of GasNet's second AAI.[284]

Operating and maintenance costs (including fuel gas) comprise the bulk of GasNet's non-capital costs. In addition allowances were made for a return on inventories and linepack, K-factor carryover, asymmetric risk (self insurance), capital raising costs and regulatory review costs.

5.1.2.1 Operating and maintenance costs

A comparison of GasNet's actual operating and maintenance costs incurred during the AA2 period against that forecast for the AA3 period are set out in figure 5.1.1.

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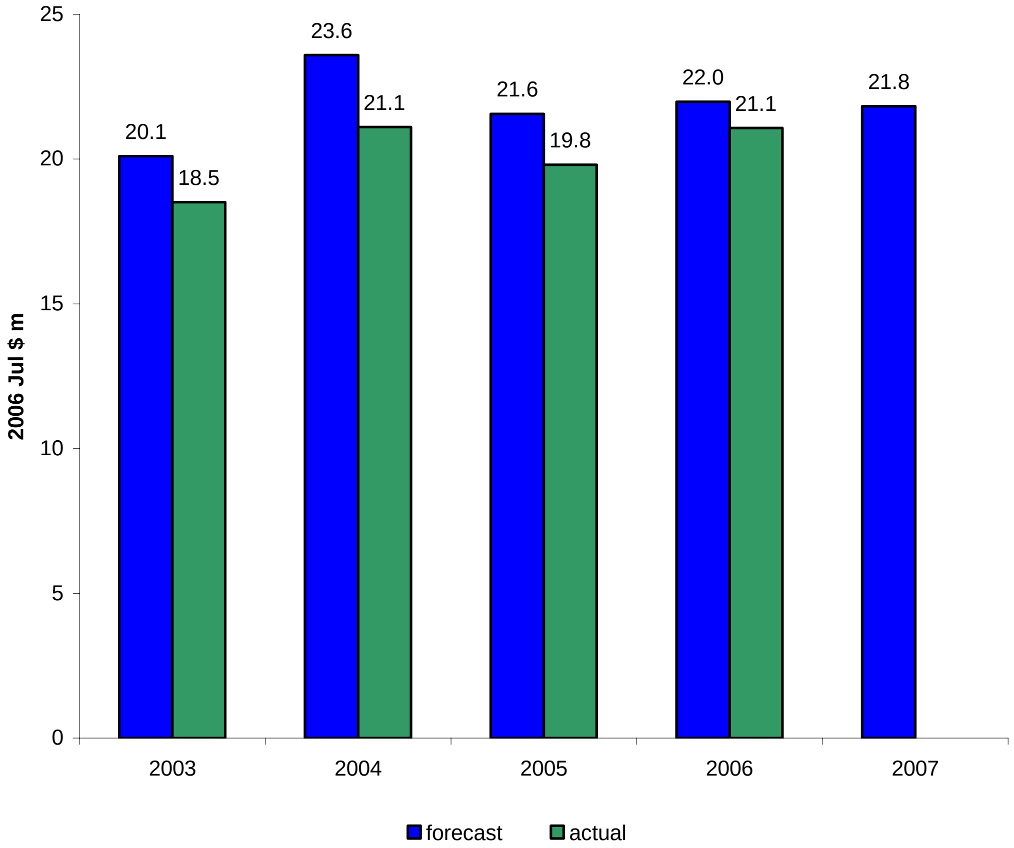
282 Code, s. 8.2(e).

283 Section 2.7 of the code requires the provision of access arrangement information. Section 2.8 allows for certain information to be categorised or aggregated to avoid disclosure of confidential information. It also notes that nothing in s. 2.8 limits the relevant regulator's power under the Gas Pipelines Access Law to obtain information.

Attachment A to the code is reproduced in appendix B of this draft decision.

284 Clause 3.5 of GasNet's second AA was subsequently amended following the Australian Competition Tribunal decision.

Figure 5.1.1: Historical and forecast operating and maintenance costs 2003–07



Source: GasNet, *Submission 2008–12*, pp. 65 and 66.

GasNet submits that this comparison evidences it has been operating more efficiently during the AA2 period than was originally expected. GasNet states, however, that this pattern conceals important trends in certain categories for which GasNet has experienced cost increases.

A comparison of actual and forecast costs disaggregated into direct costs, corporate overheads and fuel costs is set out in table 5.1.1.

Table 5.1.1: Actual and forecast operating and maintenance costs by category

2006 Jul $ m	*2003*	*2004*	*2005*	*2006*	*2007*
Direct opex					
Forecast	10.15	11.17	10.31	11.46	11.22
Actual	9.06	9.34	10.35	11.56	
Overheads					
Forecast	8.52	8.60	8.49	8.76	8.76
Actual	8.18	7.92	7.64	8.14	
Fuel gas					
Forecast	1.43	3.83	2.76	1.76	1.86
Actual	1.27	3.85	1.82	1.38	n/a

Source: GasNet, *Submission*, pp. 65 and 66.

5.1.2.2 Direct operating and maintenance costs

While on average GasNet's direct operating and maintenance costs were below forecast, they have increased over the AA2 period. GasNet submits that the increasing costs are due to the following factors:

- higher demand for skilled labour in the gas industry
- the cost of acquiring and training staff in a highly skilled but relatively narrow sector of the gas industry
- ageing of the PTS assets and
- increasing standards of safety and technical regulation.[285]

5.1.2.3 Corporate overheads

On average GasNet's actual corporate overheads were approximately 7 per cent per annum less than forecast, over the AA2 period. GasNet submits, however, that the analysis 'does not show any significant or sustainable trend in corporate overheads suggestive of ongoing productivity changes or exogenous factors'.[286]

GasNet's corporate overheads decreased between 2003 to 2005 and increased in 2006. GasNet explained that delays in reaching the full complement of corporate staff accounted for this trend. The increase in 2006 costs, include the costs of filling budgeted positions and associated training costs.

5.1.2.4 Fuel costs

GasNet notes that the abnormally high fuel costs incurred in 2004 was the result of unanticipated SEA Gas exports. GasNet submits that fuel use is subject to random exogenous factors such as weather and variations between actual and forecast gas demand.[287]

5.1.3 Proposal

GasNet's proposed non-capital costs for the AA3 period are shown in table 5.1.2.

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[285] GasNet, *Proposed Access Arrangement Submission 2008–12*, 14 May 2007, p. 67.

[286] ibid., p. 68.

[287] ibid., pp. 67 and 68.

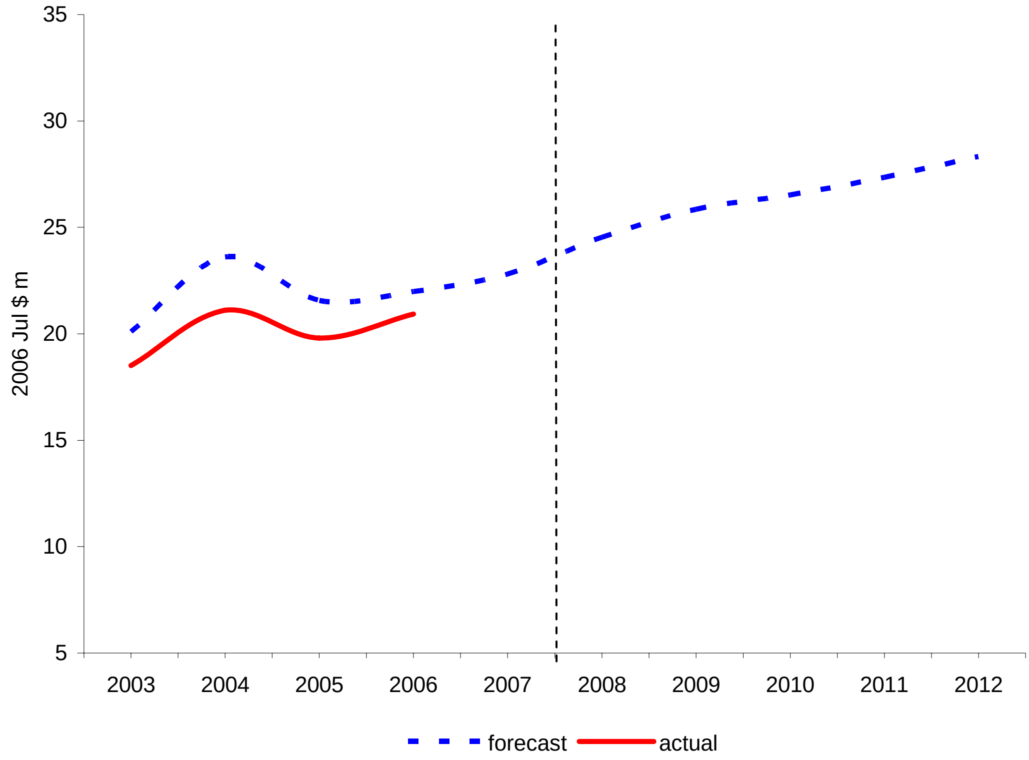
Table 5.1.2: Proposal—non-capital costs

2006 Jul $ m	*2008*	*2009*	*2010*	*2011*	*2012*
Operating and maintenance					
Labour	12.39	13.11	13.58	14.15	14.76
Materials	1.02	1.08	1.10	1.14	1.17
Outside services	3.27	3.55	3.61	3.71	3.81
Fuel gas	2.73	2.88	2.97	3.04	3.18
Other	5.12	5.23	5.27	5.33	5.40
Sub total	**24.53**	**25.85**	**26.53**	**27.35**	**28.33**
Other non-capital costs:					
Benefit sharing	0.90	–0.69	–1.59	–0.85	0.00
Reset costs	0.95	-	-	-	-
K-factor carry over	0.91	-	-	-	-
Asymmetric risk	0.18	0.18	0.18	0.18	0.18
Equity raising costs	0.44	0.50	0.60	0.63	0.61
Other allowances	0.19	0.19	0.19	0.19	0.19
Total non-capital costs	**28.10**	**26.04**	**25.92**	**27.50**	**29.30**

Source: GasNet, *Proposed AAI*, table 3.6.
Note: The figures for 'Fuel gas' and 'Other' in table 3.6 have been incorrectly transposed.

These proposed costs represent a significant increase in costs against that approved for the AA2 period. Significantly, GasNet submits these cost increases are driven by increasing labour costs and operating costs associated with its proposed capex program. The significant increase in GasNet's proposed costs for AA3 over AA2 for the operating and maintenance component of non-capital costs is illustrated in figure 5.1.2.

Figure 5.1.2: Comparison of forecast against actual costs



Source: GasNet, *Submission 2008–12*, pp. 65 and 72.

Clause 7.2(h) of GasNet's second AA provides that the following factors (in addition to the requirements of the code) must be taken into account in calculating the allowable revenue for the operating and maintenance expenditure for the proposed AA:

- the actual operating costs in 2006 adjusted for changes in forecast costs between 2006 and 2007 (but excluding the efficiency gain or loss in 2007)
- forecast changes in workload, taxes, regulatory events, insurance premiums and other relevant costs between 2006 and each year of the third access arrangement period
- a percentage trend factor.

GasNet estimates the base operating and maintenance costs in 2006 at $20.93 m. To arrive at the proposed costs for the AA3 period, GasNet adds 'scope' changes, 'workload' changes and fuel gas costs to arrive at the total forecast operating and maintenance costs for AA3. These are summarised in table 5.1.3.

Table 5.1.3: Proposal—AA3 forecast operating and maintenance expenses

2006 Jul $ m	*2008*	*2009*	*2010*	*2011*	*2012*
Base costs	20.93	20.93	20.93	20.93	20.93
Scope changes	1.51	1.96	2.29	2.63	2.98
Workload changes	0.74	1.47	1.73	2.14	2.62
Fuel gas	1.35	1.50	1.58	1.65	1.80
Total	**24.53**	**25.85**	**26.53**	**27.35**	**28.33**

Source: GasNet, *Submission 2008–12*, p. 64.

Details of these proposed cost changes are outlined in GasNet's submission.[288] Briefly the proposed scope changes relate to technical and safety regulations, legal requirements and other exogenous factors. The proposed workload changes involve costs associated with GasNet's proposed capital expenditure program.

In relation to the trend factor, GasNet submits that its direct operating costs increased by 4.5 per cent in real terms between 2003 to 2006 and considers a similar trend will continue.[289]

5.1.3.1 Benefit sharing allowance for AA3

As shown in table 5.1.4, GasNet proposes the following benefit sharing allowance for AA3.

Table 5.1.4: Proposal—AA3 benefit sharing allowances

2002 Jun $ m		*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*
Forecast (adj)[a]		17.93	21.04	19.23	19.60					
Actual		16.51	18.82	17.67	18.80					
E_t	2003		1.42	1.42	1.42	1.42	1.42			
	2004			0.80	0.80	0.80	0.80	0.80		
	2005				–0.66	–0.66	–0.66	–0.66	–0.66	
	2006					–0.76	–0.76	–0.76	–0.76	–0.76
Total Benefits (B_t)							**0.80**	**–0.61**	**–1.41**	**–0.76**
Total Benefits 2006 Jun $ m							**0.90**	**–0.69**	**–1.59**	**–0.85**

Source: GasNet.

[a] Forecasts taken from table 3.5 of GasNet's current access arrangement information, adjusted for actual inflation, pass-through amounts and revenue from refill tariffs over the AA2 period.

5.1.4 Submissions

The EUCV notes that GasNet's actual costs have been consistently higher than forecasts. The EUCV submits that actual operating costs for the period 2003–06 show some degree of consistency, averaging about $20 m in nominal terms and this should be used as the basis for future operating costs.[290]

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288 GasNet, *Submission*, op. cit., pp. 72–6.

289 ibid., p. 76.

290 Energy Users Coalition of Victoria, *Submission to the issues paper*, 10 August 2007, p. 8.

The EUCV states that there is a relationship between operating and maintenance costs and capital expenditure, particularly for replacement capital expenditure. The EUCV submits that there did not appear to be any corresponding increase in capital expenditure.[291]

Origin Energy generally supports GasNet's contention that the gas industry is facing rising costs. However, Origin Energy questions GasNet's claim that productivity gains have been exhausted and submits that this matter should be investigated in light of potential synergies arising from APA Group's acquisition of GasNet. Origin Energy stated that:

> The extent to which such synergies should be shared between the new owners and consumers is of course a separate matter of public policy.[292]

5.1.5 Assessment

The following assessment of GasNet's proposed non-capital costs will focus firstly on GasNet's proposed operating and maintenance costs. An assessment of the remaining elements of GasNet's proposed non-capital costs will follow.

GasNet proposes substantial increases in operating and maintenance costs over the course of the access arrangement (AA) period. GasNet expects its costs to range from 17 per cent higher than the base year ($20.93 m in 2006) in 2008 in real terms to 35 per cent higher than the base year in 2012.

One of the main drivers is the rise in costs associated with the capital expenditure proposed by GasNet over AA3. Other changes relate to staffing, security and regulatory issues.

The APA Group's acquisition of GasNet in 2006 is likely to have a significant impact on GasNet's non-capital costs over AA3 as the APA Group take advantages of synergies arising from the acquisition. As a consequence, GasNet's corporate overheads would be expected to decrease as the company is incorporated into the APA Group. However, GasNet has made no allowance for any potential cost savings on the basis that at this stage the effect on costs of the acquisition is problematic. Nevertheless, it is the regulator's role to approve only those forecast costs that are the best estimates arrived at on a reasonable basis in accordance with s. 8.2(e) of the code.

The ACCC's approach to its assessment of GasNet's proposed non-capital costs is to assess each of GasNet's proposed scope and workload changes on its merits. An assessment is also made of the overall effect on non-capital costs of the APA Group's acquisition of GasNet. To some extent the increase in costs proposed by GasNet as a result to the scope and workload changes is offset by the ACCC's expected reduction in corporate overheads arising from the acquisition.

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291 ibid., p. 10.

292 Origin Energy, *Submission to the issues paper*, 9 July 2007, p. 9.

5.1.5.1 Scope and workload changes

GasNet's proposed scope and workload changes are shown in detail in table 5.1.5. A consideration of each of these cost items follows.

Table 5.1.5: Proposal—scope and workload changes

2006 Jul $ '000	*2008*	*2009*	*2010*	*2011*	*2012*
Direct opex					
Operating procedures	60	60	60	60	60
Security upgrades	135	180	180	180	180
Risk assessment of pipelines	26	26	26	26	26
Infrastructure patrols	60	60	60	60	60
Odorant	71	73	74	76	78
Ageing workforce	150	232	232	232	232
Hazardous area review	80	80	80	80	80
Sub-total	**581**	**710**	**712**	**714**	**716**
Overheads					
IT costs	66	66	66	66	66
Regulatory accountant	130	130	130	130	130
Risk manager	115	115	115	115	115
Sub-total	**311**	**311**	**311**	**311**	**311**
Both					
Labour cost	615	935	1 264	1 602	1 950
Total scope changes	**1 507**	**1 956**	**2 287**	**2 627**	**2 977**
Workload changes					
Pipelines	164	210	411	411	453
Regulated facilities	580	1 261	1 321	1 729	2 165
Total workload changes	**744**	**1 471**	**1 732**	**2 140**	**2 617**
Total changes	**2 251**	**3 427**	**4 019**	**4 767**	**5 594**

Source: Modelling provided by GasNet to the ACCC.

The ACCC commissioned Ross Calvert Consulting (RCC) to report on GasNet's proposed scope and workload changes.[293] In general, RCC agrees with GasNet that its operating and maintenance expenses are likely to rise over the upcoming AA period, and supports most of GasNet's proposals. Full details of RCC's analysis and conclusions are contained in RCC's report. The ACCC supports GasNet's proposed scope and workload changes except where indicated.

Interested parties did not comment on each individual item of GasNet's proposed changes to its operating and maintenance costs. However, Origin Energy generally agreed with GasNet that the gas industry is facing rising costs.[294]

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293 Ross Calvert Consulting, *GasNet Access Arrangement—Assessment of Proposed Operating Expenditure Scope and Workload Changes*, September 2007.

294 Origin Energy, op. cit., p. 9.

5.1.5.2 Changes in labour costs

GasNet proposes a real increase in labour costs of 2.8 per cent per annum. GasNet has relied on a report by BIS Shrapnel which forecast real wages growth in the electricity, gas and water sector of 2.8 per cent annum over the six year period 2007–08 to 2012–13, which roughly corresponds to the AA3 period for GasNet (1 January 2008 to 31 December 2012).[295]

Other reasons put forward by GasNet to support its claim for higher labour costs are:

- it was noted in the Commonwealth Treasury Budget 2006–07 that the Wage Price Index is forecast to increase by 4 per cent in 2006–07
- a shortage of skilled labour in the electricity, gas and water sectors in recent years, which is expected to be exacerbated by some utilities embarking on increased maintenance and refurbishment programs and
- wage increases in electricity, gas and water sectors well above national average over the past six years.[296]

As part of its draft decision for SP AusNet's 2008–09 to 2013–14 electricity transmission proposal, the AER commissioned Econtech to report on forecast labour costs.[297] Actual annual growth rates in labour costs for the electricity, gas and water sector in Victoria between 1995–96 and 2005–06 and Econtech's forecasts for 2006–07 to 2015–16 are shown in table 5.1.6.

Econtech attributes the volatility in the annual rates partly to cyclical factors that affect the forecasts.

Table 5.1.6: Labour cost growth rates, Victoria, 1995–96 to 2015–16

%	*Actual electricity, gas and water*	%	*Forecast electricity, gas and water*
1995–96	3.9	2006–07	1.8
1996–97	3.4	2007–08	5.9
1997–98	9.0	2008–09	6.0
1998–99	0.2	2009–10	7.6
1999–00	11.8	2010–11	7.0
2000–01	6.6	2011–12	6.2
2001–02	7.5	2012–13	5.9
2002–03	1.0	2013–14	5.6
2003–04	–2.0	2014–15	5.0
2004–05	2.8	2015–16	4.7
2005–06	4.1		

Source: Derived from Econtech, *Labour Costs Growth Forecasts*, 13 August 2007, table 6.4.

RCC reviewed Econtech's report and notes that:

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295 GasNet, *Operating and Maintenance Expenditure Scope and Work Load Changes 2008 to 2012*, April 2007, p. 5 (GasNet, *Submission*, op. cit., attachment D).

296 ibid., p. 5.

297 Australian Energy Regulator, *Draft Decision: SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007.

> Econtech's forecasts of both national wage inflation and wages growth in the electricity gas and water sector were quite similar to that of BIS Shrapnel.[298]

On the basis of the work done by Econtech, RCC concludes that GasNet's forecast of a 2.8 per cent per annum real increase in labour costs over AA3 is reasonable.[299]

The evidence presented to the ACCC points to labour costs in the gas sector increasing a rate above inflation during AA3. The only difference is the level of the increase in labour costs. Given the uncertainty surrounding the prediction of future events, such differences can be expected in statistical forecasting when assumptions need to made regarding input variables. Any differences in the forecast numbers neither invalidate the analysis nor necessarily indicate that any particular methodology is superior to another.

In summary, GasNet justifies an increase in labour costs above the forecast inflation rate and its proposal of a real increase of 2.7 per cent is considered reasonable.

Of the total proposed scope change of $1.507 m in 2008, $0.651 m is attributed to increased labour costs.

5.1.5.3 Review and update of operating procedures

GasNet proposes $60 000 per annum to cover the periodic review and update of its operating procedures. GasNet has submitted that the cost is warranted to comply with recent changes to health and safety legislation, the *Pipelines Act 1967* (Vic) and recent and proposed changes to Australian Standard (AS) 2885. The work involves GasNet:

- drafting 400 new policies and procedures to ensure GasNet is up to date and
- reviewing 1000 policies and procedures every three years (around 330 per annum).[300]

To undertake this work GasNet intends to employ one additional technical manager with responsibility across both the pipelines and facilities management area.

RCC reviewed GasNet's proposal and concludes that GasNet has demonstrated the need for this work and the cost claimed was reasonable.

5.1.5.4 Security upgrades of key facilities and pipelines

For this item GasNet proposes $135 000 for 2008 and $180 000 thereafter. The amount of $180 000 comprises:

- Three visits per year to check security equipment: $85 000
- Upgrading of site lighting at about nine sites: $20 000

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[298] Ross Calvert Consulting, op. cit., p. 3.

[299] ibid., p. 3.

[300] GasNet, *Operating and Maintenance Expenditure Scope and Work Load Changes*, op. cit., p. 7.

- Cost of staging an emergency exercise: $20 000
- Additional support from a security firm: $55 000
  (including response to alarms on site)

GasNet submits that the additional expenditure is required in order for GasNet to meet its obligations under the *Terrorism (Community Protection) Act 2003* (Vic).[301] As the PTS has been declared an essential service under that legislation, GasNet has certain obligations, including:

- preparation of a risk management plan
- auditing and updating the plan annually and
- preparation and participation in training exercises.

GasNet's proposal is in response to an external audit of its risk management plan which GasNet commissioned in 2006. RCC reviewed GasNet's proposal. In relation to the proposed $20 000 for the staging of an emergency exercise, GasNet states that it does not have the expertise to conduct the exercise and intends to bring in an external expert.[302] RCC queried this statement given GasNet's general policy of favouring in-house expertise.[303] Nevertheless, RCC sees value in having the company's performance assessed independently by a consultant. RCC considers that the cost of $20 000 is reasonable.

GasNet's proposed costs of $85 000 for site visits to check security equipment is based on actual costs for 2006 of $3 400 per visit plus and allowance for cherry picker hire and travelling time, and greater complexity of the new systems. RCC notes that seven sites visited three times a year would alone cost $71 500, before the additional allowance is included. RCC considers GasNet proposed costs are reasonable.

RCC notes that a security firm currently makes daily visits to the Dandenong site and Brooklyn and Gooding compressor stations at an annual cost of $45 000 and that the Brooklyn and Gooding sites are not currently alarmed. RCC considers reasonable the additional costs proposed by GasNet of $55 000 to cover nightly as well as daylight visits and to respond to alarms.

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301 As part of its draft decision for Envestra's proposed revisions to its access arrangement, the Essential Services Commission (ESC) assessed and proposed to disallow Envestra's proposed $0.17 m for an item 'Infrastructure protection and risk management'. This has similarities to GasNet's proposal as both are primarily in response to the introduction of the *Terrorism (Community Protection) Act 2003* (Vic). However, Envestra's proposal differs in a number of respects to GasNet's proposal. Notably, Envestra appears to rely on a report it commissioned in 2003, and the ESC accordingly questioned the necessity of the work in the 2008–12 AA period: see Essential Services Commission, *Gas Access Arrangement Review 2008–2012: Draft Decision*, 28 August 2007, pp. 193–95.

In contrast, GasNet's proposal is in response to a report it commissioned in 2006.

302 GasNet, *Operating and Maintenance Expenditure Scope and Work Load Changes*, op. cit., p. 9.

303 ibid., p. 17.

RCC considers GasNet's proposed costs of $20 000 to upgrade lighting at nine sites is reasonable, noting that the cost is estimated to cover on average 5 kW per site.

5.1.5.5 Risk assessment of pipelines

GasNet proposes additional operating expenditure of $25 600 per annum to undertake integrity assessments of the PTS, as required by AS 2885. AS 2885 requires maximum allowable operating pressure (MAOP) assessments at intervals not exceeding five years. GasNet expects that it will require MAOP assessments for about eight pipelines per annum at an estimated time of five days per assessment.

GasNet submits that the additional $25 600 represents a scope change because GasNet did not undertake any assessments in 2006 as no assessments were due.

RCC considers that the amount of $25 600 is reasonable, but questioned whether GasNet has made the case that the work was additional to what GasNet was required to undertake. Nevertheless, RCC notes that the AS 2885 is now more prescriptive than previously and will require more time to complete the task. Accordingly RCC supports GasNet's proposal.

5.1.5.6 Increased costs for infrastructure patrols

GasNet submits that when a disturbance by an external party occurs near GasNet's network a GasNet employee will attend the site while the work is being undertaken to ensure that the work does not place the pipeline at risk (in accordance with AS 2885.3).

GasNet states that the workload of pipeline patrollers has increased significantly because of growing construction activity in metropolitan areas due to metropolitan centres expanding and growth of high density areas within metropolitan centres. Accordingly, GasNet submits that an additional pipeline patroller is required at a cost of $60 000 per annum. RCC considers that GasNet's proposal is reasonable.

5.1.5.7 Increased compliance costs

GasNet submits that it intends to employ a regulatory accountant at a cost of $60 000 per annum to handle the expected additional workload arising from changes to the national gas law. GasNet expects that it will have to submit its regulatory accounts to external audit under the new rules at a cost of $30 000 per annum.

RCC notes that to a certain extent the functions that would be undertaken by the regulatory accountant would already be undertaken by GasNet in accordance with the code. On the other hand RCC states that the new gas law may involve an increase in the workload of regulated entities and the expense may be justified. As RCC points out, however, the third AA for the PTS will commence before the new law comes into affect. Consequently the new gas law is unlikely to be applicable to AA3.

The changes to the national gas law will increase the reporting requirements of service providers. One means of addressing this issue is the approach proposed by GasNet. There is merit in appointing a dedicated regulatory accountant as this should lead to the production of timely, accurate, meaningful and comprehensive information. This in turn will aid the regulatory decision-making process. However, the new gas law and transitional rules have not yet been finalised. Given that the new gas law will not apply to GasNet for AA3, it is uncertain at this stage whether the AER will have the power to apply the new information gathering and reporting requirements to GasNet before the AA4 period. Accordingly, for the purposes of this draft decision the ACCC does not propose to approve the costs of a regulatory accountant for each year of AA3. Instead, the ACCC proposes to approve the costs only for the final year (2012) to allow GasNet time to prepare for the application of the new gas law for AA4. The situation may become clearer, however, before the ACCC releases its final decision and the ACCC will reconsider this matter before then in light of any new developments.

GasNet has submitted that there is a need for a new role of an Enterprise Risk Manager to comply with the requirements of the *Financial Services Reform Act 2001* (Cth) Compliance Plan (dated 2003). GasNet states this plan requires certain responsible officers to complete monthly and quarterly checklists and ensure that an internal bi-annual audit and external audits of compliance are conducted.[304]

GasNet further states that each of GasNet's departments has responsibility for complying with their various obligations, much of which is not audited. The appointment of an Enterprise Risk Manager will ensure a holistic approach with more comprehensive reporting and checking. GasNet submits that the role is also required because of the significant legal obligations placed on GasNet.

The expected cost of $140 000 was based on market remuneration data for the utilities sector prepared by Geoff Nunn and Associates in association with the National Remuneration Centre (April 2006).

RCC considers that GasNet's approach is an efficient and effective means of ensuring compliance with its numerous complex legal obligations. RCC considers that GasNet's proposed annual expenditure of $140 000 is reasonable.

While the ACCC agrees with RCC that GasNet's approach is reasonable, it is concerned that GasNet is merely streamlining existing procedures and the additional $140 000 would be offset by cost savings due to increased efficiency. Nevertheless, GasNet puts forward some arguments to suggest that the costs may be additional. These arguments include:

- There has been a significant growth of legal obligations placed on GasNet. For example, Australian Accounting Standard B7, which was introduced in August 2005 and applies to GasNet from 1 January 2007.
- The new position will involve more comprehensive reporting and checking than is currently carried out.[305]

304 ibid., p. 15.

305 ibid., pp. 15 and 16.

On balance the ACCC considers that the appointment of an Enterprise Risk Manager is associated with an increased workload. Accordingly, the ACCC considers that GasNet's proposed costs represent additional costs and are reasonable.

5.1.5.8 Measures to counter the effect of an aging workforce

GasNet submits that it is facing a shortage of skilled labour and engineering support, which is exacerbating the problems associated with an aging workforce. To address this issue GasNet intends to expand its recruitment of new graduates and apprenticeship program at an additional cost of $150 000, with an associated increase in training costs of $82 000 (based on a cost of $1 500 per course).[306]

RCC has reviewed GasNet's proposal and concludes that it is reasonable. RCC notes that pipeline engineering is a highly specialised profession requiring considerable on the job training in addition to the basic skills acquired at tertiary institutions. RCC also states that as GasNet is a relatively small company little opportunity currently exists for new recruits to rotate between jobs during their training period. Hence a new employee will have to work alongside an incumbent to gain the critical job skills. Accordingly, RCC concludes that GasNet's claim of $150 000 over AA3 for its graduate recruitment and apprenticeship program is reasonable.

RCC also considers GasNet's proposed additional training costs of $82 000 over AA3 to be reasonable, taking into account current rates charged for training courses and associated travel and accommodation costs in some instances.[307]

5.1.5.9 Increased cost for odorant

GasNet advises that its cost of odorant increased by 20 per cent from 1 January 2007 and that its supplier advises that a further increase will follow later in 2007. GasNet expects that this increase will be in the order of 20 per cent. Reasons given for the increase in costs are the closure of one of three global production facilities and a shortage of odorant.

When the increased cost of odorant is coupled with the increased volumes of odorant in line with higher gas sales, the total cost for odorant is expected to rise from $151 536 in 2006 to $229 599 in late 2007.

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306 ibid., pp. 19 and 20. GasNet quotes a figure of $100 000 over the AA3 period to cover both regulated and unregulated assets whereas the $82 000 only relates to regulated assets.

307 As part of its draft decision for Envestra's proposed revisions to its access arrangement, the ESC assessed and proposed to disallow this item for Envestra. Briefly, the ESC reasoned that the concept of an aging workforce is not new and Envestra ought to take it into account as part of its ongoing operations and a scope change is accordingly not justified. Envestra is a large organisation compared with GasNet and may be able to manage the costs of an aging workforce on an ongoing basis and smooth the costs over an extended period. However, relatively small organisations such as GasNet may not have this option. Instead action may need to be taken irregularly and the costs are likely to be lumpy: see Essential Services Commission, op. cit., pp. 201–203.

RCC notes that the cost of odorant is beyond GasNet's control and the magnitude of the expected increase is uncertain. In view of this uncertainty RCC recommends that the increase in odorant costs should be treated as a pass-through event.

While there may be merit in treating the increase in odorant as a pass-through given the level of uncertainty, the ACCC proposes to accept GasNet's proposal, given that the expected increase in costs (in the order of $70 000) is not substantial in terms of GasNet's overall operating costs. If the exact magnitude of the increase becomes known between the time of the release of this draft decision and the release of the Final Decision, an appropriate adjustment will be made.

5.1.5.10 Information technology costs

GasNet estimates increased information technology (IT) costs totalling $80 000 comprising:

- $50 000 for the ongoing operation of an IT disaster recovery centre to be set up in Brooklyn and
- $30 000 to upgrade the communications to GasNet's compressor sites from the current low speed DDN (Serial) system to a Frame Relay (IP) based network in 2007.

RCC considers that GasNet's proposed IT disaster recovery centre is reasonable. According to RCC a prudent pipeline owner would adopt these measures in order to minimise disruption to the transmission system and its customers in the event of an IT disaster. RCC also considers that the cost of $50 000 is reasonable in order to maintain the centre.

RCC considers that the additional cost of $30 000 to upgrade the communications to compressor sites is reasonable, noting that the existing technology is outmoded and the greater complexity of new or upgraded compressor stations involves the transmission of much more data than the older stations.

While establishment costs will be incurred to upgrade to an IP-based system, efficiencies would be expected from this system compared with a DDN service.

5.1.5.11 Hazardous area review

GasNet has submits that certain regulations require its hazardous area installations to comply with installation standards. GasNet intends to undertaken a hazardous area inspection project. This will involve the production of a verification dossier for each of GasNet's sites that have electrical equipment located within the hazardous areas. This work will involve detailed field inspections and documentation of all the electrical equipment.

GasNet expects that this work will require a full time employee at a cost of $80 000 per annum. RCC notes that GasNet has provided limited information, but understands that 20 regulator sites and five compressor stations would be involved. RCC has reviewed GasNet's proposal and considers that GasNet's assessment of the workload appears to be excessive. Accordingly, RCC considers an amount of

$40 000 would be more appropriate. The ACCC proposes to accept RCC's recommendation.

5.1.5.12 Summary of scope changes

A summary of the scope changes proposed by the ACCC is contained in table 5.1.7.

Table 5.1.7: ACCC proposed scope changes

	2008	*2009*	*2010*	*2011*	*2012*
Operating procedures	60.0	60.0	60.0	60.0	60.0
Security upgrades	135.0	180.0	180.0	180.0	180.0
Risk assessment of pipelines	25.6	25.6	25.6	25.6	25.6
Infrastructure patrols	60.0	60.0	60.0	60.0	60.0
Odorant	71.0	73.0	74.0	76.0	78.0
Aging workforce	150.0	232.0	232.0	232.0	232.0
Hazardous area review	40.0	40.0	40.0	40.0	40.0
IT costs	60.0	60.0	60.0	60.0	60.0
Regulatory accountant	0.0	0.0	0.0	0.0	130.0
Risk ,manager	140.0	140.0	140.0	140.0	140.0
Total	**741.6**	**870.6**	**871.6**	**873.6**	**1 005.6**

Source: ACCC analysis.

5.1.5.13 Workload changes—direct operating costs (pipelines)

GasNet proposes additional amounts ranging between $160 000 in 2008 to $420 000 in 2012 to cover the costs of maintaining the extra length of pipeline (in accordance with GasNet's proposed capital expenditure). The ACCC requested RCC to comment on GasNet's proposed additional costs. GasNet's proposed costs compared with those recommended by RCC are shown in table 5.1.8.

Table 5.1.8: Workload changes—direct operating costs (pipelines)

2006 Jul $ m	*2008*	*2009*	*2010*	*2011*	*2012*
GasNet	0.160	0.210	0.410	0.410	0.450
RCC	0.080	0.166	0.189	0.189	0.189

Source: Ross Calvert Consulting, p. 7.

RCC's recommended costs differ from those proposed by GasNet for the following reasons:

- RCC has omitted the operating costs associated with the Carisbrook, Ballarat and Sunbury loops on the basis that the ACCC is unlikely to approve these facilities for the AA3 period.
- Looping of the Wollert to Wodonga pipeline is a more cost effective alternative than the Euroa Compressor Station proposed by GasNet.
- Operating costs are lower for looping than new pipelines (about 75 per cent of the costs of new pipelines).

The ACCC accepts these recommendations and proposes to reduce the costs proposed by GasNet accordingly.

5.1.5.14 Workload changes—direct operating costs (compressors, regulators and heaters)

GasNet submits that the total replacement cost of compressor stations drives the operating and maintenance costs of the stations. GasNet’s proposed capital works program includes refurbishment of its existing compressor stations and construction of new stations at Euroa and Stonehaven.

RCC notes that GasNet is seeking a doubling of the allowance for compression maintenance. GasNet’s proposed costs compared with those recommended by RCC are shown in table 5.1.9.

Table 5.1.9: Workload changes (compressors)

2006 Jul $ m	*2008*	*2009*	*2010*	*2011*	*2012*
GasNet compressors	-	0.52	0.52	0.87	1.24
RCC compressors	-	0.10	0.10	0.10	0.10

Source: Ross Calvert Consulting, pp. 8 and 9.

RCC identifies several factors that will have an impact on the maintenance costs of compressors, some of which will have the effect of increasing costs, whereas others will have the effect of reducing costs. RCC states the greater size and complexity of the compressor units will tend to increase the time required for maintenance.

On the other hand better control and communications data and improved station design should have the opposite effect. Moreover, RCC discounted GasNet’s costs on the assumption that neither the Stonehaven nor the Euroa stations will be approved by the ACCC as prudent expenditure during the AA3 period.

RCC notes that no additional labour costs at the Gooding, Springhurst and Iona stations could be justified because the number of units at each station is unchanged. Offsetting the greater size and complexity at the Wollert and Brooklyn stations is a reduction in the number of units. Hence the impact on labour requirements is neutral and no additional labour costs are justified.

Overall RCC considers that the increased size and complexity of a number of compressor units justifies an additional allowance for materials and services.

A comparison of GasNet’s proposed cost increases for heaters and regulators compared with RCC’s recommendations are shown in table 5.1.10.

Table 5.1.10: Workload changes (regulators and heaters)

	2008	*2009*	*2010*	*2011*	*2012*
GasNet heaters/regulators	0.58	0.74	0.80	0.86	0.93
RCC heaters/regulators	0.42	0.54	0.58	0.63	0.68

Source: Ross Calvert Consulting, pp. 9 and 10.

RCC notes that GasNet estimates the costs of maintaining new and upgraded regulators and heaters by determining the relationship between the ORC and the costs of maintaining the facilities in 2006. GasNet calculates this ratio at 4.81 per cent. GasNet then applies this same ratio to the new and upgraded facilities to justify additional maintenance costs. In RCC’s view the ratio of

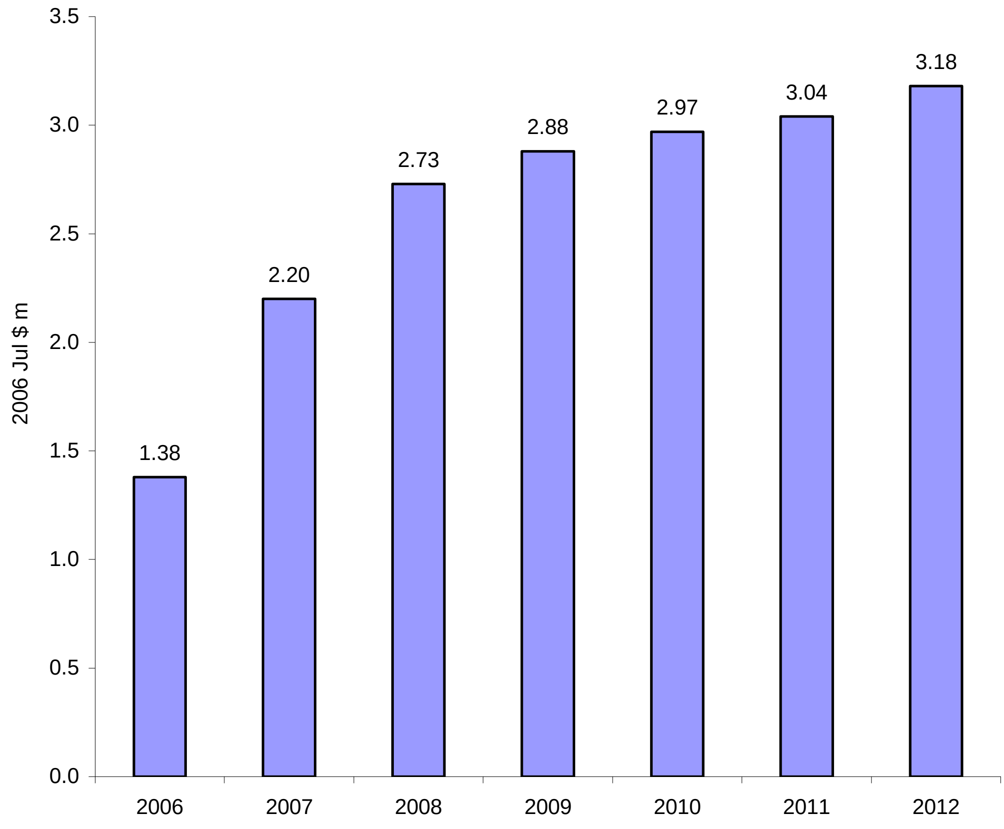
4.81 per cent is overstated because of recent escalation in the cost of installing these facilities. RCC considers that a ratio of 3.5 per cent is appropriate.

5.1.5.15 Fuel gas

GasNet's actual fuel gas costs for 2006 and forecast fuel costs for 2007 to 2012 are shown in figure 5.1.2. GasNet provides gas for compressors and heater operations. Fuel gas is purchased at market rates and is a significant element of GasNet's operating costs. GasNet is forecasting a substantial increase in fuel gas costs over actual costs incurred in 2006, almost doubling between 2006 and 2008.

GasNet submits that the main drivers behind the increase in fuel cost are: an increase in forecast volumes; higher gas prices (GasNet has forecast a 10 per cent increase); refill of underground storage; and gas exports.

Figure 5.1.2: Proposal—fuel gas costs (actual 2006, forecast 2007–12)



Source: GasNet, *Submission 2008–12*, pp. 65 and 75.

RCC has reviewed GasNet's forecast fuel gas costs. Rather than including fuel gas costs in the calculation of reference tariffs, as proposed by GasNet, RCC recommends that fuel gas costs be treated as a pass-through event. In recommending this course of action RCC notes that, while forecasting annual use of fuel gas in the PTS could be predicted in the past with reasonable certainty, this task is increasingly difficult for the next five years for the following reasons:

- the shift in the production mix as the traditional dominance of Gippsland gas weakens, with a significant part of Victoria's gas demand now sourced from the Otway and Bass Basins
- the move to four hour trading intervals during the gas day can create the potential for constraints in the eastern part of the system, which VENCorp manages by moving Longford gas into the Southwest pipeline using compression at Gooding and Brooklyn
- the increasing use of gas as a fuel for electricity generation, which has a significant effect on compressor fuel use and
- changes in the composition of compression capacity as older compressor stations are progressive refurbished and larger engines installed.

In relation to GasNet's forecast 10 per cent price increase in the price of gas, RCC states that although GasNet's forecast is highly speculative it is not unreasonable in light of recent increases in the price of gas.

RCC identifies the following factors as relevant to the ACCC's consideration of how to deal with the uncertainty in forecasting GasNet's fuel gas costs:

- the extensive changes expected to occur in compressor fuel use
- the extreme volatility of fuel usage in an environment with increasing use of gas-powered generation
- the magnitude of the costs involved and
- GasNet has little control over compressor fuel usage.

The ACCC is not satisfied that GasNet's forecast fuel costs meet the tests in ss. 8.2(e) and 8.37 of the code. Given the potential volatility of fuel gas costs, RCC recommends that fuel gas costs be treated as a pass-through event. RCC also recommends that GasNet should be required to seek tenders for the supply of its fuel gas requirements to safeguard the interests of users.

By including forecast fuel gas costs in its proposed operating costs, GasNet is prepared to bear the risk of actuals deviating from forecasts. Nevertheless, if actual costs prove significantly higher than forecast, GasNet has the option of submitting revisions to the AA with the view to increasing reference tariffs to cover the higher costs. On the other hand, if fuel gas costs prove to be significantly less than forecast, GasNet will retain the difference rather than the lower costs being passed on to users through lower reference tariffs.

Given the potential volatility in fuel gas costs and the significance of this item, the ACCC supports RCC's recommendation that this item be treated as a pass-through. This approach effectively passes the risk of actual fuel gas costs deviating from forecasts from GasNet to gas users. This raises the issue of whether the inclusion of fuel gas costs as a pass-through event acts as a disincentive to GasNet to minimise its fuel gas costs. However, as RCC notes, fuel gas usage is outside the control of GasNet since VENCorp is the system operator. Moreover, requiring GasNet to tender for its fuel gas requirements, as recommended by RCC, would address any pricing concerns. Under this approach it would make no difference whether fuel gas costs are included as a pass-through event or included in GasNet's forecast costs. It is worth noting that GasNet has excluded fuel gas costs from its carryover efficiency mechanism, reflecting that fuel gas costs are largely outside GasNet's control.

The ACCC proposes to include the base year's (2006) fuel gas costs in GasNet's forecast operating and maintenance costs and any changes to be treated as a pass-through event. The ACCC also proposes to impose a condition on GasNet that it must tender for its fuel gas requirements. GasNet has informed the ACCC its current contract for fuel gas expires in 2008 and it anticipates that the new contract will be tendered out. The ACCC considers that such an approach is one that would be adopted by a prudent service provider acting efficiently, and complies with s. 8.37 of the code.

A proposed amendment is included in chapter 5.2 of this draft decision covering pass-through events.

5.1.5.16 Allocation of costs between regulated and unregulated assets

In calculating its forecast costs GasNet allocates 88.18 per cent of its overheads to the regulated assets. This is based on the mix of regulated and unregulated assets at the commencement of AA2. GasNet's justification is that as 2006 is used as the base year for forecast costs for the period 2008–12, and as 88.18 per cent of actual overheads were allocated to the regulated assets for that year, it is appropriate that the same allocation factor should be used for forecast costs.[308]

The acquisition of GasNet in October 2006 by the APA Group will lead to some corporate restructuring, which has not been reflected in GasNet's proposed costs. GasNet advises that the effect of this on GasNet's overheads is problematic at this stage and proposes to retain the existing allocation for AA3.

By omitting the effect of the APA Group's acquisition of GasNet on its corporate costs, GasNet is effectively assuming that any cost savings to the APA Group will be offset on a one-for-one basis by the allocation of a proportion of the APA Group's corporate overheads to GasNet. Unless this approach produces forecast costs that are the best estimates arrived at on a reasonable basis, it would not be consistent with s. 8.2(e) of the code. However, because of synergies it seems likely that the effect of the restructure will lead to lower overheads than currently incurred by GasNet being allocated to GasNet by the APA Group.

An approach more consistent with the code, in the ACCC's view, would be to forecast the direct overheads attributed to GasNet (such as the costs of maintaining an office in Victoria) and to allocate to GasNet a proportion of the APA Group's overall corporate overheads on a reasonable basis.

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[308] GasNet, *Email to the AER*, 22 June 2007.

The APA Group's current approach is to allocate its corporate overheads on the basis of an asset's contribution to the APA Group's total revenue.[309] In relation to its proposed revisions to the AA for the Roma to Brisbane pipeline (RBP) in 2006, the APA Group allocated 14 per cent of its indirect corporate costs to the RBP on the basis that the RBP contributed 14 per cent of the APA Group's revenue (in 2005). A similar approach was adopted by the APA Group for the Moomba to Sydney pipeline (MSP).

GasNet's proposed overheads for the PTS are considerably higher than the overheads approved by the ACCC for the RBP and the MSP. When a portion of VENCorp's overheads are added to GasNet's to enable a proper comparison to be made the difference is even more significant.

Based on the information available, the ACCC estimates that the reduction in GasNet's overheads could range from $2 m to $4 m per annum.[310]

The ACCC's analysis does not take into account recent acquisitions by the APA Group, such as the Allgas gas distribution business in Queensland. Accordingly, the contributions from RBP and MSP to the APA Group's total revenue would have decreased from 14 per cent and 50 per cent respectively. Therefore, because of the existence of synergies, it seems likely that the overhead costs allocated to the RBP and MSP would also have fallen in real terms, despite the fact that the APA Group's total corporate overheads may have increased. In other words the potential reduction in overheads that GasNet may achieve could be in excess of the $2 m to $4 m range.

The ACCC proposes to reduce GasNet's forecast corporate overheads by $2 m. The allocation of corporate overheads could be calculated by a number of methods. The ACCC has considered the available information and is of the view that the method it has used provides the best estimate arrived at on a reasonable basis as required by the code. To the extent that GasNet is able to achieve greater reductions it will retain the difference during the AA3 period as part of its incentive mechanism.

5.1.5.17 Conclusion on operating and maintenance costs

The above analysis focussed on the operating and maintenance costs component of GasNet's proposed non-capital costs. The ACCC considers that GasNet's has overestimated its operating costs for 2008–12. Accordingly, GasNet's forecast costs are not the best estimates arrived at on a reasonable basis in accordance with s. 8.2(e) of the code.

A comparison of GasNet's proposed operating and maintenance with those proposed by the ACCC is shown in figure 5.1.3 (fuel gas costs are excluded). The difference in costs range between an 8 per cent reduction in 2008 to a 15 per cent reduction in 2012.

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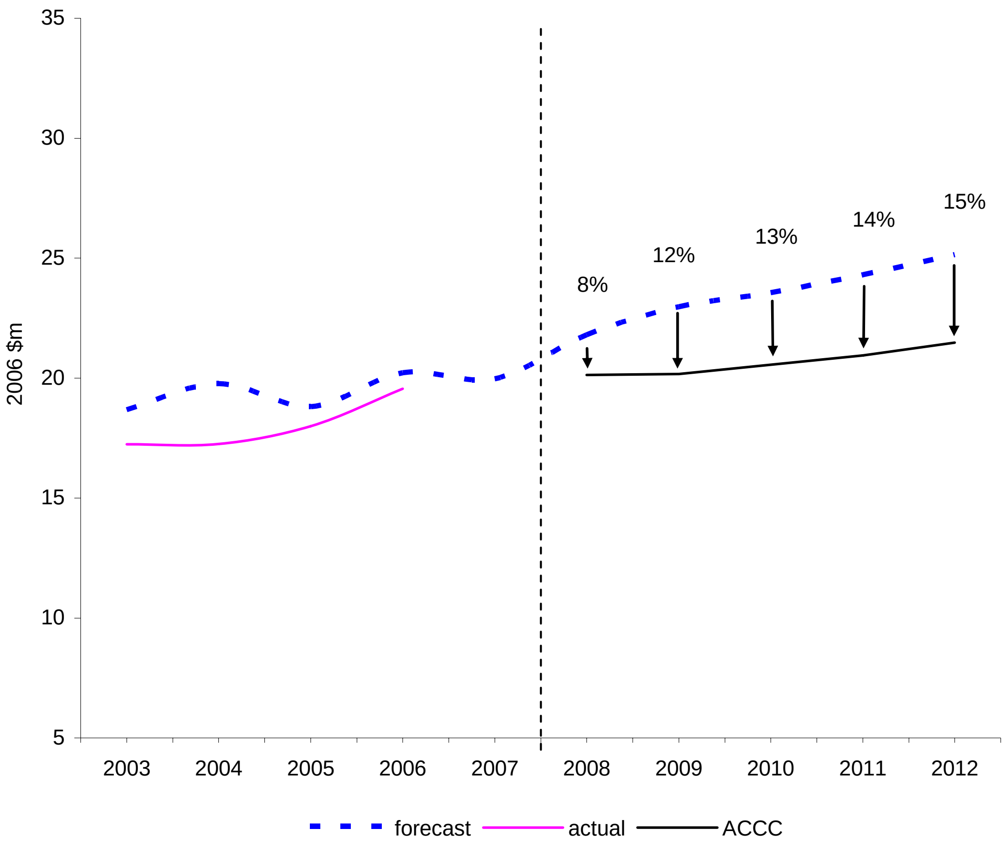
[309] The APA Group's annual ring fencing reports confirm that revenue shares are used as the basis for allocating corporate overheads.

[310] The ACCC's analysis is based on confidential information of the APA Group's overheads which was provided to the ACCC during its assessment of the RBP and MSP access arrangements.

Figure 5.1.3: Difference between GasNet and ACCC proposed operating costs



5.1.5.18 Benefit sharing allowance for AA3

The ACCC has reviewed GasNet's calculations and considers they are generally in accordance with the current AA provisions, although notes that GasNet has used forecast cost categories and values from table 3.5 of its AAI (rather than table 3.6), although this does not affect the calculation. GasNet has not escalated the value of carryover amounts from June to December 2006 dollars when calculating its revenue requirement which will need to be rectified.

5.1.5.19 Regulatory costs

GasNet proposes total regulatory costs (reset costs) of $950 000 for AA3, compared with $1.05 m approved by the ACCC for AA2. GasNet has provided the ACCC with confidential information containing details of the actual costs of each of its consultants and legal adviser. On the basis of the material provided to the ACCC the work involved is commensurate with the work involved in preparation for AA2. Accordingly, costs in the order of $950 000 appear reasonable

5.1.5.20 K-factor carryover

GasNet's second AA includes a provision for a K-factor adjustment as part of the transmission price control formulae for annual tariff adjustments. The K-factor adjustment allows for an increase (decrease) in the maximum average tariff (above or below the CPI–X formula) in the year following an under-recovery (over-recovery) of actual revenue/GJ relative to the allowed revenue/GJ. However, the limitation on annual increases in individual tariffs of 2 per cent restricts the amount of any shortfall in average revenue/GJ that GasNet can recover in AA2. Accordingly, any unrecoverable K-factor in AA2 is carried over to AA3. This is in accordance with the fixed principle as approved for AA2. The K-factor carryover allowance is to be based on actual figures (or estimates where actual figures are not available). GasNet submits a carryover K-factor allowance of $909 768 for AA3. However, this allowance only relates to the K_{tb} amount for 2006 and a best estimate of the KT_a for 2007 will need to be submitted by GasNet between the draft and final decision. GasNet suggests that it is appropriate to provide its best estimate of the KT_a at the same time as its best estimate for inflation and the period for calculating the risk free rate.[311] In addition, the KT_a factor will be updated in AA3 when the actual KT_a for 2007 is known and an adjustment for any difference between the best estimates and the actual carryover for will be reflected in tariffs in accordance with GasNet's fixed principle.

5.1.5.21 Labour capitalisation

Given the extensive capital expenditure program proposed by GasNet, the ACCC was concerned that GasNet may be double-counting by capitalising some labour costs and also included them in its proposed operating and maintenance costs. GasNet has informed the ACCC, however, that there is no double-counting as labour costs have been proportion between the capital and non-capital cost components. GasNet further stated that external contractors would be employed should additional work be required.

5.1.5.22 Asymmetric risk

A comparison of the allowances for asymmetric risk in AA2 period compared with the allowances proposed by GasNet for AA3 is shown in table 5.1.11.

Table 5.1.11: AA2 and proposed AA3 annual allowance for asymmetric risks

2006 Jul $ m	*AA2*	*Proposed AA3*
Insurer credit risk	2 000	1 600
Extortion and bomb threats	10 000	1 400
Employment practices	35 000	32 000
Uplift liability	65 000	65 000
Key person risk	72 000	37 500
Fraud risk	n/a	52 000
Total	**184 000**	**189 500**

Source: GasNet, *AAI 2002–07*, table 3.9and GasNet, *Submission 2008–12*, table 9.14.

Of the five current categories only the first two (insurer credit risk and the risk of extortion and bomb threats) were approved by the ACCC. The remaining three were included by order of the Australian Competition Tribunal (the Tribunal).

311 GasNet, *Submission*, op. cit., p. 77.

GasNet engaged SAHA International Limited (SAHA) to evaluate the risks for which GasNet should self-insure and the allowances proposed by GasNet accord with those recommended by SAHA. Features of the proposed allowances are the significant reduction in the allowances for extortion and bomb threats and key personnel, and the proposed introduction of a new allowance for fraud risk.

SAHA relied on KPMG's Fraud Survey 2006[312] in estimating the allowance for fraud risk at $52 000 per annum. In calculating the allowance of $52 000 SAHA noted that for organisations roughly the size of GasNet, 34 per cent reported one fraud a year at an average of $152 487. A third of $152 487 is roughly $52 000.

The ACCC agrees that a self-insurance allowance is appropriate. The ACCC appreciates that quantifying the allowances for self-insurance for asymmetric risk is a difficult exercise and there may be a number of ways of quantifying the allowance. The ACCC proposes to accept the approach adopted by SAHA and GasNet.
The ACCC has also examined the allowance GasNet is claiming for uplift risk in view of TRUenergy's comments regarding GasNet's uplift liability cap in the service envelope agreement (SEA). The original SEA commenced on 15 March 1999 and as TRUenergy notes was amended in January 2007 (revised SEA).[313] As TRUenergy notes the liability cap remains at $1 m in the revised SEA at the value struck in 1999. The ACCC was not a party to discussions for either agreement, but considers it most likely that it was intended that GasNet's liability cap under this agreement would be maintained in real terms over time. Clause 18.3 of the revised SEA sets out conditions in relation to amendments:

> Except as set out in the MSO rules or as required by the Regulator, and subject to obtaining any necessary approvals from the Regulator, this agreement may only be amended or supplemented in writing, signed by the parties, generally in the form of Schedule 5.

The relevant regulator, in accordance with interpretation provisions in the revised SEA means the relevant regulator, or regulators, responsible for regulation of the MSO rules and/or AA. In both respects the relevant regulator is currently the ACCC.

The ACCC intends to discuss this issue with GasNet and VENCorp between draft and final decision as to their understanding of whether this $1 m figure was intended to be escalated with inflation, and if so whether they would be prepared to amend the agreement themselves under schedule 5. If this matter is an oversight, then, an amendment, as agreed between the parties via schedule 5, could be achieved by the parties themselves without the need for regulatory intervention.

The ACCC considers that keeping the uplift cap in real terms will become more important over time in placing incentives on GasNet to maintain the system. The ACCC notes that over the long run, if this uplift cap is not escalated by CPI, then the incentive on GasNet to maintain the system may become weaker.

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312 KPMG, *Fraud Survey 2006*, viewed 1 November 2007, <http://www.kpmg.com.au/Portals/0/FraudSurvey%2006%20WP(web).pdf>.

313 The original commencement date of the SEA is noted in GasNet, *Supplementary Access Arrangement Information*, 6 December 2002.

It is noted that a self-insurance allowance of the expected costs associated with its potential liability for uplift payments was included in AA2. These costs were assessed for the AA2 period as amounting to $65 000 in a report prepared for GasNet by TrowBridge Consulting and accepted by the ACCC.[314] The amount of $65 000 represents a small item of expenditure passed on to users annually over the AA2 period. Overall, the ACCC considers that any revenue upside that GasNet may have enjoyed to date as a result of its liability cap not increasing in real terms, but its allowance remaining stable in real terms, will have been marginal.

5.1.5.23 Administrative arrangements

GasNet proposes that any losses incurred by it in respect of the risks for which it self-insures will not be included in calculating reference tariffs, as detailed in cl. 4.11(b) of the proposed AA. This is consistent with cl. 4.12(b) of the second AA.

In 2004, the ACCC has considered the appropriate treatment of self-insurance risk in a number of its decisions and set out the following proposed approach in its Statement of principles for the regulation of electricity transmission revenues:

> The cost of self-insurance will be recognised as an operating expense subject to the implementation of appropriate administrative arrangements including:
>
> 1. a board resolution to self-insure (i.e. a copy of the signed minutes recording resolution made by the board)
> 2. confirmation that the service provider is in a position to undertake credibly self-insurance for those events
> 3. self-insurance details setting out the specific risks which the service provider has resolved to self-insure
> 4. a report from an appropriately qualified actuary or risk specialist verifying the calculation of risks and corresponding insurance premiums
> 5. ensuring that the cost of self-insurance is recorded as an operating expense in the audited and published income statement, and thereby deducted from the calculation of attributable profits
> 6. ensuring that a self-insurance reserve (funded by self-insurance premiums charged in the income statement) is established in the audited and published balance sheet
> 7. ensuring that when a claim against self-insurance is made, that an appropriate deduction to the self-insurance reserve is recorded.

The ACCC considers it inappropriate to allow for self-insurance risk unless the above arrangements are in place. The total amount proposed for self-insurance is considerably higher than that approved by the ACCC for the AA2 period. Given that the total amount was relatively small the ACCC at the time only required modest administrative arrangements. Following GasNet’s appeal to the Tribunal the amount allowed for self-insurance was substantially increased by order of the Tribunal. The Tribunal did not address, however, the issue of whether more stringent

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314 Trowbridge Consulting, *Valuation of non-insured risks*, March 2002 (confidential—GasNet, *Access arrangement submission 2002–07*, 28 March 2002, annexure 7); see also *Application by GasNet Australia (Operations) Pty Ltd* [2003] A CompT 6.

administrative arrangements were warranted in light of the significant increase in the amount allowed for self-insurance.

Without such arrangements supporting the need for self-insurance and the level of costs to be allowed, these costs would not be consistent with s. 8.37 of the code. This is because they would not represent the costs that would be incurred by a prudent service provider acting efficiently in accordance with accepted and good industry practice and to achieve the lowest sustainable costs of delivering the reference service.

These arrangements would be in addition to GasNet's proposed condition as stated in cl. 4.11(b) of its proposed AA.

Proposed amendment 07

Before the proposed revised access arrangement can be approved, GasNet must implement the administrative arrangements 1 to 7 described above in this chapter 5.1 of this draft decision.

5.1.5.24 Equity raising costs

GasNet proposes an annual allowance in AA3 of 0.224 per cent per annum of regulated equity consistent with that approved for in AA2.[315]

In 2002 the ACCC acknowledged the two competing views relating to the validity of an allowance for equity raising costs being that GasNet's initial capital base reflected only the value of physical assets and did not compensate the service provider for capital raising costs, in contrast to the view that the initial capital base incorporated all capital costs.[316] The ACCC considered the former to be the better view and an allowance for equity raising costs was approved. The ACCC noted, however, that this approval of equity raising costs was to be subject to further research in the future.[317]

In 2004 the ACCC engaged the ACG to review the legitimacy of regulated utilities recovering equity raising costs and the benchmark value for such costs.[318] Relevantly, the ACG concluded that the relevant issue to consider is whether the capital base has been established. Specifically if the capital base for a regulated entity:

- has already been established it is not appropriate to include an allowance for the equity raising costs and

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315 GasNet, *Submission*, op. cit., p. 81.

316 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 150.

317 ibid., p. 151.

318 Allen Consulting Group, *Debt and equity raising transaction costs: Final report to the ACCC*, December 2004.

- has not been established and the initial valuation was to be undertaken using a DORC methodology, a benchmark allowance for equity raising costs would appear to be appropriate.[319]

In particular the ACG states:

> …For government owned entities there is similarly no reason to allow initial equity raising transaction costs if there is an established RAV [regulatory asset value], as they can be considered to be implicitly or explicitly incorporated into it. The issue is not whether the utility today is a publicly listed or privately owned, or a government owned business. A company representing the same group of physical assets could have moved through all three of these ownership categories. However, the transaction costs, including IPO [initial public offer] costs (as a proxy) and advisers' fees associated with each of these ownership structures are not relevant to the RAV. They cannot be added to the RAV, or customers would be subsidising what is the pursuit of private (or public) gain through the achievement of synergies or government policy objectives. Thus, the issue is whether an RAV has already been established.[320]

The ACCC has since revised its position and agrees with the ACG's assessment of the issue. The better view the ACCC accepts is that GasNet's initial capital base incorporated all capital costs. In the context of this draft decision, GasNet's initial capital base was established in 1998 and will be rolled-forward for the second time. Accordingly, the ACCC considers there is no case to include an allowance for equity raising costs relating to the capital base to be retrospectively provided.

5.1.5.25 Other allowances

Return on linepack and inventories

GasNet's proposed costs for these items are shown in table 5.1.12. GasNet submits the comparable total figures for GasNet's second AA were \$0.11 m for 2003–04 and \$0.12 m for 2005–07.

Table 5.1.12: Proposal—return on linepack and inventories

2006 Jul \$ m	*2008*	*2009*	*2010*	*2011*	*2012*
Linepack	0.15	0.15	0.15	0.15	0.15
Inventories	0.04	0.04	0.04	0.04	0.04
Total	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**

Source: GasNet, *Submission 2008–12*, table 9.15.

The increased costs are attributed to the additional looping proposed by GasNet. The ACCC proposes costs for the return on linepack of \$140 000 per annum, which are slightly lower than the costs of \$150 000 proposed by GasNet. The ACCC proposes to disallow certain looping projects in GasNet's capital expenditure program. As a result the value of linepack will be less than that proposed by GasNet. The costs of

319 ibid., pp. ix and x.

320 ibid., p. 55.

$140 000 per annum are calculated on a pro rata basis in accordance with total pipeline length.[321]

5.1.6 Conclusion

A summary of the non-capital costs proposed by the ACCC in this draft decision is shown in table 5.1.13.

Table 5.1.13: Draft decision—AA3 non-capital costs

2006 Jul $ m	*2008*	*2009*	*2010*	*2011*	*2012*
Base	**19.55**	**19.55**	**19.55**	**19.55**	**19.55**
Labour	0.62	0.94	1.26	1.60	1.95
Fuel	0.00	0.00	0.00	0.00	0.00
Scope changes	0.74	0.87	0.87	0.87	1.01
Workload changes	1.22	0.81	0.87	0.92	0.97
Sub-total	**22.13**	**22.16**	**22.55**	**22.94**	**23.47**
Less					
Overheads reduction	2.00	2.00	2.00	2.00	2.00
Total opex	**20.13**	**20.16**	**20.55**	**20.94**	**21.47**
Benefit sharing	0.90	–0.69	–1.59	–0.85	0.00
Reset costs	0.95				
K factor carry over[322]	0.91				
Asymmetric risk	0.19	0.19	0.19	0.19	0.19
Equity raising costs	0.00	0.00	0.00	0.00	0.00
Other allowances	0.18	0.18	0.18	0.18	0.18
Sub-total	**3.13**	**–0.32**	**–1.22**	**–0.48**	**0.37**
Total	**23.26**	**19.84**	**19.33**	**20.46**	**21.84**

A summary of GasNet's proposed total non-capital costs (excluding fuel gas) with those proposed by the ACCC is shown in table 5.1.14.[323]

Table 5.1.14: Comparison of total non-capital costs

2006 Jul $ m	*2008*	*2009*	*2010*	*2011*	*2012*
GasNet	24.93	22.65	22.34	24.10	25.52
ACCC	23.26	19.84	19.33	20.46	21.84
% difference	–6.7	–12.4	–13.5	–15.1	–14.4

Source: ACCC analysis.

Proposed amendment 08

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.5.2 of the proposed revised access arrangement information to reflect table 5.1.13 of this draft decision.

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321 ($150 000 x 2010/2096 km) where 2096 km is the total pipeline length under GasNet's proposal and the 2010 kms excludes the looping which the ACCC proposes to disallow.

322 This only includes the KT_b factor for 2006 and will be updated to include the KT_a factor for 2007 prior to the release of the final decision.

323 The percentages in table 5.1.14 differ to figure 5.1.3 which only refers to operating costs, a subset of total non-capital costs.

5.2 Pass-through events

5.2.1 Code requirements

Section 8.3(d) of the code provides that the reference tariff policy may incorporate a 'reference tariff control formula approach'. Under this approach reference tariffs may be varied if a specified event (pass-through event) occurred. Sections 8.3B–8.3H prescribe the approval process if a service provider wishes to vary reference tariffs as a consequence of a specified event occurring.

The mechanics of the pass-through events are considered in chapter 6.3 of this draft decision. This section discusses the merits of each of the pass-through events proposed by GasNet.

5.2.2 Current access arrangement provisions

GasNet's current reference tariff policy contains the following pass-through events, which are defined in the second AA:

- a change in taxes event
- a regulatory event
- an insurance event
- a counterparty default event and
- a terrorism event.

5.2.3 Proposal

GasNet proposes the following changes to its pass-through events:

- A change in the definition of an insurance event. Specifically, GasNet no longer proposes to include as a pass-through event a change in one or more costs in insurance comprising GasNet's minimum insurance level.
- The introduction of an 'asbestos event'.[324] An asbestos event is defined as any cost, expense or liability incurred by GasNet arising out of or in connection with a claim by a third party in respect of an asbestos related disease.[325]

GasNet made no submissions on its proposal to amend its definition of an insurance event.

In support of its proposal to include an asbestos event, GasNet has relied on a report by SAHA International (SAHA). SAHA states that from its experience asbestos is a significant legitimate business risk faced by gas transmission companies around the world. SAHA recommends that GasNet seek a specific cost pass-through provision

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[324] GasNet, *Proposed access arrangement*, op. cit., p. 16.

[325] ibid., p. 13.

given that that the expected cost is subjective and a wide range of values is possible.[326]

5.2.4 Submissions

TRUenergy submits that the number of pass-through events should be limited because of their affect on the incentive mechanism. TRUenergy considers the following criteria should be satisfied for an event to be included as a pass-through event:

- the event should have a material effect on the need for distribution
- the event should be limited and clearly defined
- the event and its financial impact are beyond the control of management and
- the event has a pronounced magnitude in order to prevent excessive regulatory hearings.[327]

TRUenergy submits that the following events should not be allowed as pass-through events:

- a counter party default event and
- an asbestos event.

In respect of the counter party default event, TRUenergy considers that gas users should not underwrite GasNet's commercial credit risks. TRUenergy submits that firms in a competitive market are generally unable to pass-through bad debts and GasNet should not be given special treatment.[328]

Regarding the asbestos event, TRUenergy drew a parallel with the James Hardie case. TRUenergy notes that in that instance James Hardie were unable to pass on the costs of the asbestos claims onto its customers and accordingly GasNet should not be allowed to do so in similar circumstances.

TRUenergy has no objection to the other events proposed by GasNet as pass-through events. In general, TRUenergy considers that pass-through events should be limited to events outside the control of the service provider. Including other events would have the effect of transfer risk from the service provider to gas users, remove incentives for service providers to mitigate against such risks and lead to frequent contentious pass-throughs.[329]

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326 SAHA International, *Self Insurance Risk Assessment*, 26 April 2007, p. 18. (GasNet, *Submission*, op. cit., attachment E).

327 TRUenergy, op. cit., p. 11.

328 ibid.

329 ibid.

5.2.5 Assessment

5.2.5.1 Change in insurance event

GasNet did not provide reasons for the proposed change to the definition of an insurance event. The effect would be that a change in one or more costs in insurance comprising GasNet's minimum insurance level will no longer be passed through. Instead, GasNet will bear the risk of any change to its minimum insurance level.

The ACCC supports this approach. Insurance costs are not likely to be as volatile as they were at the commencement of the AA2 period. However, the ACCC was concerned that the definition as now proposed by GasNet created the potential for GasNet to over recover costs. Potentially GasNet could elect not to insure for certain risks currently within its minimum insurance level, yet at the same time receive revenue from reference tariffs to cover the costs. The ACCC did not consider that this was GasNet's intention and raised the apparent anomaly with GasNet.

Consequently GasNet proposes to amend the definition of Insurance Event to only cover circumstances in which GasNet is required to pay a deductible in connection with a claim under an insurance policy. GasNet also proposes to remove the definition of minimum insurance level as it is not referred to elsewhere in the proposed AA. The ACCC supports GasNet's proposal.

Before the proposed revised AA can be approved, GasNet must amend the definition of a Pass Through Event in cl. 9.1 of its proposed revised AA to remove the reference to an Asbestos Event.

Proposed amendment 09

Before the proposed revised access arrangement can be approved, GasNet must:

- amend the definition of an Insurance Event in cl. 9.1 of its proposed revised access arrangement to only cover circumstances where GasNet is required to pay a deductible in connection with a claim under an insurance policy and
- remove the definition of Minimum Insurance Level from in cl. 9.1 of its proposed revised access arrangement

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5.2.5.2 Counter party credit risk

TRUenergy opposes the inclusion of counter party credit risk as a pass-through event. GasNet proposed counter party credit risk as a self-insurance allowance for AA2. The ACCC agreed with this approach in principle but approved a significantly lower amount ($10 000) to that proposed by GasNet ($250 000). The Tribunal ordered, however, that counter party credit risk would be treated as a pass-through event.

5.2.5.3 Asbestos risk

GasNet's proposal to include asbestos risk as a pass-through event, rather than as an allowance for self-insurance is supported by SAHA. SAHA suggests including the asbestos risk as a pass-through event because of the difficulties in arriving at an appropriate amount for a self-insurance allowance. In justifying its proposal, SAHA refers to the James Hardie experience as evidence of the potential liability associated with asbestos-related compensation claims.[330]

The ACCC agrees, however, with TRUenergy's views. The costs of any future compensation claims should be borne by GasNet and not passed on to gas users. To allow the costs associated with asbestos risk as a pass-through event would act as a disincentive to GasNet to manage the risk.

In the James Hardie matter it was the company's shareholders that bore the costs of the compensation claims, not James Hardie's customers. In a competitive market a company may be unable to pass the costs of asbestos-related compensation claims onto its customers.

If GasNet is unable to insure against this risk, the ACCC will consider any substantiated proposal by GasNet for self-insurance.

Proposed amendment 10

Before the proposed revised access arrangement can be approved, GasNet must amend the definition of a Pass Through Event in cl. 9.1 of its proposed revised access arrangement to remove the reference to an Asbestos Event.

5.2.5.4 Fuel gas

As considered in section 5.1.5 of this draft decision, the ACCC proposes that changes to GasNet's fuel gas costs from the base year (2006) should be treated as a pass-through event. The ACCC also proposes that GasNet must tender for its fuel gas requirements.

Proposed amendment 11

Before the proposed revised access arrangement can be approved, GasNet must include:

- changes to its fuel gas costs from the base year (2006) as a pass-through event, excluding any fuel gas costs associated with the Euroa compressor and
- as a condition that GasNet must tender for its fuel gas requirements.

5.2.5.5 Immaterial pass-through amounts

GasNet proposes that if the aggregate of all pass-through amounts for any year is less than $50 000 then GasNet is not required to prepare a statement under cl. 6.1 the proposed AA. GasNet would have the discretion not to seek to pass-through immaterial amounts. The ACCC supports this proposal.

330 SAHA International, op. cit., p. 18. (GasNet, *Submission*, op. cit., attachment E).

5.3 Inflation

5.3.1 Code requirements

Section 8.5A of the code provides that the amount of total revenue can be determined under a nominal or real approach or 'on any other basis in dealing with the effects of inflation' provided that it is specified in the AA, approved by the regulator, and applied consistently.

The relevant regulator must also be satisfied that any forecasts used in setting the reference tariff represent best estimates arrived at on a reasonable basis.[331]

5.3.2 Proposal

For the purposes of its proposed AAI and AA submission, GasNet has calculated its revenue requirement in nominal terms, using a forecast inflation rate of 3.09 per cent. Reference tariffs have been calculated such that they will incorporate an actual inflation adjustment throughout the period.

5.3.3 Submissions

No submissions were received on this aspect of the proposed AA.

5.3.4 Assessment

The ACCC has examined GasNet's revenue calculations and notes that a nominal framework has been applied in a consistent manner across the various elements such as the rate of return, the calculation of costs and depreciation. The use of a nominal framework rather than a real one does not impact on the total revenue for the AA period.

While the choice of nominal or real terms can be selected by the service provider, the code does require the regulator to be satisfied that estimates, of which forecast inflation is one, are the best estimates arrived at on a reasonable basis.

GasNet has derived its inflation estimate as the difference between the yields on nominal and indexed Commonwealth Government securities. As noted in chapter 4 of this draft decision, the ACCC has concerns in relation to the use of indexed yields and instead considers that reference to replicable, transparent, objective and widely available market data is likely to result in the best estimate of the forecast inflation rate. For the purposes of this draft decision the ACCC considers this results in a best estimate of the forecast inflation rate of 3.0 per cent.

[331] In accordance with s. 8.2(e) of the code.

5.4 Volumes

5.4.1 Code requirements

Section 8.2(e) of the code requires that any forecasts required in setting the reference tariff should represent best estimates arrived at on a reasonable basis.

5.4.2 Current access arrangement provisions

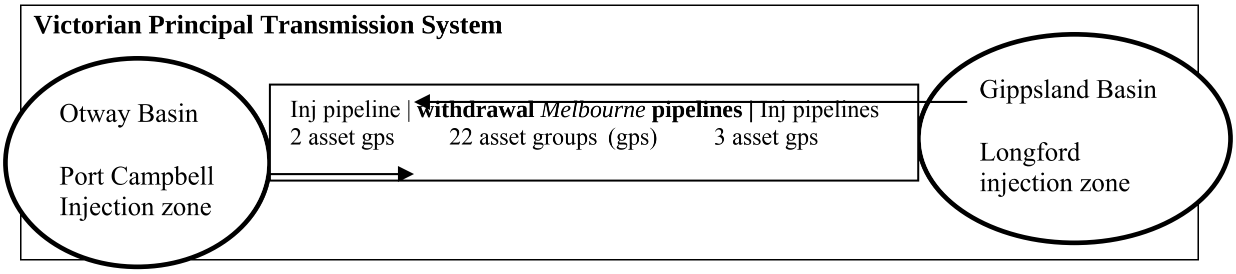
GasNet's usage of volumes for cost allocation and as a charging basis for AA2 is set out in table 5.4.1.

5.4.3 Proposal

5.4.3.1 Volume usage in GasNet tariffs—cost allocation and charging

Under GasNet's tariff model, as considered in chapter 6.1 of this draft decision, the physical flow path method of cost allocation means most users are allocated costs on the basis of causing gas volumes to flow from the Gippsland Basin (Longford injection zone) through injection pipelines to an off-take point within the connected withdrawal pipeline system. Flows from Longford are stronger and flow further through withdrawal pipelines (separated into 22 withdrawal asset groups) than flows from the next most significant source, the Otway Basin (Port Campbell injection zone). This means that users to the north/west of Melbourne in general pay withdrawal tariffs based on the usage of more withdrawal assets than gas users to the east of Melbourne who are closer to Longford. This is depicted in figure 5.4.1.

Figure 5.4.1: Matching asset usage to injection source



*arrow represents depth of flow of gas into the system

GasNet's cost allocation methodology is considered in terms of the combined effect of volumes, distance and asset group costs on costs allocation to users for withdrawal tariffs/injection tariffs to recover withdrawal asset/injection asset costs.

GasNet proposes to charge users over one set of volumes—anytime withdrawals for withdrawal tariffs and four month winter peak withdrawals for injection tariffs.[332]

[332] GasNet uses the term anytime withdrawals to refer to all withdrawals at anytime through the year. This is equivalent to annual volumes.

The difference between that approved in the AA2 period and that which GasNet proposes for the AA3 period in relation to volume usage in cost allocation and volume usage as a charging basis is set out in table 5.4.1.

Table 5.4.1: Volume basis for cost allocation and charging[333]

Type of tariff		*Injection tariffs for injection asset usage*	*Withdrawal tariffs for withdrawal asset usage*
AA2	*Volume basis for cost allocation*	Costs are allocated to users of assets based on the specific cost to be recovered for that asset i.e. Longford or Southwest pipeline.	45 per cent of withdrawal asset costs are allocated using forecast peak withdrawal volumes (matched to an injection source (mtais)) with the remaining 55 per cent allocated using forecast anytime withdrawal volumes (mtais).
	Volume basis for charging	Top ten peak day injection volumes.	Anytime withdrawal volumes
AA3	*Volume basis for cost allocation*	65 per cent of costs are allocated using peak injection volume forecasts and 35 per cent on the basis of anytime injection volume forecasts.	65 per cent of withdrawal asset cost are allocated using forecast peak withdrawal volumes (mtais) with the remaining 35 per cent allocated using forecast anytime withdrawal volumes (mtais).
	Volume basis for charging	Four month winter volumes	Anytime (annual) withdrawal volumes

In chapter 6.1 of this draft decision, the ACCC has proposed GasNet retain the approach approved for the AA2 period in calculating injection tariffs as set out in the table 5.4.1. Given this proposed amendment, the ACCC must consider the following volumes against s. 8.2(e) of the code in setting the reference tariff:

- peak day, top ten peak day and annual injection volumes forecast and
- peak day and annual withdrawal volumes forecast.

Both injection and withdrawal volumes are considered below. In accordance with the physical flow path method of cost allocation, GasNet has set injection and withdrawal volumes on the basis of peak and anytime (annual) withdrawal forecasts (given withdrawals must be matched to an injection) in its tariff model.

GasNet’s proposed withdrawal volume forecasts are predominately based on VENCorp’s forecasts. In contrast, GasNet has independently provided injection volume forecasts across injection zones for AA3.[334]

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333 Tariff models provided by GasNet to the ACCC; GasNet, *Submission*, op. cit., schedule 5.7.

334 GasNet, *Submission*, op. cit., p. 89.

5.4.3.2 Withdrawal volumes

As noted in table 5.4.1, GasNet's proposed withdrawal tariffing approach relies on peak and anytime (annual) withdrawal volumes forecasts (as well as annual and peak injection forecasts).

GasNet's total revenue outcome is sensitive only to anytime withdrawal volumes because of its proposed average revenue yield approach which is set on the basis of forecast total annual volumes withdrawals. This average revenue yield is considered in chapter 6.3 of this draft decision as is GasNet's proposal to have a bounded revenue risk to anytime withdrawal volumes differing to forecast. Accordingly, withdrawal volume forecasts are of primary importance in terms of a potential for over/under recovery of revenue over the period.

Peak volume forecasts, because of GasNet's average revenue yield approach will not affect revenue outcomes, but are relevant to the allocation of costs across tariff zones and tariff-V (small) and tariff-D (large) users within tariff zones. Tariff zones/user types attributed to having more peak use (than other tariff zones/user types) will be attributed more costs.

GasNet notes that it has used the VENCorp 2006 Gas Annual Planning Report (GAPR) medium economic growth scenario forecasts of annual and peak withdrawals but made some relatively minor adjustments to these volumes, which it considers necessary for tariffing purposes.[335] These volumes are shown in table 5.4.2.

Table 5.4.2: Annual and peak volume forecasts[336]

	2008	*2009*	*2010*	*2011*	*2012*
Annual volumes					
VENCorp annual volumes	219.2	219.6	220.7	221.8	224.1
GasNet adjusted volumes for tariffing purposes*	222.5	224.1	226.5	227.6	229.9
Peak volumes					
VENCorp 1 in 2 peak day forecast (no GPG forecast)	1168	1174	1183	1192	1205
GasNet adjusted volumes for tariffing purposes*	1233	1239	1248	1256	1270

* Adjustments made to annual and peak volume forecasts include export tariffs, storage refill and exclude compressor fuel usage. Additionally, GasNet assumes 50 TJ of peak volumes for GPG usage.

(i) *Assumptions—VENCorp forecasts*

Two key assumptions which underpin the VENCorp forecasts and which GasNet adopts are:

- the medium economic growth scenario of volume forecasts set out in appendix A to VENCorp's 2006 GAPR and

[335] ibid.

[336] ibid., p. 87.

- the effective degree day (EDD) assumptions underpinning these medium growth forecasts.

The concept of EDDs and their effect on volumes under GasNet's proposal for the AA3 period requires some brief explanation.

The significant use of gas for space heating on the PTS means that volume forecasts are particularly sensitive to assumptions relating to the coldness of weather (as expressed by EDD values) and the effect on gas usage as weather gets colder (the TJ/EDD sensitivity). As an approximation, an extra EDD would occur on the PTS if, instead of a 17 degree average temperature day, a 16 degree day occurred. In accordance with analysed temperature sensitivities this would affect daily gas usage (and annual gas usage) where gas usage would be approximately 45 TJ higher.[337]

For the AA2 period, GasNet proposed alternative EDD values for volume forecasting purposes to those assumed in VENCorp's forecasts on the basis of concerns as to the impact on its revenue associated with a weather warming trend.[338] GasNet has borne total risk from EDD outcomes being different to forecast over AA2, particularly in 2005, as illustrated in table 5.4.5.

For the AA3 period, GasNet proposes to include VENCorp withdrawal forecasts based on VENCorp's review of the EDD conducted in 2006. This review concluded lower annual and system peak day EDD values compared to 2003.[339] The difference in EDD assumptions between reviews is outlined in table 5.4.3.

Table 5.4.3: EDD values

EDD	*2003 VENCorp review*	*2006 VENCorp review*
Annual EDD standard	1396	1340
1 in 2 (1 in 20) peak day	14.60 (16.75)	14.35 (16.50)

337 The yearly forecast of the number of EDDs represents a forecast of the likely coldness of weather over each day of the year. A figure will be recorded when in general the temperature recorded falls below a threshold level of 'coldness' of approximately 18 degrees, occuring most often in winter. An EDD number is calculated on the basis of an equation which takes account of the degree of variation below of the average temperature to the threshold level of 18 degrees and accounts also for sunshine, wind and a seasonal impact. VENCorp notes that the temperature of 18 degrees within the formula represents a threshold for residential gas heating which is a common standard internationally: see VENCorp, *Review of the Effective Degree Day Weather Standards: Final Report (EDD review)*, September 2006.

338 For the AA2 period, the ACCC approved a downwards adjustment to volumes compared to the VENCorp volume forecasts accepting that there would be stronger weather warming effects over the AA2 period than forecast by VENCorp. In 2004, the ACCC approved a further downwards adjustment to volumes to reflect the impact of further analysis of warming trends: see ACCC, *Final Decision: Access Arrangements for the Principal Transmission System*, 15 December 2004, ch. 5.

339 The VENCorp volume forecasts also incorporate the calculated relationship between expected gas usage for each occurrence of an EDD. Between 2008 and 2011 the sensitivity used in volume forecasts is 44.8, 45.2, 45.5, 45.9 TJ/EDD: VENCorp, *Email to the AER*, 4 May 2007.

For the AA3 period, GasNet proposes to adopt VENCorp's EDD assumptions without revision but to remove the impact to its revenue stream of actual EDD outcomes differing from forecast outcomes through a formula within its price control formula. This formula adjusts recoverable revenue (with losses/gains against actual revenue to be recovered in subsequent years of the AA period) by the difference between forecast (target) and actual EDDs. In simple terms:

$$\text{recoverable revenue} = (\text{actual VW} + \text{TS} \times (\text{target EDD} - \text{actual EDD})) * \text{AY}$$ [340]

where:

VW	volumes withdrawn	EDD	effective degree days
TS	temperature sensitivity	AY	allowed revenue yield

The ACCC understands that GasNet has not proposed any changes to the VENCorp EDD forecasts on the basis of GasNet's proposal (being accepted) to include GasNet's adjustment formula for EDD outcomes different to forecast.[341]

5.4.3.3 Annual GPG forecasts in VENCorp forecasts

GasNet proposes to adopt the VENCorp 2006 GAPR forecasts of annual GPG usage of between 6–7 PJ over the AA3 period.[342] These forecasts represent a significant decrease to annual GPG forecasts compared to the second AA period where 12–17 PJ annually were included in forecasts as detailed in tables 5.4.5 and 5.4.6.[343] The assumptions underpinning the AA3 GPG forecasts are slower growth in electricity demand, and increased electricity supply from Basslink and wind farms.[344]

5.4.3.4 GasNet adjustments and additions to VENCorp withdrawal forecasts

GasNet proposes for tariffing purposes to adjust VENCorp's annual and peak withdrawal forecasts for the following:

- compressor fuel usage
- interstate gas exports
- storage refill volumes and
- peak day gas powered generation (GPG) volumes.[345]

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340 GasNet, *Proposed access arrangement*, op. cit., sch. 4.

341 ACCC meeting with GasNet, 22 August 2007.

342 VENCorp, *2006 Gas Annual Planning Report*, p. 10.

343 id., *2001 Gas Annual Planning Report*, November 2001; Volume models provided by GasNet to the ACCC a part of the AA2 review.

344 id., *2006 GAPR*, op. cit., p. 11.

345 GasNet, *Submission*, op. cit., p. 87.

(i) *Adjustments—compressor fuel*

VENCorp's withdrawal volume forecasts include an amount for compressor fuel. The ACCC understands that GasNet has deducted this amount from the VENCorp annual forecasts as this cost is not subject to a transmission charge directly. GasNet recovers compressor fuel costs as operating expenditure.[346]

(ii) *Inclusions—exports, refill and GPG peak volumes*

VENCorp forecasts do not include interstate gas exports, the temporary withdrawal of gas from the PTS into storage refill or peak GPG forecasts for which GasNet levies tariff on users. GasNet's proposed volumes over the AA3 period for these tariffs are set out in table 5.4.4.

Table 5.4.4: Exports refill and GPG peak volumes[347]

2008–2012	*Annual (PJ)*	*Peak (TJ)*
Exports Culcairn	2.5 (2008), 5.0 (2012)	17 TJ/day
Exports VicHub	0.3	1.0
WUGS refill	0.5	0
Dandenong refill	0.3	0
GPG	n/a	50

GasNet forecasts annual exports of 2.5 PJ at Culcairn from 2008, increasing to 5 PJ by 2012 on the basis of expected increases in demand from an energy retailer in NSW and from a gas fired generator to be located near Wagga Wagga. GasNet notes that flows into refill storage have been as high as 18.3 PJ per annum in 2004, but it now forecasts 0.5 PJ per annum to be injected into refill annually at the underground storage facility (UGS). GasNet submits that it expects limited use of refill over AA3, because suppliers can now directly inject gas into UGS from the adjacent offshore field. GasNet states that it has arrived at its peak GPG forecast on the basis of historical analysis and past VENCorp statements.[348]

5.4.3.5 Injection volumes

GasNet submits that there is no independent source of information that provides injection volume forecasts. GasNet submits its own forecasts, which it states it has derived from a combination of:

- historical data
- known developments in the producing fields and
- from the necessity to balance supply and demand each year.[349]

[346] ibid.

[347] ibid.

[348] ibid. pp. 88 and 89.

[349] ibid., p. 90.

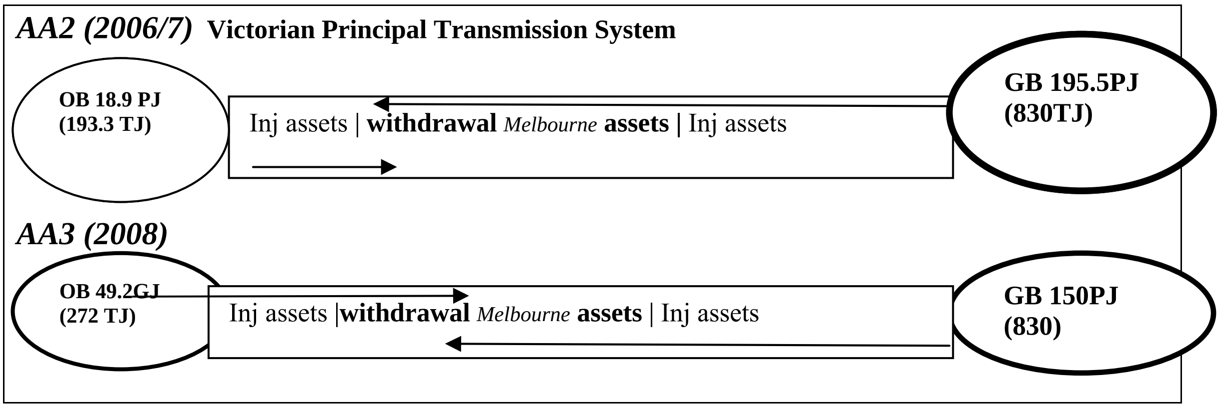
GasNet submits these known developments include:

- The Yolla Gas field recently commissioned and producing at its planned capacity of 67 TJ/day.
- The Otway Basin, the Minerva and Casino Fields, currently in production, and to be supplemented by the Thylacine/Geographe fields during 2007. GasNet notes that total annual production is likely to exceed 120 PJ per annum, which it is assumed will be allocated between Victorian and South Australian volumes and that volumes of between 50–60 PJ per annum will be injected into Victoria.

In regards to necessity to balance supply and demand each year GasNet states that gas supply is a competitive process, whereby retailers and gas producers compete with each other to supply the demand for gas. GasNet submits that while injections from the Longford injection zone (the Gippsland Basin) will remain the largest supply over AA3, volumes are expected to fall as competition intensifies from Yolla (Pakenham injection zone) and the Port Campbell injection zone (Otway Basin). GasNet states that whilst it has assumed an increased volume flow from the Otway Basin based on increased pipeline capacity and production (and consequently less from Longford), that these injections can only be conjectured.[350]

GasNet's assumptions are depicted in figure 5.4.2.

Figure 5.4.2: Comparison of forecast injection source between AA2 and AA3[351]



* Simplified depiction of annual/peak gas flow on PTS from the Otway Basin (OB) and Gippsland basin (GB) denoting the general change in flow of gas from AA2 to AA3. Additionally injections at Yolla (20 PJ annual/ 67TJ peak day) are forecast as constant over the period. Flows from the Otway Basin are forecast to rise over the AA3 period to 59 PJ (annual) and 328 TJ (peak day).

This forecast change of more Port Campbell injection zone volumes results in some users paying for usage of withdrawal assets connected to the Otway Basin side for the first time (such as users west of Melbourne) since as a result of these stronger forecast flows (depicted by the length of the arrows above) gas will flow further from the Otway Basin along connected withdrawal assets.

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350 ibid., pp. 90–92.

351 ibid., pp. 89 and 90 (2008 data); GasNet, *Email to the AER*, 31 July 2007 (2006–07 data).

(i) *Longford/VICHub injection point*

GasNet proposes constant injection volumes over the AA3 period:

- annual injections of 150 PJ (for 2006–07 injections were 195.5 PJ)
- peak day injections of 830 TJ (for 2006–07 injections were 932.9 TJ) and
- four month winter injection volumes of 66 PJ.[352]

GasNet states that whilst there is ample spare capacity at Longford it anticipates that both peak and annual volumes will fall in competition with Pakenham and Port Campbell injections. GasNet notes in relation to annual injection volumes that it is assuming that that Pakenham and Otway supply will reach 70 PJ per annum by 2008. GasNet further notes that the 830 TJ forecast for peak injections is an assumed fall from historic injection volumes. GasNet assumes that forecast growth in peak (35 TJ) and annual demand (7.3 PJ) over the AA3 period will be met by balancing injections from Port Campbell. Therefore, GasNet proposes to assume that the other injection point volumes, such as Longford, will be constant over the period.[353]

(ii) *Pakenham*

GasNet proposes constant volumes over the AA3 period:

- annual injections of 20 PJ, (for 2006–07 injections were 16 PJ)
- peak day injections of 67 TJ (for 2006–07 65.4 TJ) and
- four month winter injection volumes of 7 PJ.

GasNet states that the Yolla gas field in Bass Strait is projected to supply base load gas volumes of 20 PJ per annum and a peak of 67 TJ/day. GasNet submits that the profile should be reasonably flat across each year of the AA3 period.[354]

(iii) *Port Campbell (Otway Gas and Underground Storage)*

GasNet submits volumes will increase, specifically:

- annual injections rising steeply from 18.9 PJ in 2006–07 to 49.2 PJ in 2008 and 59 PJ by 2012
- peak day injections rising from 193.3 TJ in 2006–07 to 272 TJ in 2008 and 328 TJ by 2012 and
- four month winter injection volumes of 25.7 PJ in 2008 rising to 30.9 PJ in 2012.[355]

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352 GasNet, *Submission*, op. cit., p. 91

353 ibid.

354 ibid., pp. 90 and 91.

355 ibid., p. 91.

GasNet notes that traditionally 10 PJ of gas has come from underground storage to meet the winter peak, but in 2006 base load injections from Port Campbell provided a total of 22 PJ per annum into the PTS. GasNet states that it expects that base load injections for the period will increase as the Thylacine/Geographe fields are brought into production in 2007. GasNet projects a fixed base load injection from 2008 of 45 PJ per annum and forecasts that there will be balancing injections, starting at 4.2 PJ in 2008 (principally from underground storage) which will grow as the underlying gas demand grows. GasNet submits that it has treated Port Campbell peak injections as the balancing injection source on the PTS after deducting the forecast peak day injections from other injection sources. It states that it has tested this forecast against the notified production capacity (VENCorp GAPR 2006) and the known capacity of the Southwest pipeline to ensure that the volumes can be carried.[356]

(iv) *Culcairn and Dandenong*

These are comparatively small injection sources in comparison to the other three injection sources. At Culcairn, GasNet forecasts that as export volumes increase, and as gas trading activity is likely to increase at the Culcairn hub, annual injection volumes will fall from 3 PJ in 2008 to 0.5 PJ per annum by 2012. GasNet forecasts peak day injections to be 34 TJ in 2008 falling to 15 TJ in 2012.[357] GasNet projects an annual LNG volume at Dandenong of 3 PJ per annum over AA3, which is assumed to be marginally higher than historical averages on the assumption that LNG is likely to be utilised to a greater extent in the new wholesale gas market. GasNet assumes peak injections to be 30 TJ/day.[358]

5.4.4 Submissions

(i) *Gas powered generation forecasts*

TRUenergy comments that VENCorp has stated that GPG usage in 2007 has been much greater than the usage assumed for AA3. TRUenergy notes that at the time of writing it was not clear if this increased gas usage by the electricity generation sector may be drought related so it is not clear if it will be sustained over the five years.[359]

TRUenergy refers in its submission to a commissioned report on the future of GPG usage in Victoria/Tasmania. Under the base case scenario in this report, it is assumed that gas generation demand will rise across Victoria and Tasmania from 20 PJ per annum in 2006 to approximately 50 PJ in 2012. However, TRUenergy has not made this report available to the ACCC and it is unclear:

- what portion of this forecast volume represents usage in Victoria and Tasmania and

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[356] ibid.

[357] ibid., p. 92.

[358] ibid.

[359] TRUenergy, op. cit., p. 9.

- whether it is a combination of co-generation forecasts, as well as GPG in the electricity sector.

TRUenergy submits there is a strong possibility of GPG usage being higher than forecast over AA3 and on this basis supports removing the variations between actual and forecast volumes for GPG from the price control formula on an annual basis.[360]

Origin Energy expresses a concern that consumers may be deprived of the opportunity to benefit from any increased demand for GPG. It notes in this context that VENCorp's medium forecast for GPG is relatively conservative and has already been overtaken by significant amounts in the last three out of four years (including 2007) notwithstanding that Laverton North power station has not been in full commission during this period. Origin Energy urges the ACCC to either maintain the current revenue control model, or at a minimum seek a further review of the 2006 VENCorp forecast, and the sensitivity of GasNet's total revenue to variations from this forecast.[361]

5.4.5 Assessment

GasNet's volume forecasts represent a critical element of this regulatory assessment. GasNet proposes to bear some total volume risk/reward in its revenue stream for total annual withdrawal volume outcomes. For tariff setting purposes, (i.e. cost allocation and charging to users at tariff zones) both annual and peak forecast volumes are of importance.

5.4.5.1 Annual withdrawal volume forecasts

GasNet under its proposed modified average revenue yield control is subject to aggregate demand risk and will earn greater (less) revenue than forecast revenue if actual demand is greater (less) than that forecast. GasNet's proposal therefore incorporates an incentive to exceed its demand forecasts. It may achieve this by encouraging demand growth but it may also achieve this by basing tariffs on conservative demand forecasts. However, GasNet's opportunity to bias downwards AA3 volumes is limited given that it proposes to adopt VENCorp's volume forecasts for AA3. GasNet's forecast and actual volumes for AA2 are outlined in table 5.4.5.

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360 ibid.

361 Origin Energy, op. cit., p. 3.

Table 5.4.5: AA2 volumes (actual and forecast)[362]

Annual Volumes (PJ)	*2003*	*2004*	*2005*	*2006*	*2007*	*5 year*
Forecast	216.2	223.8	**231.2**	235.7	239.8	1146.7
Actual	213.4	225.3	**204.4**	224.6	Based on April 2007 GasNet forecasts a 4.6% total shortfall over 5 years (does not include new high 2007 GPG estimate below).	
Inc. GPG forecast	12.2	14.3	15	15.9	*17.6*	*75*
Inc. GPG actual	4.7	16.6	5.5	8.4	Based on the ACCC's August 2007 estimate of 32 PJ for GPG volumes the 5 year volume shortfall will be 8 PJ.	
EDD forecast	1434	1429	**1386**	1379	1372	N/A
EDD actual	1453	1411	**1187**	1392	n/a	n/a

In 2004 GasNet sought a voluntary revision to adjust volumes to reflect a higher weather warming trend. This explains the step jump down in forecast EDD from 2004 to 2005.

Actual volumes during the AA2 period have fluctuated around forecast volumes with GPG volumes and EDD outcomes against forecast being strong contributors. In particular in 2005 as highlighted above, warm weather (a low EDD value) and low actual GPG volumes compared to forecast contributed to total volumes well below forecast. GasNet forecasts an increase in annual withdrawals over the AA3 period though the forecasts are less in total than the forecast annual withdrawals for AA2. GasNet forecasts for AA3 are outlined in table 5.4.6.

Table 5.4.6: AA3 forecasts[363]

Annual Volume	*2008*	*2009*	*2010*	*2011*	*2012*	*5 year*
(PJ)[a]	221.7	223.3	225.7	226.8	229.1	1126.6
Inc. GPG forecast	*6.8*	*6.7*	*6.7*	*6.7*	*6.7*	*33.6*
EDD forecast[b]	1340	1340	1340	1340	1340	n/a

(a) Annual forecast excludes 0.8 PJ of refill volume to enable comparison with AA2 data, which does not include refill volumes.

(b) VENCorp has chosen to adopt a mid point constant value of 1340 for all volume forecasts for the 2006 GAPR planning period rather than the trend downwards which its 2006 review analysed.

A comparison of EDD assumptions, and forecast volumes in tables 5.4.5 and 5.4.6 above illustrates the two main reasons why volume forecasts for AA3 are lower in total than for AA2:

- AA3 forecasts incorporate a lower EDD than for AA2 derived from a more recent projection of the EDD and

362 Data sources: (1) GasNet, *GasNet Australia Access Arrangement—Application to revise*, 24 August 2004; (2) GasNet, *Access Arrangement Information*, 15 December 2004, table 4-2; (3) data provided by GasNet to the ACCC in the AA2 and AA3 reviews; (4) VENCorp, *2001 GAPR*, op. cit.; (5) VENCorp, *2006 GAPR*, op. cit.; (6) VENCorp, *EDD Review*, op. cit.; and (7) ACIL Tasman, *Final Report: GasNet GPG forecasts—Review of GasNet gas power generation forecasts within the 2008–12 access arrangement period*, 13 August 2007.

363 Data sources: (1) GasNet, *Submission*, op. cit.; (2) GasNet, *Proposed AAI*, op. cit.; (3) GasNet, *Email to the AER*, 25 June 2007.

- AA2 forecasts included higher GPG forecasts.

Volume forecasts across the AA3 period are nevertheless inclining consistent with GasNet adopting the VENCorp medium economic growth scenario of positive overall volume growth from the 2006 GAPR.[364]

GasNet annual volume forecasts encompass VENCorp 2006 GAPR medium economic growth scenario volume forecasts. The ACCC notes VENCorp has:

- derived these forecasts independently of GasNet
- consulted with major gas users prior to setting its demand forecasts as noted in Appendix A to its 2006 GAPR
- extensive experience with producing and revising volume forecasts annually since its inception in 1997 and its first annual planning report published in 1999
- engaged a consultant with experience in the field of volume forecasting to assist it in its task[365] and
- included within volume forecasts recent conclusions of the September 2006 review of the EDD value as a measure of likely weather coldness in future years.

5.4.5.2 Assumptions—medium economic growth scenario and EDD

As it did for AA2, the ACCC considers that adoption of VENCorp's medium economic growth scenario of withdrawal volume forecasts is consistent with choosing a best estimate of volumes in accordance with s. 8.2(e) of the code.

In respect of the EDD values chosen, VENCorp consulted with industry on a recalculation of the EDD in 2006 and issued a final report that includes revised lower values for EDD for the 2007–11 planning period.[366] VENCorp concluded both a lower and declining EDD value. The degree of decline is generally consistent with a recent 2007 CSIRO report submitted by the distribution businesses to the ESC, although the baseline value for 2006 differs by 41 EDDs.[367]

EDD assumptions have historically underpinned volume forecasts and as a consequence revenue volatility in Victoria for regulated gas distribution and transmission companies. For the AA2 period, the ACCC considers that GasNet will, in part, under-recover against its allowed volumes/revenue because actual EDD outcomes were below EDD forecasts particularly for 2005 as shown in table 5.4.5. That is, weather was warmer than forecast, (and volumes/revenue less than forecast).

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364 VENCorp, *2006 GAPR*, op. cit., pp. 9 and 10.

365 VENCorp engaged the National Institute of Economic and Industry Research (NIEIR).

366 VENCorp, *EDD Review*, op. cit., p. 26.

367 CSIRO, *Projected changes in temperature and heating degree-days for Melbourne and Victoria, 2008-2012*, March 2007.

GasNet aims to remove revenue volatility to the amount of EDDs on the system over AA3 through the formula set out in section 5.4.3.2 of this draft decision.

This formula, in the context of GasNet's price control formula, means that if actual EDDs are above the standard EDD because of a colder year than original forecasts then revenue equal to (ΔEDD×45TJ×average revenue yield) has to be returned to users by tariff reductions in following years. As a result, the formula removes the effect of additional/less revenue caused by EDD deviations from forecast. Through this formula GasNet and users will not share in revenue at risk consequent on EDD outcomes, where large deviations in any one year can occur such as in 2005 as noted in table 5.4.5. The ACCC notes that GasNet's proposed approach necessarily relies on an assumption of accurate VENCorp forecasts of the TJ/EDD sensitivity of gas usage. In respect of the TJ/EDD forecast, the ACCC is not aware that temperature sensitivities used in volume forecasting have been widely disputed as is the case of the yearly EDD number. VENCorp forecasts an inclining sensitivity of gas usage to a change in the EDD, expressed as TJ/EDD, over the period.[368] This implies an inclining temperature sensitivity consistent with general growth in demand on the system.

In the context of:

- GasNet proposed adjustment approach to make revenue neutral to EDD outcomes and
- the revenue control model which GasNet has provided to the ACCC

the ACCC considers that the VENCorp EDD and TJ/EDD used represent best estimate forecasts arrived at on a reasonable basis in accordance with s. 8.2(e) of the code.

5.4.5.3 Gas power generation (GPG) forecasts

As noted in table 5.4.5 and 5.4.6, GasNet's forecast GPG volumes for AA3 are about 8 PJ less annually on average than for AA2. GasNet makes no comment in its submission on annual GPG usage forecasts. However, GasNet has commented to the ACCC that in general it expects that following high GPG usage experienced in 2007 a normal pattern of lower GPG usage would resume once water supplies had returned to normal levels.[369]

TRUenergy and Origin Energy both queried GasNet's GPG forecasts.

The ACCC notes that actual GPG usage was approximately 20 PJ at the end of July.[370] In contrast, the forecasts of GPG proposed by GasNet for AA3 ranges between 6–7 PJ.[371] The variance between 2007 actuals and AA3 forecasts raises

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368 VENCorp, *Email to the AER*, 4 May 2007.

369 GasNet, *Email to the AER*, 26 June 2007.

370 VENCorp, *Email to the AER*, 27 June 2007. This included volume data up to 25 July 2007 (18 PJ).

371 id., *2006 GAPR*, op. cit., p. 10.

concern that the difference will be repeated for part or all of AA3. If this occurs, GasNet could receive a significant revenue upside constrained by its 5.5 per cent bounded average revenue yield control.[372]

In response to submissions and the ACCC's concerns regarding GasNet's proposed GPG forecasts for the AA3 period, the ACCC engaged ACIL Tasman Pty Ltd to review GasNet's GPG forecasts.[373] Following its review, ACIL Tasman concludes there will be heightened price levels in the National Electricity Market (NEM), which is expected to result in heightened levels of gas fired dispatch from the Victorian gas peaking stations until early 2009.

ACIL Tasman's projected annual GPG consumption is set out in table 5.4.7.[374] ACIL Tasman forecasts annual GPG usage as high as 16.4 PJ in 2008 (the first year of the AA3 period) to as low as 4.4 PJ in 2010 and around 6–8 PJ in the other years. By contrast, GasNet projects annual forecasts to average 6–7 PJ over the AA3 period.

Table 5.4.7: Forecast of annual gas usage across gas power generators

Year	*Jeeralang*	*Laverton North*	*Newport*	*Somerton*	*Valley Power*	*Total GPG*	*GasNet forecast*	*Difference*
2006	0.7	0.2	6.7	0.5	0.2	8.4		
2007	0.7	6.2	15.9	1.8	7.7	32.3		
2008	0.2	1.1	11.3	0.4	3.4	16.4	6.8	9.6
2009	1.5	0.1	4.5	0.1	0.2	6.4	6.7	–0.3
2010	0.8	0.1	3.4	0.0	0.1	4.4	6.7	–2.3
2011	1.2	0.2	4.5	0.1	0.2	6.2	6.7	–0.5
2012	1.8	0.4	5.5	0.1	0.3	8.1	6.7	1.4

ACIL Tasman's analysis is based on updated information which, in particular, accounts for drought impacts, whereas, the VENCorp/NIEIR analysis was conducted

[372] This is further considered in chapter 6.3 of this draft decision. VENCorp forecasts GPG volumes independently of other volumes and are not represented in the temperature sensitivity (TJ/EDD) calculations. In so far as high EDD outcomes affect high GPG outputs, these volumes are not removed in GasNet's price control formula.

[373] ACIL Tasman, op. cit.

[374] ACIL Tasman concludes that since mid-2006, events in the NEM such as the impact of drought conditions on generator availability and new knowledge as to plant commitments justify a re-examination of the forecast GPG volumes: ibid., pp. 12–14.

ACIL Tasman outlines the critical modelling assumptions and techniques it used to generate the 2008–12 annual demand forecasts and converts expected electricity output back to an implied gas usage. These assumptions include: (1) the latest scheduled energy projections from NEMMCO's *Australia's National Electricity Market 2007 Energy and Demand Projections, Summary Report, July 2007*; (2) constructing a set of hourly loads for a standard year; incorporating generation/interconnector availability assumptions—forecast changes in NEM-scheduled plants over the AA3 period; and (3) forecast reduced annual ouputs from generators associated with water shortages (Snowy Hydro and Tarong).

ACIL Tasman also assumes a comprehensive emissions trading scheme is most likely to occur from 2011 and will replace state-based schemes.

before full effects were known.[375] The ACCC notes also that ACIL Tasman assumes that the likely timing of a comprehensive emissions trading scheme will be from 2011 and that the expectation is that following this (although the effects may not necessarily be immediate) the proportion of GPG output in the electricity sector will increase over time.[376] The ACCC also notes expectations of the advent of emissions trading may trigger the need for potential capital expenditure to meet any increase in GPG proposals.

The ACCC considers the ACIL Tasman forecasts are more likely to represent best estimates arrived at on a reasonable basis than GasNet's forecasts before drought impacts were fully known. The ACCC notes that the impact of these revisions will be to increase volumes over which tariffs will be recovered on the system for the AA period by 6.9 PJ. The impact in 2008 will be to increase the volumes by 8.6 PJ, which is approximately a 3 per cent increase in total volumes. The inclusion of these additional volumes will reduce average tariffs for all users on the system.

The ACCC considers these amendments ensure GasNet and users will bear a symmetrical risk of actual volumes exceeding forecast volumes. On this basis it is not necessary to remove these forecasts from the proposed price control formula as submitted by TRUenergy.[377]

Proposed amendment 12

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 4.2 of the proposed revised access arrangement information to incorporate the annual GPG forecasts in table 5.4.7 of this draft decision.

With the exception of the amendments required above, the ACCC is satisfied that all other GasNet annual volume forecasts taken from VENCorp's 2006 GAPR represent best estimates arrived at on a reasonable basis in accordance with s. 8.2(e) of the code.

5.4.5.4 Exports

GasNet provides its own forecast of exports independently of VENCorp. The ACCC notes the NSW Energy Minister launched the construction of the Uranquinty power plant on 3 August 2007, which GasNet proposes export volumes could service.[378] The ACCC also has considered information received from GasNet as to take or pay arrangements it has or will enter into at the Interconnect up to (or near to) the full capacity of the pipeline. These arrangements may influence users to use this pipeline for exports over AA3 to a greater extent in accordance with allocated rights they

375 National Institute of Economic and Industry Research, *Natural gas consumption and peak day forecasts for Victoria to 2021, Public Version*, December 2006 as quoted in VENCorp, *2006 GAPR*, op. cit.

376 ACIL Tasman, op. cit., p. 14.

377 TRUenergy, op. cit., p. 9.

378 ABC News, *Macdonald launches work on Uranquinty gas-fired power plant*, 3 August 2007, viewed 1 November 2007, <http://www.abc.net.au/news/stories/2007/08/03/1995756.htm>.

have paid for.[379] Accordingly, the ACCC considers GasNet's forecast of annual export volumes represent best estimates arrived at on a reasonable basis in accordance with s. 8.2(e) of the code.

5.4.5.5 Storage refill

GasNet provides its own forecast of storage refill independently of VENCorp. GasNet states that:

> The underground storage facility at Port Campbell has a capacity of approximately 10 PJ. Flows into storage have been as high as 18.3 PJ/annum in 2004, but have since declined dramatically to 0.9 PJ/annum in 2006. It is our understanding that the 2004 flows were essentially exports to South Australia, required because of delays in commissioning of the Minerva gas processing plant. Given that the storage can now be filled with gas taken directly from the adjacent offshore fields, it is expected that only minimal refill volumes will be taken from the PTS. GasNet is projecting volumes of 0.5 PJ/annum. Refill of the LNG facility is usually between 0.1 and 0.3 PJ per annum. GasNet is projecting refill of 0.3 PJ going forward.[380]

However, the ACCC does not consider most recent historical evidence supports the combined annual forecasts of 0.8 PJ of annual refill at WUGS (underground storage) and at the Dandenong (LNG) facility. Further information received from GasNet indicates that up to the end of June 2007, 2.7 PJ and 0.2 PJ of refill gas volume had occurred at WUGS and the Dandenong LNG facilities.[381] This amount is four times the forecast for each year of the AA period and is more consistent with higher volumes in past years before the low year in 2006. The ACCC consider on the basis of information available, despite GasNet's submission comments that refill volumes remain volatile year to year.

The ACCC has considered requiring GasNet to re-justify these forecasts. However, given the unexplained outcomes for early 2007 the ACCC considers that GasNet has not demonstrated it can accurately forecast these volumes in any event meaning that it or users would ultimately bear a risk. The ACCC has considered the fact that GasNet removed refill volumes from its price control formula for AA2 based on volatility. In this regard GasNet stated:

> it is important to note that these forecasts are highly uncertain. GasNet has adopted a tariffing method which charges only the marginal operating cost for refill volumes. Therefore any increase or decrease in refill volumes will be reflected in approximately equal changes in fuel costs.[382]

A consequence of adopting under-forecast refill volume forecasts would be that GasNet would earn any volumes above forecast at an allowed average revenue yield, which is higher than the marginal tariff (cost). The ACCC considers that GasNet's forecasts, which are much lower than historic averages most likely introduce a volume (revenue) upside through their inclusion in the average revenue yield

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379 GasNet, *Email to the AER*, 10 August 2007.

380 id., *Submission*, op. cit., p. 88.

381 id., *Email to the AER*, 31 July 2007.

382 id., *Proposed access arrangement submission 2002–07*, 28 March 2002, p. 108.

control. The ACCC proposes to remove these volumes from the price control, in which case GasNet will still receive a stream of revenue consistent with it recovering its costs, in this instance, the marginal cost of this service, in accordance with s. 8.1(a) of the code.[383]

5.4.5.6 Fuel gas

GasNet provides its own forecast of fuel gas independently of VENCorp. As considered in chapter 5.1 of this draft decision, the ACCC proposes fuel gas to be treated as a pass-through.

5.4.5.7 Distribution of annual and peak withdrawal volumes

The ACCC has audited models allocating volumes to users and identified some issues, which it has discussed with GasNet. GasNet has informed the ACCC it has made changes within its tariff models in response to these issues. The ACCC expects to see these changes within its tariff models prior to making its final decision. In particular, the ACCC has audited the tariff model to ensure that GasNet's normalisation of base year data is such as to achieve an allocation of costs (for both peak and annual usage) to tariff-V (small) and tariff-D (large) users, which is consistent with users being allocated costs in proportion to cost contribution.

5.4.5.8 Peak volumes

In relation to peak withdrawal volume forecasts, the ACCC is satisfied that the VENCorp volumes adopted are best estimates arrived at on a reasonable basis.[384] The ACCC has considered remaining peak forecasts, which have been independently provided by GasNet (exports, storage refill, compressor fuel, GPG). The ACCC notes that:

- 17 TJ/day at Culcairn is consistent with GasNet's forecast capital expenditure proposed for the period and its sale of AMDQ contracts up to (or near to) the capacity of the pipeline to the extent that users choose to flow in accordance with those contracted entitlements[385]
- peak refill and compressor fuel volumes are consistent with historical data provided by GasNet to the ACCC[386] and
- ACIL Tasman considers the 50 TJ/day estimate proposed by GasNet to be not unreasonable, based on historical observations.[387]

Accordingly, the ACCC considers that these forecasts represent best estimates arrived at on a reasonable basis in accordance with s. 8.2(e) of the code.

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383 The proposed amendment is considered in chapter 6.3 of this draft decision.

384 In accordance with s. 8.2(e) of the code.

385 GasNet, *Email to the AER*, 10 August 2007.

386 Data provided by GasNet to the ACCC.

387 ACIL Tasman, op. cit., p. 23.

5.4.5.9 Injection volumes

As considered under GasNet's proposal in chapter 6.3 of this draft decision, the ACCC proposes that GasNet retain top 10 peak day volumes as its basis for charging (and not four month winter volumes). The ACCC proposes not to allow four month volumes to be charged on the basis of these volume forecasts, as the ACCC requires GasNet to levy injection tariffs based on the top 10 peak days. In contrast, to GasNet's proposal where tariffs would have been more distance dependant (and less dependent on volume forecasts), under the ACCC's proposed amendments, top ten peak day volume forecasts at injection sources will be of increased importance in setting initial injection tariffs. That is, users who tend to inject primarily from the Gippsland basin (Longford injection zone) or the Otway basin (Port Campbell injection zone) will face comparative tariffs which strongly reflect top ten peak day volumes forecasts (specific zonal asset group costs/forecast volumes) at these zones.

GasNet comments that there is no independent source of injection volumes, but that it has tested some of its flows against VENCorp system operation requirements in the 2006 GAPR.[388] The ACCC has also tested GasNet's volume assumptions (particularly peak day assumptions) against statements in the 2006 GAPR. The ACCC has reviewed past and forecast annual and peak injection volume data as set out in the table 5.4.8.

Table 5.4.8: Most recent historical and forecast data[389]

	2005	*2006*	*year ending June 07*	*2008*	*2009*	*2010*	*2011*	*2012*
Injection source (Annual PJ)								
Longford (including VICHub)	199.2	191.8	195.5	150	150	150	150	150
Pakenham (continued large scale production started in August 2006	0.3	7.7	16.0	20	20	20	20	20
Port Campbell (Iona and SEAGas facilities)	13.1	21.9	18.9	49.2	51.8	55.2	67.7	59
Injection source (Coincident system peak day volumes TJ)								
Longford	904.2	909.9	937.6	830	830	830	830	830
Pakenham	2	34.0	64.9	67	67	67	67	67
Port Campbell	226.6	158.4	193.3	272	289	303	315	328

* These are the three major injection sources, with other injection sources (Dandenong and Culcairn) forecast to comprise less than 3 per cent of annual / peak volumes.

388 GasNet, *Submission*, op. cit., p. 91. The reference is to flows on the Southwest pipeline from the Otway Basin given the flow limitations due to pipeline capacity.

389 ibid., pp. 89 and 90; GasNet, *Email to the AER*, 31 July 2007 (further historical data).

5.4.5.10 Pakenham

The ACCC considers that early production levels and stated peak day annual production capacity supports the proposed annual and peak day volumes expected to come from Pakenham over the period. VENCorp's 2006 GAPR provides a peak day firm and non-firm supply assumption of 67 TJ/day.[390] The ACCC notes that Origin Energy, a joint venture partner in the BassGas production facility (with significant market share in Victoria through its retailing arm) has purchased this production under a long term-contract and that it has forecast production of over 20 PJ of sales gas annually. The ACCC also notes table 5.4.8 shows in 2006/07, the first year of production, 16 PJ was delivered.[391] Additionally, the ACCC notes that as this injection point is close to metropolitan Melbourne and therefore gas sourced from Pakenham attracts a comparatively small transmission tariff, this increases the competitiveness of BassGas against other sources.

5.4.5.11 Longford/Port Campbell

GasNet proposes a step change down from historic Longford volumes believing that there will be stronger flows of gas from Port Campbell as a result of projects currently in place and being finalised (considered below). This is reflected in a substantial difference between the actual 2006–07 Port Campbell and Longford injection volumes relative to the forecasts that GasNet proposes for 2008–12.

GasNet forecasts account for two significant, presently occurring developments:

- further large amount of gas from the Otway Project (development of Thylacine and Geographe fields off Victoria) being injected into the PTS through the new Woodside facility[392] and
- the commissioning of the Corio loop pipeline.

In relation to the Otway Project, on 17 September 2007 Woodside Petroleum Ltd announced to the Australian Securities Exchange (ASX), that it had started gas exports from the Otway Gas Plant.[393] On 18 October 2007, Origin Energy announced to the ASX that the plant had had some start up issues and steady-state production was anticipated in January 2008.[394]

In relation to the Corio loop, GasNet continues to advise that prior to winter 2008, the Corio loop will have been constructed, increasing the deliverable throughput

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390 VENCorp, *2006 GAPR*, op. cit., p. 24.

391 Origin Energy, *BassGas Project launch—a new source of gas supply for south east Australia*, 16 October 2006, viewed 1 November 2007, <http://www.originenergy.com.au/news/news_detail.php?pageid=82&newsid=711>.

392 GasNet, *Submission*, op. cit., p. 90; Similar figures are published in VENCorp, *2006 GAPR*, op. cit., appendix D.

393 Woodside Petroleum Ltd, *ASX release: Otway Exports First Gas*, 17 September 2007, viewed 1 November 2007, <www.asx.com.au>.

394 Origin Energy, *ASX release: Otway Gas Project—Operator Update*, 18 October 2007, viewed 1 November 2007, <www.asx.com.au>.

from the Otway basin (Otway Project) in time for the winter peak period. GasNet has also informed the ACCC that AMDQ credit certificates have been (or will be) issued up to peak day capacity for this augmentation. These arrangements may influence users to inject from the Otway Basin to a greater extent in AA3 accordance with these allocated rights they have paid for.[395]

The ACCC notes that the recent historical data in table 5.4.8 reveals a greater supply from the Otway Basin, as well as new gas from BassGas. Whilst some reduction in supply from Longford into the PTS has occurred since 2005, the reduction has not as yet been as significant as forecast for 2008–12. The ACCC notes GasNet's submits it can only conject as to the degree of supply from the Otway Basin and Gippsland basin over AA3.[396] The ACCC considers that ultimately the degree of actual basin flow over AA3 will only be revealed over that period and when the Woodside facility (with a full year of production including winter production) and the Corio loop are completed.

The ACCC would expect that retailers and producers would best be able to give a view individually or cumulatively, as to where gas is likely to be injected from as:

- Gippsland Basin producers in addition to directing gas into the PTS, can direct gas through the VicHub into the Eastern Gas pipeline, and Otway Basin producers can direct gas into Adelaide along Sea Gas as well as into the PTS.
- Retailers can choose between Otway Basin gas, BassGas from Yolla near Pakenham and Gippsland basin gas and will factor in amongst other things upstream interests, customer location across the PTS, AMDQ allocations and long term contracts.

However, the ACCC did not receive any submissions from interested parties on GasNet's proposed injection volume forecasts. Market participants may themselves be uncertain as to outcomes prior to the completion of Woodside and the Corio loop. This uncertainty may be enhanced by the fact that the ACCC understands that long term contracts involving the provision of gas from the Longford Basin will expire in 2010 generating further uncertainty about likely price competition which will evolve.

Furthermore, users may have not commented on GasNet injection volume forecasts, believing distance and not injection volume forecasts would be the tariff drivers. However, the ACCC is requiring GasNet to keep its injection tariff approach from AA2. Top ten peak day volume forecasts therefore will be the key tariff driver given costs allocated are to be largely fixed by the respective asset group costs in the Longford, Port Campbell etc injection zones.

Subject to further information (including any submissions to the draft decision), the ACCC considers that:

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395 ACCC meeting with GasNet, 21 August 2007.

396 GasNet, *Submission*, op. cit., p. 90.

- based on the likely completion date of the Corio loop and
- the commencement of the Woodside processing facility

annual and peak injections forecasts represent best estimate forecasts arrived at on a reasonable basis in accordance with s. 8.2(e) of the code. The ACCC has considered GasNet's initial average tariff and proposed increases in capital and non-capital combined with lower forecast volumes and that this necessarily must involve an initial tariff increase for the first year of the period and increased tariffs over the period. Following this draft decision, the ACCC will consider any further evidence which becomes available as to whether GasNet's volume forecasts are reasonable.

The ACCC's intends to the extent possible to ensure that its final decision is based on the most recent information as to Woodside and Corio outcomes. The ACCC also intends to give users a further opportunity to comment in the knowledge that volume forecasts are the primary driver of injection tariffs given the ACCC's required amendments. The ACCC notes in this regard that if the Corio loop or Woodside were to run into (further) start up issues this could strongly affect volumes for 2008.

In accordance with ss. 2.6 and 2.30 of the code, the ACCC proposes GasNet should include top 10 peak days in its AAI contingent on it basing injection tariffs on top ten peak days.

Proposed amendment 13

Before the proposed revised access arrangement can be approved, GasNet must include top-ten peak day volume forecasts for each injection zone in cl. 4 of the proposed revised access arrangement information.

5.5 Revenue

5.5.1 Code requirements

Section 8.4 of the code states that the total revenue is to be calculated by one of three methodologies—cost of service, internal rate of return (IRR) or net present value (NPV). Whichever of these is used, it is to be applied in accordance with generally accepted industry practice.

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 in accordance with ss. 8.30 and 8.31 of the code.

5.5.2 Proposal

GasNet has calculated its total revenue using a building block methodology, which is equivalent to the cost of service methodology under s. 8.4 of the code. GasNet proposes to escalate tariffs from the first year of the period by CPI–X, where X and the initial value of tariffs are set such that the NPV of forecast revenues is equal to the NPV of the building block revenue requirement.[397]

Table 5.5.1 sets out the revenue requirement proposed by GasNet under the building block methodology, and its components, for each year of AA3. It also shows the smoothed forecast revenue for each year.

Table 5.5.1: Proposal—revenue requirement components, forecast revenue

$2006 Dec m	*2008*	*2009*	*2010*	*2011*	*2012*
Return on capital	32.42	37.63	41.86	42.42	42.43
Depreciation	22.53	25.79	28.09	28.58	29.40
Non-capital costs	27.37	26.25	26.03	27.59	29.40
Total revenue requirement	**82.30**	**89.68**	**95.98**	**98.59**	**101.23**
Forecast revenue	**86.18**	**89.77**	**93.79**	**96.87**	**100.55**

Source: GasNet, *Proposed AAI*, pp. 11 and 12 (converted to 2006 Dec $ m).

[397] ibid., p. 83.

Reflecting the capital-intensive nature of gas transmission services, the return on capital is the largest component of the revenue requirement. Similarly, return of capital (depreciation) represents a substantial component of revenue.[398]

The revenue calculation used for the AA2 period is based on an assumption that all cash-flows except for capex take place at the end of the year. In accordance with the ACCC's 2002 final decision for AA2, capex is assumed to occur in the middle of each year and is rolled into the capital base at the end of the year. The capex is increased for six months inflation but is not depreciated nor does it earn any returns before it is rolled into the capital base. GasNet claims that the continuation of this approach will lead to a significant under-recovery of costs for the AA3 period due to its large proposed capex program and because most of its assets are commissioned prior to the middle of the year in order to service winter peak loads. In this context, GasNet proposes to provide depreciation and a return on capital for the six months from when capex is recognised to when it is rolled into the capital base.

GasNet has submitted an illustrative monthly revenue model which it uses to argue that the introduction of a half year return on capital and depreciation would result in an over-recovery of revenues, in NPV terms over the period, by an estimated 0.4 per cent and an under-recovery of 1.9 per cent where these additional returns are not provided.[399] This monthly model applies an adjustment factor to annual revenues under both scenarios to reflect the benefits (in terms of the time value of money) of the monthly revenue cash-flows. GasNet has confirmed that it does not propose to apply this revenue adjustment factor in its actual revenue modelling.[400]

Due to GasNet's tax losses carried forward from prior access periods (calculated for regulatory purposes) it has not claimed any tax liabilities for the AA3 period. GasNet's modelling does indicate, however, that these losses will be fully offset in the AA4 period and it may be able to claim a tax liability in its revenue requirement from this time.

5.5.3 Assessment

5.5.3.1 Revenue timing

As noted by GasNet, the ACCC has previously expressed concerns about recognising capex in the middle of each year as the existing modelling assumptions, whereby cash flows occur at the end of each year, favour the service provider.[401] This benefit arises where actual expenditures and revenues occur relatively evenly throughout the year, and where there is a net positive cash flow (that is, where regulated revenues are larger than expenditures). Nevertheless, the AER in its PTRM and the ACCC in other gas decisions have allowed the introduction of a half-year

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398 GasNet's proposals relating to non-capital costs and depreciation are considered in chapters 5.1 and 3.5 of this draft decision.

399 GasNet, *Submission*, op. cit., p. 85.

400 id., *Email to the AER*, 20 August 2007.

401 id., *Submission*, op. cit., p. 85.

return on capex. For example, the ACCC commented on this issue in its recent decision on the Roma to Brisbane pipeline:

> Recognising capital expenditure as occurring mid year would appear to be inconsistent with recognising the remainder of costs and revenues later. Nonetheless, the ACCC recognises that there is scope to increase the sophistication of its modelling. It also recognises that the ACCC modelled capital expenditure as occurring mid year in its former role as electricity transmission regulator and that the AER currently uses this approach.
>
> In considering APTPPL's submission, the ACCC is mindful that APTPPL has proposed only minor amounts of 'stay-in-business' capital expenditure, and that adoption of mid year recognition in this instance would have little impact on benchmark revenues. On balance, the ACCC has decided to accept APTPPL's proposal. Separate to the current process, it will explore improvements to its modelling to increase sophistication so as to better align the recognition of costs and revenues. [402]

In revising its PTRM, the AER has also indicated it would reconsider its timing assumptions in the future, and may investigate the feasibility of developing a benchmark adjustment to cash flows.[403]

GasNet's claim that capex should be recognised in the middle of the year has merit and is substantiated by historical information contained in its modelling, which indicates that the majority of assets are commissioned prior to the middle of each year. In this context, the ACCC considers it appropriate to adopt GasNet's proposed assumption regarding capex.

Regarding the other cash-flows, the ACCC has reviewed the calculations of GasNet's monthly model and the profiles of opex and revenues contained within it. GasNet's estimate that the current timing assumptions (i.e. all cash flows recognised at the end of the year) result in a potential under-recovery of costs by 1.9 per cent is heavily dependent on a present value adjustment applied to end of year revenue values. That is, the end of year revenue values in the monthly model are reduced by 6 per cent to take account of the benefits of the corresponding monthly revenues received. While it affects the accuracy of the calculation, GasNet does not apply this adjustment factor in calculating its proposed revenue requirement. GasNet's monthly model also contains information on opex that could be used to calculate a similar adjustment factor, although is not used.

The ACCC has used GasNet's monthly model to investigate the accuracy, in terms of revenue recovery in the AA3 period, of the following cash-flow timing scenarios:

- current timing assumptions—all cash flows occur at the end of the year
- GasNet's proposal—recognition of capex mid year, all other cash flows at year end and

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402 ACCC, *Final Decision: Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline*, 20 December 2006, pp. 164 and 165.

403 Australian Energy Regulator, *Final Decision: Electricity transmission network service providers Post tax revenue model*, September 2007, p. 6.

- ‘accurate’ scenario—recognition of capex mid year, revenue and opex monthly (via present value adjustments).

The revenue impacts of these scenarios (including that implied from GasNet’s discussion on its monthly model) are listed in table 5.5.2.

Table 5.5.2: AA3 revenue recovery under cash-flow timing assumptions

Scenario	*Over-recovery NPV for period*	
	%	$ m
Current timing assumptions ▪ Capex (end-of-year) ▪ Opex (end-of-year) ▪ Revenue (end-of-year)	4.3	14.5
GasNet’s actual proposal ▪ Capex (middle-of-year) ▪ Opex (end-of-year) ▪ Revenue (end-of-year)	6.8	22.6
Accurate scenario ▪ Capex (middle-of-year) ▪ Opex (monthly) ▪ Revenue (monthly)	1.6	5.2
GasNet’s ‘current’ modelling assumptions ▪ Capex (end-of-year) ▪ Opex (end-of-year) ▪ Revenue (monthly)	(1.9)	(6.2)
GasNet’s implied proposal ▪ Capex (middle-of-year) ▪ Opex (end-of-year) ▪ Revenue (monthly)	0.4	1.4

Source: ACCC analysis.

Removing the revenue adjustment that is applied in GasNet’s monthly model makes it consistent with the assumptions underlying the current revenue calculation as well as those proposed for the AA3 period. When it is removed, the monthly model indicates that the current timing assumptions would result in an over-recovery of revenue relative to costs by 4.3 per cent in NPV terms over the AA3 period, which increases to 6.8 per cent if a half-year return on capex is introduced. While these results are based on assumed monthly cost and revenue profiles, it demonstrates that the current timing assumptions are biased in favour of GasNet and that its proposal would exacerbate this bias. The ACCC therefore considers that both the current timing assumptions and GasNet’s proposal are inconsistent with s. 8.1(a) of the code.

The ACCC considers that its improvements to the accuracy of GasNet’s revenue modelling are possible through the application of the revenue adjustment factor derived from its monthly model. An adjustment factor should also be applied to opex as the information provided by GasNet indicates that this also occurs evenly throughout the year. No other information has been provided to the ACCC that would justify the need to make similar adjustments to other revenue or cost items, such as tax or dividend payments. In any case, adjustments to these smaller items are unlikely to have any significant effect in relation to the capex, opex and revenue adjustments considered.

The ACCC estimates that the combination of a half year return on capex and present value adjustments to opex and revenue would result in an over-recovery of costs by 1.6 per cent in NPV terms over the AA3 period (or approximately $0.9 m per annum). The ACCC considers that these timing assumptions are internally consistent and produce the best outcome in terms of cost recovery under s. 8.1(a) of the code. GasNet's implied proposal, which results in a 0.4 per cent over-recovery, appears to be more accurate in this regard, although is not considered appropriate as it is based on inconsistent cash-flow assumptions.

5.5.3.2 Authorised MDQ and AMDQ credit certificate revenues

GasNet receives payments through the sale of authorised maximum daily quantity (AMDQ)/credit certificates to users of the PTS. GasNet's procurement and sale of AMDQ/credit certificates is governed by s. 5.3 of the MSO rules and its service envelope agreement (SEA) with VENCorp. AMDQ contracts are offered on a take or pay basis, whereby users pay for a specified contracted capacity. That is, if a user injects or withdraws less than the AMDQ amount, it is still liable to pay for the contracted amount. For usage in excess of the contracted AMDQ amount, users pay for the amount of AMDQ and the excess is charged at the reference tariff.

AMDQ/certificates also provide holders with a hedge against uplift payments (which can be significant) in times of system constraint. The certificates also provide the holder a benefit in terms of priority in the event of load shedding by VENCorp and bidding in the wholesale gas market. The ACCC understands that AMDQ does not represent a firm capacity right. Nonetheless, the demand for AMDQ/credit certificates is likely to be related to capacity constraints and demand for AMDQ/credit certificates would be expected to increase where network constraints arise.

GasNet has indicated that it considers AMDQ to relate to risk mitigation in the wholesale gas market and is not related to the reference service, which involves making the PTS available to VENCorp to operate under the MSO rules.[404] The ACCC, however, considers that the provision of AMDQ/credit certificates is ancillary to the reference service for the same reason. That is, the reference service is provided under the terms and conditions set out in the SEA and the MSO rules which include the administration of AMDQ certificates.

The ACCC has concerns that the existence of AMDQ/credit certificates may result in GasNet over-recovering its revenue requirement. This will occur in two situations:

- if the capacity purchased under AMDQ/credit certificates is not fully utilised, and the unused capacity is allocated to other 'non-AMDQ' users, GasNet is able to generate revenues from selling non-firm capacity rights as well as from selling actual volumes under the market carriage system and
- if the sum of AMDQ contracted amounts exceeds forecast throughput volumes, given tariffs are specifically set with respect to forecast volumes in

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404 GasNet, *Email to the AER*, 10 October 2007.

order to recover the revenue requirement, but are also applied to the AMDQ contracted amount.

With respect to the revenues associated with GasNet's withdrawal tariff, the ACCC estimates the sale of AMDQ will generate an over-recovery of at least $5 m over the AA3 period. This is consistent with GasNet's own estimates that it would earn an amount equal to 1 per cent of revenues from AMDQ certificates, which it considers to be immaterial.[405]

The ACCC expects GasNet to generate additional revenue which has not been quantified (and is difficult to quantify in advance) from AMDQ on two injection zones. In respect of additional revenue from AMDQ credit certificates relating to the SWP or the Corio loop, the incremental amount could be small if peak day usage is at or near to capacity and usage is only by users who hold AMDQ certificates. Alternatively, it could be considerable if non-AMDQ credit certificate holders cause a lot of gas to flow on peak days. This may mean GasNet will receive revenue from AMDQ holders (up to revenue associated with near capacity volumes) plus further revenue associated with non-AMDQ holder volume flows.

The ACCC proposes an amendment to GasNet's proposed AA to account for AMDQ revenue within GasNet's price control formula.[406]

GasNet notes that the MSO rules do not mandate the issuance of AMDQ/credit certificates and that the ACCC's proposed treatment would remove any incentive for it to issue authorised MDQ and AMDQ credit certificates. Given the ACCC views AMDQ and AMDQ credit certificates as beneficial for market participants, it intends to allow GasNet to propose any additional operating costs associated with issuing and administering these authorised MDQ and AMDQ credit certificates. Accordingly, the ACCC invites GasNet to propose any additional operating costs in response to the draft decision.

5.5.4 Conclusion

The ACCC's assessment of GasNet's proposal is that various elements of its proposed costs do not comply with the requirements of the code. Accordingly, the ACCC proposes a number of changes to be made to these costs, which requires an amendment to GasNet's proposed total revenue. The ACCC's estimate of the resulting revenue requirement is outlined in table 5.5.3.

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405 ibid.

406 This is set out in chapter 6.3 of this draft decision.

Table 5.5.3: Draft decision—revenue requirement components, forecast revenue

2006 Dec $ m	*2008*	*2009*	*2010*	*2011*	*2012*
Return on capital	35.58	36.70	36.61	35.54	34.46
Depreciation	22.73	23.97	24.28	24.11	24.20
Non-capital costs	24.36	20.95	20.86	21.61	23.03
PV revenue adjustment	–2.08	–2.06	–2.06	–2.05	–2.06
Total revenue requirement	**80.58**	**79.56**	**79.70**	**79.21**	**79.63**

Source: ACCC analysis.

Proposed amendment 14

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.7 of the proposed revised access arrangement information to reflect table 5.5.3 of this draft decision.

6 Reference tariffs

6.1 Cost allocation and tariff structures

This chapter of the draft decision first outlines GasNet's current reference tariffs for the AA2 period and the methodology used to allocate costs to tariff zones and to derive these tariffs. GasNet's proposed changes for the AA3 period to its reference tariffs and cost allocation methodology is then summarised. This chapter also considers GasNet's proposed changes to its allocation of direct costs is considered followed by an analysis of the allocation of indirect costs, including the carryover K-factor. This section also considers the implications of GasNet's proposed cost allocation methodology for those assets (investments) approved under the economic feasibility test. Consideration is then given to GasNet's proposed changes to its reference tariffs, including the tariff-V withdrawal tariff, peak injection tariff, the application of prudent discounts and the introduction of a new tariff zone.

6.1.1 Code requirements

Section 8.38 of the code requires that, to the maximum extent that is commercially and technically reasonable, reference tariffs should recover costs directly attributable to the reference service and a fair and reasonable share of costs incurred jointly with other services. Section 8.42 of the code also requires that the recovery of a particular user's share of costs also follows these principles. These requirements must be met, regardless of the methodology used to calculate total revenue. In addition, the code requires the relevant regulator to take into account the objectives set out in s. 8.1 of the code. However, if the s. 8.1 objectives conflict, the relevant regulator must also consider the elements in s. 2.24 of the code, (which include amongst other things, the service provider's legitimate business interests, the interests of users, and the public interest) to assist in resolving that conflict.

An exception to the objectives in s. 8 of the code is the case of prudent discounts. If a user or prospective user would not be a user at the reference tariff, s. 8.43 of the code 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 higher tariffs for 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.

6.1.2 Current access arrangement provisions

6.1.2.1 Current reference tariffs and structure

Under the provisions GasNet's second access arrangement (AA), costs are recovered through three main reference tariffs:

- *Anytime withdrawal tariffs* on the actual quantity of gas delivered over the calendar year. Different rates apply for tariff-D and tariff-V volumes which reflect different use of the system by users. Tariff-V applies to customers consuming less than 10 000 GJ per annum and tariff-D applies to customers with annual consumption greater than 10 000 GJ or a maximum hourly demand greater than 10 GJ.

Tariff-V and tariff-D users are further split into one of 16 withdrawal tariff zones and different tariff-V and tariff-D rates apply for each of the 16 withdrawal charging zones. The rates applying to each withdrawal charging zone reflect the use of system assets to deliver gas to the zone, the distance of the zone from the injection source and the volume withdrawn in the zone.

- *Peak injection tariffs* apply to each of the injection zones (Longford, Culcairn, Port Campbell and Pakenham) on the actual quantity of gas injected on behalf of the user on the 10 highest injection demand days over the peak period (June to September). There is no differentiation between tariff-D and tariff-V volumes.
- *Storage refill tariffs* for gas injected into storage, charged at the marginal cost (which is the cost of compressor fuel at the appropriate compressor station).

In addition to the above reference tariffs GasNet also applies tariffs to reflect specific costs relating to the use of the PTS. These include:

- *A cross-system tariff* which applies in addition to the applicable injection and withdrawal tariff for carriage through the Metro zone. It applies for withdrawals off the injection pipeline which are linked to injections at an unrelated injection point.
- *Matched rebates* for reference tariffs matched to injections and withdrawals where users do not utilise the entire injection or withdrawal pipelines. The matched rebates are designed to convert relevant tariffs into cost-reflective tariffs which reflect the direction of supply. Rebates are matched to injection tariffs for zones close to Longford, including Latrobe, Lurgi, Tyres and West Gippsland. Rebates are also matched to injection charges applying to Interconnect zone users who inject at Culcairn and South West and Western zone users injecting at Port Campbell.

Matched rebates also apply to withdrawals from North Hume, Murray Valley, Interconnect and Wodonga zones for gas injected at Culcairn which reflects the shorter associated transportation distances. A matched withdrawal tariff also applies to the Metro South East zone for withdrawals from Pakenham.

For AA2, GasNet also applied prudent discounts for several tariffs to minimise the threat of bypass risk. These include:

- the withdrawal tariff at Wodonga for gas matched to injections at Culcairn
- withdrawal points within the Metro zone which are close to Pakenham for gas matched to injections at Pakenham. This was done by creating a new withdrawal zone, Metro South East
- 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.

6.1.2.2 Current cost allocation methodology

GasNet derives its reference tariffs using a cost allocation model (tariff model). This model allocates direct costs (capital and operating) to both withdrawal and injection tariff zones and indirect costs (e.g. general and administrative operating costs) only to withdrawal tariff zones. GasNet's injection tariffs recover the direct costs based on transporting gas along the injection pipeline. The withdrawal tariffs recover the direct costs of transporting the gas from the end of the injection pipeline along the withdrawal pipeline to the off-take points as well as a proportion of GasNet's indirect costs allocated on a postage stamp basis.

To derive injection tariffs, the direct costs associated with each injection pipeline segment are allocated directly to that pipeline and no indirect costs are allocated to injection pipelines.

The derivation of withdrawal tariffs is based on an allocation of direct costs which reflects the forecast of gas flows (i.e. physical flow-path of gas) and the assets used to transport the gas through different segments of the withdrawal pipelines to the final withdrawal zones.

The cost allocation methodology is outlined in more detail below.

(i) ***Direct cost allocation***

To allocate direct costs to injection and withdrawal charging zones, the direct capital costs (return on and return of capital and capital raising costs) associated with all pipeline, regulator and compressor assets of the GasNet system are allocated among the 28 pipeline segments. This apportionment is in proportion to the optimised replacement cost of each asset within the segment (i.e. asset group). The 28 asset groups are defined physically (e.g., changes in pipeline diameter).

Direct operating costs are allocated to each asset group according to the pipeline length and whether the pipeline is located in a metropolitan or country area. Direct operating costs associated with city gates, regulators and compressors are allocated directly to the relevant asset group.

Once the direct costs (capital and operating) have been allocated to asset groups they are then further allocated to each withdrawal off-take within a tariff zone based on the forecast physical flow path of gas through each asset group and to injection pipelines directly based on the asset groups associated with each injection pipeline.

To allocate direct costs to withdrawal off-takes, GasNet calculates a direct cost unit recovery rate ($/TJ-km) for each asset group. That is a specific direct cost unit rate applies to each asset group. To do this GasNet first determines the peak and annual flow path of gas from the injection points to each off-take point.[407]

[407] To determine the peak and annual flow to each off-take GasNet uses a satisfaction sequence. Under this sequence each off-take can potentially receive gas from one or two of five injection points. The order is largely determined by distance, so the off-takes closest to an injection point

Once the flow path of gas is determined for each off-take, GasNet is able to derive peak and annual direct cost unit rates for each asset group based on the:

- direct costs allocated to that asset group ($)
- volume of gas flowing through each asset group (TJ) and
- distance of pipeline segment in each asset group (km).

This direct cost unit rate ($/TJ-km) is used to assign costs to each off-take as gas flows through each asset group from the end of injection pipeline to the off-take.[408]

In general, under this methodology, the further the gas flows to an off-take the more asset groups its passes through and the more costs it picks up and hence the more costs assigned to the off-take. Accordingly, a user who uses a short section of the pipeline will, in general, pay a lower cost than a user who uses a longer section of the pipeline.

Under GasNet's current tariff model 45 per cent of the direct costs associated with withdrawal assets are allocated according to peak volume flows and 55 per cent according to annual volume flows.[409]

For injection pipelines, the direct costs associated with each injection pipeline segment are allocated directly to the injection pipeline.

(ii) *Indirect cost allocation*

Indirect costs are allocated to withdrawal charging zones only after the allocation of direct costs and are allocated to on a $/GJ postage stamp basis. The indirect cost component of tariffs aims to recover the transmission system indirect costs as well as a portion of costs for assets that are identified to have system-wide benefits (i.e. 'rolled out' cost). Indirect costs consist of:

- capital costs of non-system assets
- general and administrative operating and maintenance costs
- benefit sharing carryover allowance to be applied from 2008
- asymmetric risks and
- Interconnect costs (92 per cent) and Southwest pipeline costs (SWP) (50 per cent).

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are deemed to receive gas from that point or, if all gas is accounted for, from the next closest point, but not until other off-takes closer to that point have been satisfied.

408 For example, if a flow to a withdrawal off-take passes through two asset groups, and comprises 1 per cent of the total flow through the first asset group and 3 per cent of the flow through the second asset group, then that off-take would receive 1 per cent of the first asset group's cost recovery and 3 per cent of the second asset groups cost recovery, assuming the distance of each asset group is the same.

409 ACCC, *Final Decision: GasNet Australia access arrangement revisions for the Principal Transmission System*, 13 November 2002, p. 231.

For AA2, indirect costs were allocated on a postage stamp basis to all withdrawal zones, except for the Western Transmission System (WTS), which does not include the ‘rolled out’ component. Furthermore, indirect cost discounts are applied to the Latrobe, Western and Wodonga withdrawal zones to reduce the threat of bypass risk. To recover the discounted amount, the indirect costs allocated to the remaining withdrawal tariffs are equally scaled up.

For AA2, the unrecovered K-factor adjustment between the AA1 and AA2 periods (carryover K factor) is allocated on a uniform percentage basis to all tariffs except those for the SWP (Port Campbell injection tariff) and the MVP (Murray Valley withdrawal tariff).

In summary, costs are grouped into the following categories and allocated as shown in the table 6.1.1.

Table 6.1.1: Summary of cost allocation procedures

Cost category	*Allocation method*
System assets (direct capital costs)	Physical path
Direct operating costs	Physical path
Costs rolled in under the system-wide benefits test	Postage stamp
50 per cent SWP costs	Direct to zone
Interconnect zone residual costs	Direct to zone
Non-system assets (return on and of capital)	Postage stamp
General and administrative costs	Postage stamp
Overheads reduction	Postage stamp
Return on working capital (linepack and inventories)	Postage stamp
Benefit sharing allowance	Postage stamp
K-factor carryover	Uniform percentage basis
Asymmetric risk	Postage stamp

Source: GasNet, *Submission 2008–12*, schedule 5.

(iii) *Derivation of withdrawal tariffs*

Once direct costs have been assigned to each withdrawal off-take, the off-takes are aggregated into one of 16 withdrawal tariff zones and average zonal tariffs for tariff-V and tariff-D users are calculated. Tariff-V and tariff-D zonal tariffs are derived by summing the cost allocations to V users and D users for each off-take in the zone and dividing by the total V and D volumes withdrawn by off-takes in the zone. The average of the costs for all meters for both V and D volumes within a tariff zone represents the charge against direct costs at the zonal level. As noted above, the indirect costs are allocated on a postage stamp ($/GJ) basis to zonal withdrawal tariffs, with the exception of the Western Transmission System (WTS).

(iv) *Derivation of injection tariffs*

Injection tariffs are derived by assigning the direct costs associated with each injection asset group to the relevant injection pipeline and dividing by the forecast top 10 peak day flows for that injection pipeline. No indirect costs are added to injection tariffs, except for a proportion of the K-factor.

(v) *Exceptions to the standard cost allocation model*

Under GasNet's second AA, the costs for the SWP, Interconnect, and the Murray Valley pipeline (MVP) are allocated separately to GasNet's standard cost allocation methodology. For the Southwest pipeline (SWP) 50 per cent of the costs are allocated directly to that asset in accordance with the economic feasibility test and are recovered through the Port Campbell injection tariff. 50 per cent are allocated under the systems wide benefits test and accordingly allocated across all withdrawal tariffs on a postage-stamp basis. In addition, for AA2 the ACCC considered, in relation to the sustainability of charges on the SWP, that the Port Campbell injection tariff should be approximately 10 per cent higher than those on the Longford to Pakenham pipeline.[410]

The majority of the Interconnect costs are allocated on a postage-stamp basis across all withdrawal tariffs. While the remaining 'residual' costs of the Interconnect (8 per cent of the total) is allocated directly to that asset (i.e. the Culcairn injection tariff).

Withdrawal tariff-V and D users of the Murray Valley pipeline (MVP) are charged withdrawal tariffs that consist of two components. The first component (Chiltern Valley) recovers the cost of withdrawal pipeline usage up to Chiltern Valley and is calculated in accordance with GasNet's standard cost allocation methodology. The second component, the incremental tariff (Murray Valley), is designed to recover the stand alone costs associated with the MVP as required by the economic feasibility test.[411] In addition, 75 per cent of the costs of Murray Valley tariff are allocated on the basis of peak usage (instead of 45 per cent as per GasNet's standard cost allocation model for withdrawal tariffs).[412]

6.1.3 Proposal

GasNet proposes a number of changes to the structure of its reference tariffs and to its cost allocation methodology for deriving tariffs. In general, GasNet's proposed cost allocation methodology and reference tariff structure results in a greater averaging of costs across the PTS. GasNet also proposes not to re-apply a number of its prudent discounts, which applied during AA2. GasNet's proposals are outlined below.

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410 ibid., p. 65.

411 This is based on the ACCC's decision for AA1, that new extensions which enter the capital base are to be assessed against the economic feasibility test:

> …at the scheduled reviews, tariffs should be calculated in such a way that they fully recover the costs associated with the assets (that is, their tariffs should not be derived from the general cost allocation methodology.

412 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 234.

6.1.3.1 Reference tariffs and structure

GasNet proposes to retain both injection and withdrawal tariffs and the current separation of withdrawal tariffs for tariff-V and tariff-D users, but proposes to change the manner in which the tariff-V withdrawal tariffs and the injection tariffs are charged.

In summary, GasNet proposes the following reference tariffs in AA3:

- to maintain zonal withdrawal tariffs for tariff-D users, with the exception of an additional zone at Geelong (separated from the current Metro zone).[413] GasNet also proposes two new western zones for tariff-D users (Warrnambool and Koroit). These zones have been separated from the current Western zone and a prudent discount applied to these zones to remove the threat of bypass[414]
- to maintain a withdrawal tariff for tariff-V users, but to remove zonal boundaries and apply a single postage stamp tariff-V to all tariff-V users[415]
- to maintain injection tariff zones for each injection pipeline, but to levy the tariff for each injection pipeline levied on actual volumes injected during the winter period (June to September). Instead of on the top 10 peak injection days for each injection pipeline as is currently the case.[416]
- to continue to charge the storage refill tariffs. For the underground storage at Port Campbell, GasNet proposes a marginal cost of \$0.20/GJ and for refill of the LNG Storage Facility, a marginal cost of \$0.15/GJ[417]
- to continue to apply the cross-system tariff for withdrawals off the injection pipeline, which are linked to injections at an unrelated injection point[418]
- to maintain matched injection tariff rebates for reference tariffs matched to injections, where users do not utilise the entire injection or withdrawal pipelines[419]
- to maintain matched withdrawal tariffs for tariff-D users only for the northern zones (North Hume, Murray Valley, Interconnect and Wodonga) for users who inject at Culcairn. However, matched rebates will no longer apply to tariff-V users[420]

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413 GasNet, *Access Arrangement Submission 2008–12*, 14 May 2007, p. 94.

414 ibid., p. 103.

415 ibid., p. 96.

416 ibid.

417 ibid., p. 102.

418 GasNet, *Proposed Access Arrangement 2008–12*, 14 May 2007, sch. 1; p. 20.

419 ibid., p. 23.

420 ibid.

- to maintain a prudent discount for tariff-D customers at Pakenham, but to remove:[421]
  - all prudent discounts currently applied to tariff-V users as a single tariff-V is proposed for all V users
  - prudent discounts currently applying to users in the Latrobe and Wodonga zones and
- to apply a Culcairn export tariff of $0.50/GJ.[422]

6.1.3.2 Cost allocation methodology

GasNet proposes to retain the current allocation of indirect costs on a postage stamp basis to withdrawal tariff zones, but to change the methodology for allocating direct costs to withdrawal tariff zones and injection tariff zones. In particular, GasNet is proposing to allocate direct costs to both withdrawal and injection tariff zones based on average direct cost unit rates. This is to replace the current allocation of direct costs using asset group specific direct cost unit rates.

(i) *Direct cost allocation*

Under GasNet's proposed methodology the same (average) direct cost unit rate ($/TJ-km) will be applied to each asset group, irrespective of the optimised replacement cost of the pipeline segment or the capital expenditures allocated to that segment. One rate applies for peak flows, and another for annual flows.[423] A separate rate is calculated for the injection pipelines as a whole and for the withdrawal pipelines as a whole.

Under GasNet's proposed methodology, the direct costs allocated to a withdrawal zone (for tariff-D) will therefore depend on the distance of the zone from the end of the injection pipeline and the volume withdrawn in that zone. For the injection pipelines the direct costs allocated to the injection pipeline will depend on the distance of the pipeline and the volume transported along the pipeline.

This differs from GasNet's AA2 methodology for allocating costs to withdrawal zones where specific peak and annual direct cost unit rates are calculated for each withdrawal pipeline segment (asset group). These direct cost unit rates for each asset group reflect the value of assets associated with that specific asset group, the flow of gas through the asset group and the length of the pipeline segment within the asset group (i.e. $/TJ-km for each asset group).[424] The costs allocated to the final withdrawal tariff charging zones, therefore reflect the costs of each of these asset groups/pipeline segments along which gas flows from the end of the injection pipeline to withdrawal zone.

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421 GasNet, *Submission*, op. cit., p. 103.

422 ibid.

423 ibid., p. 95.

424 The value of each pipeline segment is based on the optimised replacement cost of each segment.

GasNet also proposes replacing its AA2 methodology of allocating direct costs associated with each injection pipeline directly to the pipeline. In particular, GasNet proposes for AA3 that average direct cost unit rates based on peak and annual volumes be used to allocate cost to each injection pipeline. That is, the same unit rate ($/km/GJ) will be applied to each asset zone, irrespective of the cost of the pipeline segment or the capex allocated to the segment. There will be one rate for peak flows and one rate for annual flows.[425]

GasNet proposes to amend the allocation of costs between peak and annual flows in the new tariff model to address the fact that the PTS is now more constrained than over the last five years.[426] To achieve this GasNet proposes to allocate the direct costs associated with withdrawal assets, such that 65 per cent of the direct costs will be allocated according to peak volume flows (instead of the current 45 per cent) and 35 per cent allocated according to annual flows (instead of the current 55 per cent).[427]

GasNet also proposes to allocate direct costs associated with injection pipelines on the same basis.[428] This differs from AA2, where the direct costs associated with each injection pipeline are allocated directly to the pipeline.

(ii) *Indirect cost allocation*

For AA3, GasNet proposes that the indirect costs consist of:

- a portion of the Interconnect (92 per cent), Southwest pipeline (50 per cent) and Brooklyn Lara/Corio loop (100 per cent) assets. That is, those assets identified as having system-wide benefits, (referred to as 'rolled out' costs)
- general administrative operating and maintenance costs
- compensation for asymmetric risk and
- benefit sharing allowance.[429]

This is consistent with AA2, except for the addition of the proposed 100 per cent roll out of the Brooklyn Lara-Corio loop costs.

GasNet proposes to continue to allocate indirect costs on a postage stamp to all withdrawals zones, with the exception of Western, Warrnambool and Koroit zones which are not allocated any 'rolled out' costs. In particular, the Western zone is not allocated rolled-out costs because it does not benefit from these system-wide benefits as approved by the ACCC for AA2.[430] For AA3, Warrnambool and Koroit are two proposed new tariff-D withdrawal zones split from the current western zone and GasNet does not propose to allocate any indirect costs.

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425 GasNet, *Submission*, op. cit., p. 95.

426 ibid.

427 ibid., p. 96.

428 ibid.

429 Supporting tariff models provided by GasNet to the ACCC.

430 GasNet, *Email to the AER*, 26 June 2007.

GasNet proposes that the Murray Valley, Wodonga, North Hume and Interconnect zones supplied from the south are not allocated indirect costs, since these zones are otherwise too heavily burdened.[431]

GasNet further proposes that tariff-D users in Warrnambool are given a discount of 76.5 per cent to the indirect costs allocated to this zone based on bypass risk from the SEA Gas pipeline.[432] The indirect costs allocated to the other tariff-D withdrawal zones are scaled up equally to recover this discount.

GasNet proposes that the carryover K factor between AA2 and AA3 is allocated on a uniform percentage basis to all tariff zones with the following exceptions:

- the Murray Valley, North Hume, Wodonga and Interconnect withdrawal zones sourced from South and the Echuca and South West withdrawal zones and
- the Port Campbell injection tariff and the Pakenham injection tariff.[433]

6.1.3.3 Tariff derivation—proposal summary

To derive tariffs for each withdrawal tariff charging zone, GasNet proposes to calculate an average peak and annual direct cost unit rate. These direct cost unit rates ($/TJ-km) are used to allocate direct costs to each off-take according to the distance to the off-take from the end of the injection pipeline, and the peak and annual flow to the off-take. The allocation of costs based on the physical flow path of gas is consistent with GasNet's AA2 methodology for withdrawal tariffs. The difference is that an average peak and annual direct cost unit rate of all withdrawal asset groups is used instead of individual direct cost unit rates for each of the 28 asset groups.

Once these unit rates are calculated, the direct costs are further allocated to final tariff-D and tariff-V withdrawal charging zones according to the forecast of annual and peak flows for tariff-D and tariff-V at the off-takes in the tariff charging zone and the distance from the end of the injection pipeline to the tariff zone

(i) *Withdrawal tariff-D*

GasNet proposes to retain the current charging zones for tariff-D users in AA3 and introduce two additional tariff zones. GasNet proposes to derive tariff-D by dividing the allocated direct costs and indirect costs by the forecast annual tariff-D volume in each zone.[434]

(ii) *Withdrawal tariff-V*

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[431] ibid.

[432] ibid.

[433] ibid.

[434] ibid.

GasNet proposes to remove the existing 16 charging zones for tariff-V and introduce a postage stamp tariff for V users in AA3. To derive the postage stamp tariff-V, GasNet proposes to divide the sum total of the direct and indirect costs allocated to tariff-V in each withdrawal zone by the total PTS tariff-V annual volume.[435]

(iii) *Injection tariffs*

GasNet proposes to derive average annual and peak direct cost unit rates to allocate direct costs to each injection pipeline based on the distance of the pipeline and the volume injected on the pipeline.[436] This is the same concept as proposed for withdrawal pipelines for AA3. However, this differs from GasNet's current cost allocation methodology, where direct costs associated with each injection pipeline segment are allocated directly to the pipeline. GasNet also proposes that no indirect costs to be allocated to the injection pipelines, which is consistent with the second AA.

In addition, GasNet proposes that the injection charge be levied on the injections over the peak winter period being June to September. GasNet therefore proposes to derive the injection charge by dividing the allocated cost to each injection pipeline by the forecast winter peak period injections for that injection pipeline.[437] This differs from the second AA, where the injection charge is levied on the top 10 peak days during June to September and is derived based on the forecast volume of the top 10 peak days.

6.1.4 Submissions

Submissions generally stated that GasNet's proposed cost allocation methodology and postage stamp tariff for tariff-V users would result in less cost reflective tariffs and be less consistent with the requirements of s. 8.1 of the code.

Submissions also expressed concern over the 30 per cent average increase in tariffs. Australian Paper, in particular comments that it will experience a 160 per cent increase in gas transmission charges despite not having changed its gas consumption profile over the last five years and having no plans to change over the next five years.[438]

In general, the ACCC was requested to consider the benefits associated with GasNet's proposal as well as the implications against the requirements of the code. Origin Energy, for example, requests the ACCC to carefully evaluate the proposal in the context of requirements of s. 8.1 of the code and, in particular, any impact on the efficiency of investment decisions in the absence of specific pipeline cost allocation.[439]

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435 ibid.

436 ibid.

437 ibid.

438 Australian Paper, *Submission to the issues paper*, 29 June 2007.

439 Origin Energy, *Submission to the issues paper*, 9 July 2007, p. 3.

Origin Energy queries whether GasNet's proposal to adopt a postage stamp for tariff-V customers meets the specific code requirements using the example of how this might impact on decisions around a new 'Murray Valley' type extension. Origin Energy comments that:

> it does not oppose the approach put forward by GasNet, but questions the consistency of postage stamp pricing with the type of pricing signals that might be desirable if there is an intention to reflect the cost of augmentations and extensions to the PTS.[440]

AGL submits that a consequence of the proposal for a postage stamp tariff-V is that the Murray Valley incremental transmission tariff, which presently applies to off-takes on the Murray Valley lateral from Chiltern, will now be absorbed into the general tariff for V customers. But can accept this consequence as a result of a move towards a uniform withdrawal tariff.[441]

The EUCV comments that some of the assets in the PTS and SWP are seen to provide increased security of supply of gas to Victorian consumers. However, the assumption is made that all Victorian gas consumers will benefit from this increased security. The EUCV states that some of its members will, in the event of a major gas shortage, be constrained off gas supply. The EUCV questions whether tariffs for large gas consumers should be discounted as they are unlikely to benefit from increased gas security by gas now being supplied from southwest Victoria and Culcairn.[442]

Overall TRUenergy and AGL are supportive of GasNet's proposal to reduce the cost reflectivity of tariffs. The main arguments for this position include:

- administratively easier
- transmission price signals are not passed through to end-uses and
- positive impact on rural customers.

(i) *Effectiveness of price signals*

TRUenergy comments that:

> Retailers offer gas to its customers on a bill that includes an individual transmission component that reflects an amalgamation of our transmission costs priced at the retail pricing zone. In this sense, they smear the costs to each customer priced in each of the retail pricing zones that it services.
>
> As a result of this, the pricing signals embedded in any tariff developed by GasNet would be lost. Accordingly, there is limited value in designing a tariff regime that sends the 'right' pricing signals for gas transmission tariffs, when retailers subsequently amalgamate and smear gas transmission tariffs at a zonal level.[443]

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440 ibid., p. 4.

441 AGL, *Submission to the issues paper*, 26 June 2007, p. 2.

442 Energy Users Coalition of Victoria, *Submission to the issues paper*, 10 August 2007, p. 18.

443 TRUenergy, *Submission to the issues paper*, 27 June 2007, p. 5.

Origin Energy, on the other hand submits that while it may be the case, that most retailers amalgamate the PTS transmission tariff zones for the purpose of marketing gas, in order to save administrative costs, that:

> each retailer will make such a judgement depending on their own commercial objectives and systems, and such amalgamation may take place to a greater or lesser extent. Therefore, the discretion retailers may apply in simplifying transmission tariffs will vary and of itself should not be considered justification for change.[444]

Origin Energy also expressed concern regarding the impact upon users of the PTS of continual change in the structure of underlying tariffs, and the costs to retailers of altering information technology systems and factoring in the uncertainty generated by changes initiated at the beginning of each new AA period. Origin Energy contends that continual and fundamental change is not in the interests of users of the PTS.[445]

(ii) *Promotion of market for reference services*

TRUenergy submits that the market for gas reference services will develop and expand in western Victoria under tariffs proposed in AA3 consistent with s. 8.1(f) of the code. In contrast, TRUenergy also comments that:

> … tariff increases for customers located in western Victoria under zonal gate tariffs would be dramatic compared with the current tariffs proposed for AA3. This would affect the ability of gas to compete as a viable alternative fuel in western Victoria. Industries reliant on gas as an input cost located in the area would be impacted, with many losing competitive advantage.[446]

TRUenergy submits that major tariff increases would be inconsistent with the State Government's policy and its recent efforts. TRUenergy supports the current tariff proposal because it avoids tariff shock, represents a sensible policy direction and delivers a more balanced outcome for users of the PTS.[447]

With respect to the cross subsidies from metro zones to rural zones as a result of GasNet's proposal, TRUenergy comments that in general, cross subsidies are only anti-competitive if they decrease competitive pressure in the areas in which they are applied and involve the leveraging of an incumbent monopoly position. TRUenergy argues that there is no evidence to suggest this is the case and, it is clear that the cross subsidised tariff in AA3 have been implemented to avoid tariff shock for rural customers and to simplify tariffs. On this basis TRUenergy comments that tariffs are efficient.[448]

TRUenergy also comments that tariff increases for customers located in western Victoria under zonal gate tariffs would be dramatic compared with the current tariffs proposed for AA3. Given the relatively elastic nature of gas in rural and regional

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[444] Origin Energy, op. cit., p. 4.

[445] ibid., p. 2.

[446] ibid., p. 4.

[447] ibid.

[448] ibid., p. 5.

areas, tariffs produced in AA3 under a zonal gate methodology would lead to a substantial reduction in throughput volumes from assets located in western Victoria, as customers switch to substitute products. This would lead to a significant under-recovery of revenue for GasNet from rural assets located in western Victoria.[449]

AGL comments that given the regional/country load is 20 per cent of the total load and given the percentage accounted for by gas transmission in the retail cost structure, this impact on metro customers will be seen as tolerable. AGL, comments that it is comfortable with the proposal for a single withdrawal tariff for tariff-V customers.[450]

Origin Energy comments that whilst GasNet's argument that the benefits of a simple tariff structure to retail competition outweighing the relatively small economic efficiency benefits of a complex zonal structure for tariff-V customers is persuasive, at the margin the increase in the cost of tariff-V withdrawals will be significant on a relative basis.[451]

Origin comments that with respect to GasNet's suggestion that the benefits of a simple tariff structure to retail competition outweighing the relatively small economic efficiency benefits of a complex zonal tariff structure for tariff-V customers, that:

Origin agrees that practically, this argument is persuasive; however we note that at the margin (in spite of the "cost of gas being a relatively small proportion of the total household budget") the increase in cost for Tariff V withdrawals will be significant on a relative basis. For example, withdrawal tariffs in Gippsland zones may double for some of Origin's Tariff V customers through the application of postage stamp pricing.[452]

(iii) *Injection tariff structure*

AGL and TRUenergy support the move towards a simpler injection tariff based on winter volumes rather than on the 10 peak days over winter as is the case for AA2. AGL comments that:

> Currently the 10 peak winter days and the magnitude of injections on those days are not known until October/November each year. A rate that is applied to winter volumes, as proposed, will provide greater billing certainty for retailers and customers on pass-through retail tariff arrangements. This will help eliminate residual billing problems that we currently experience with tariff-D customers, owing to the uncertainty of the quantum. This becomes more problematic when customers churn away before the final winter wash-up is completed.
>
> Whilst it may be argued that this move away from pricing on 10 peak winter days, results in some loss of the strength of price signals, retailers would feel that the administrative simplicity and billing certainty would be beneficial in net terms.[453]

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[449] ibid., p. 4.

[450] AGL, op. cit., p. 2.

[451] Origin Energy, op. cit., p. 4.

[452] ibid., pp. 4 and 5.

[453] AGL, op. cit., p. 3.

TRUenergy comments that as retailers are unable to measure the volumes that apply to peak injection charges on a daily basis, they are unable to pass these costs through to individual customers. Accordingly, any pricing signals embedded in the 10 peak day charges would also be lost when priced at the retail level. TRUenergy further submits that:

> … the 10 peak day tariff structure has the perverse effect of deterring injections into the market during those times when gas is most valuable. As a result of the current 10 peak day injection tariff, delivery chain costs are artificially increased when the wholesale market is stressed. This, together with the retrospective application of the 10 peak day injection charges, makes wholesale market risk difficult to manage. Whilst injection tariffs can be ignored by Retailers that seek to supply gas to their own customers under the current access regime, these charges become real costs for those participants who are "long" on the 10 peak injection days.[454]

The EUCV, however, comments that the logic of the approach to move from demand related to the 10 highest injection days to an 'all of winter' demand is for simplification reasons.[455] The EUCV notes that:

> this is a trend away from the AEMC review for electricity where the AEMC considers that a more cost reflective tariffs will result from moving from a long term basis to one representing the highest demands experienced. The logic of the AEMC revolves around the principle that as investment is related to the highest demand on the system (i.e. the system is built to manage the highest daily—even hourly gas usage) then the most cost reflective tariffs must be set based on peak usage, and not on average usage.
>
> A move to average usage results in less cost reflectivity, and increases greater cross subsidisation from high load factor users to low load factor users.[456]

The EUCV also comments that:

> There is significant expansion of the gas transmission system being proposed to accommodate the short term demands placed on the gas system by gas fired generation. Historically large gas consumers have had a high load factor for their gas usage, yet the impact on seasonal gas demand for electricity generation, has resulted in a gas transport system which is now sized to manage a significantly more volatile gas demand.
>
> This volatility is not caused by large customers yet they are expected to pay for assets to allow for this increase. As they do not cause the need to accommodate these short term but high peaks in demand, it is questioned whether there is need for introduction of gas transportation tariffs which are related to usage by those users who impose high but transient demand on the network.
>
> The approach by GasNet seems to be a "one size fits all" approach which provides a windfall benefit to high but transient (low load factor) users of the network to the detriment of the high load factor users.[457]

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[454] TRUenergy, op. cit., p. 6.

[455] Energy Users Coalition of Victoria, op. cit., p. 19.

[456] ibid.

[457] ibid., p. 18.

(iv) *Cross-system and matched withdrawal tariffs*

TRUenergy supports abolishing both these tariffs to further simplify the tariffs in AA3. TRUenergy considers tariffs should be simple, facilitate convenience of payment, be acceptable to all customers and free of controversy.[458]

(v) *Removal of prudent discount*

The EUAA comments that GasNet's proposal to remove prudent discounts is likely to have a significant impact on its members. The ACCC also received a further confidential submission which raised the point that bypass threat is not limited to physical bypass, but could also result through change in production methods using less gas.

The EUAA requested that:

- End users affected by the Prudent Discount issue should be given access to the tariff models, cost models and assumptions that have been used by GasNet to conclude that the Prudent Discount offered in respect of the La Trobe zone is no longer applicable
- In assisting the ACCC/AER to reach a decision on whether the conditions under s. 8.43 of the code have been met, relevant stakeholders should be allowed to make a submission on whether a Prudent Discount should be allowed in respect of any particular service, consequent on receiving the models and information specified above and
- As appropriate, the ACCC/AER should issue formal guidelines for the assessment of Prudent Discount issues so that this issue is determined in a reasonable, fair and transparent way should future prudent discount issues need to be resolved.[459]

With respect to GasNet's proposal to remove its current prudent discount at Pakenham (the ACCC assumes for tariff-V customers), Origin Energy comments that it does not consider market conditions have changed substantially to justify this removal. Particularly with the delay in Yolla coming on stream, the accumulated discounted benefits of the discount to date would not exceed our costs of bypassing the transmission system directly from Pakenham into the Victorian distribution network.[460]

(v) *Corio loop*

TRUenergy comments that GasNet's proposal to allocate 100 per cent of the costs associated with the Corio loop under the system-wide benefits test is consistent with regulatory precedent in previous similar cases.[461]

6.1.5 Assessment

The assessment of GasNet's proposals considers the following:

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458 TRUenergy, op. cit., p. 6.

459 Energy Users Association of Australia, *Submission to the issues paper*, op. cit., p. 3.

460 Origin Energy, op. cit., p. 10.

461 TRUenergy, op. cit., p. 8.

- the proposed changes to the allocation of direct costs to withdrawal and injection tariff zones
- the proposed changes to the allocation of direct costs based on annual and peak usage
- inclusion of the Murray Valley incremental tariff and the Port Campbell injection tariff in the average revenue control
- the allocation of indirect costs, including the allocation of K-factor to tariff zones
- the proposed introduction of a postage stamp tariff for tariff-V users
- the proposal to levy the injection tariff on winter volumes instead of the top ten peak days
- the proposed re-application of prudent discounts for some tariff zones, including the introduction of a discounted export tariff
- the retention of the cross system tariff, the removal of tariff rebates for tariff-V users and the retention of storage refill tariffs and
- proposed introduction of the Geelong withdrawal zone for tariff-D users.

6.1.4.1 Direct cost allocation

GasNet's new tariff model allocates direct costs to final tariff zones (both withdrawal and injection tariff zones) on the basis of average peak and annual ($/TJ-km) direct cost unit rates for all asset groups.

(i) *Cost reflective tariffs*

GasNet submits that the aim of the tariff model should be to create tariffs which are a reasonable reflection of long run costs. GasNet submits that the new tariff model abstracts from the age and condition of individual assets, and the current level of utilisation of those assets, in the short term. It does not reflect the current levels of capital expenditure on specific pipeline segments, but GasNet submits that over the life of the assets, all segments will require augmentation and upgrade at some point in time. Accordingly, the new tariff model is reflective of the costs of individual segments of the PTS over the long term and sends appropriate price signals to end users.[462]

GasNet also submits that its proposed volume-distance methodology ($/TJ-km) retains the main driver of costs, which is distance. GasNet states:

> … the aim of the Tariff model should be to create tariffs which are a reasonable reflection of long-run costs … This is consistent with the Code and with the approach the Commission has adopted

462 GasNet, *Submission*, op. cit., p. 98.

> in assessing whether a proposed tariff structure for a particular Pipeline is appropriate, which is to balance efficiency gains against the administrative simplicity of the various tariff structures.
>
> The proposed volume-distance methodology retains the main driver of costs, which is distance. Again this is consistent Commission's view that distance based tariffs are the most efficient means of charging for gas transportation[463]

The ACCC agrees that distance based tariffs are efficient. However, in considering GasNet's submission, the ACCC notes that while the volume-distance relationship is maintained in allocating direct costs, this is limited to withdrawal tariffs for tariff-D users and injection tariffs. In contrast, withdrawal tariff-V users will be charged the same tariff irrespective of their location and distance from the injection source and tariffs will not reflect the distance that gas is transported. Further, whilst GasNet proposes to retain distance based tariffs for withdrawal tariff-D users, GasNet also proposes to apply an average distance across withdrawal and injection pipelines in calculating the average ($/TJ-km) unit rate to apply to all pipelines.

GasNet submits that in the short term, the new tariff model is likely to lead to lower tariffs than under the current tariff model for some users and higher tariffs for other users. However, GasNet submits that over the longer term it expects this to even out. GasNet comments that any short term adverse consequences will be outweighed by the other benefits, namely increased simplicity, predictability, robustness and price stability, and the positive impact on retail competition.[464]

In its final decision for AA2, the ACCC concluded that the tariff structure and cost allocation methodology proposed by GasNet, as modified by the ACCC's amendments, offered an appropriate balance to the (sometimes competing) requirements of the code.[465] In assessing GasNet's current proposals, whilst a number of approaches may be considered appropriate, the ACCC notes that ss. 8.38 and 8.42 of the code require that tariffs reflect the costs of each service and each user 'to the maximum extent that is commercially and technically reasonable'. This requirement reflects certain aspects of the s. 8.1 objectives, in particular s. 8.1(d) of the code which specifies the reference tariff should not distort investment decisions in pipelines. Other considerations such as simplicity, predictability, robustness and price stability, and the positive impact on retail competition are only applicable indirectly in the way they contribute to the s. 8.1 objectives and are thus of limited relevance to the issue of cost allocation. Accordingly, the ACCC does not consider these other factors in assessing GasNet's cost allocation methodology against the requirements of ss. 8.38 and 8.42 of the code. The ACCC also notes that whilst GasNet and some users have commented that GasNet's proposal will result in administratively simpler tariffs, no evidence has been provided to suggest that tariffs based on GasNet's current more cost-reflective methodology will be less commercially or technically feasible during the AA3 period.

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463 ibid.

464 ibid.

465 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 235.

As part of its analysis regarding whether the tariff methodology proposed for the AA3 period is cost reflective to the maximum extent that is commercially and technically reasonable, the ACCC will consider how the tariff methodology proposed compares to the tariff methodology approved for the AA2 period.

The main difference between GasNet's revised tariff model and the current tariff model is the allocation of direct costs to final tariff charging zones on the basis of average peak and annual ($/TJ-km) unit rates instead of asset group/pipeline segment specific ($/TJ-km) unit rates. This revision results in a reallocation of direct costs in AA3 from the Northern and Western zones of the PTS to the Metro and Eastern zones. For example, users in the Calder zone will be allocated around 30 per cent less direct costs between AA2 and AA3, despite GasNet's proposal to recover a proportion of the proposed capacity related capex in this zone. GasNet acknowledges the immediate reallocation of direct costs between AA2 and AA3 as its states that 'in the short term, the new tariff model is likely to lead to lower tariffs than under the current tariff model for some users and higher tariffs for other users'. The ACCC considers this re-allocation of direct cost between the AA2 and AA3 periods is not consistent with ss. 8.38 and 8.42 of the code, which requires tariffs to the maximum extent that is technically and commercially reasonable, to recover any costs directly attributable to a service (user) as well as a fair and reasonable share of joint costs. It is also not consistent with s. 8.1(d) of the code since the costs of serving users do not reflect the cost of supply.

In considering GasNet's view that in the long run tariffs will even out, the ACCC understands this to mean that tariffs may deviate under the proposed volume-distance approach from efficient levels periodically (such as when users in some zones are paying for investments related to other zones). However, by the time assets have been augmented across all users on the PTS (i.e. over the long-term investment cycle), tariffs set on the basis of this investment cycle, have been efficient from the perspective of an average tariff. Furthermore, GasNet considers that this has the advantage that movements in tariffs across all users will be smoother than under the current cost allocation approach. In particular, GasNet's cost allocation methodology will smooth out any tariff variations resulting from the timing of capital investments.

The ACCC does not consider that all segments of the transmission system will require the same upgrade or augmentation at some point in time. The argument that long-run tariffs will be cost reflective under the current proposal assumes that the increments to capacity will be made in the same proportion across all tariff zones over time (e.g. this assumes that capacity in a 500 mm pipe zone and a 150 mm pipe zone will both increase by the same proportion over time). The ACCC considers this unlikely. Not all zones in Victoria can be expected to grow in demand at the same rate even in the long term. In some regions growth may stagnate, while others face rapid increases in demand. The ACCC notes that GasNet produced no evidence of its claim that all segments will be proportionally augmented over time. Consequently, in the long-run, the ACCC considers the revised tariff model will not produce tariffs which are reflective of the long-run costs of individual segments of the pipeline.

GasNet submits that its proposed cost allocation methodology will promote predictability and stability of tariffs as it removes the impact of the age and condition of individual assets from the allocation of direct costs, and the current level of utilisation of those assets, in the short term.[466]

As noted above, the ACCC considers tariff stability in relation to the timing of investments is of limited relevance to the issue of cost allocation. However, to the extent that GasNet's proposed capex relates to the replacement of assets, GasNet's current tariff model already removes the age and condition of individual assets from the allocation of costs. Further, as the ACCC requires that the majority of GasNet's augmentation capex be included under the economic feasibility test, tariffs should not increase as the incremental revenue from affected users' demand is expected to recover the cost of the investment at the prevailing reference tariff.

(ii) *Promotion of the market for reference services*

TRUenergy comments that the market for reference services will develop and expand in western Victoria under the lower tariffs proposed in AA3, whereas under the current tariff model there would be major tariff increases and this would affect the ability of gas to compete as a viable alternative fuel in western Victoria. TRUenergy concludes that industries reliant on gas as an input located in the area would be impacted, with many losing a competitive advantage. TRUenergy also submits that the lower tariffs are consistent with the state government's policy of promoting the expansion of gas supply in rural areas.[467]

TRUenergy further submits that given the relatively elastic nature of gas demand in rural and regional areas, tariffs produced in AA3 under a zonal gate methodology (i.e. GasNet's current methodology) would lead to a substantial reduction in throughput volumes from assets located in western Victoria, as customers switch to substitute products. TRUenergy states that this would lead to a significant under-recovery of revenue for GasNet from rural assets located in western Victoria.[468]

In considering TRUenergy's view that lower tariffs, will provide an incentives for GasNet to develop and expand the market, the ACCC notes that GasNet already provides for lower tariffs through prudent discounts for some users in the Western zone. GasNet has proposed to retain these prudent discounts for large industrial users. These prudent discounts will provide lower tariffs.

The ACCC has considered the potential for under-recovery of revenue from GasNet's assets in western Victoria but considers that the potential for any under-recovery will depend on TRUenergy's assumption that gas demand in rural and regional areas is elastic. However, TRUenergy has not provided any evidence to support its claim. The ACCC notes that while the elasticity of demand will depend on the price of substitute products such as electricity and bottled LPG, these users are likely to be relatively inelastic in the short run (period of the AA) given that

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466 GasNet, *Submission*, op. cit., p. 98.

467 TRUenergy, op. cit., p. 4.

468 ibid. p. 4.

switching costs are likely to be high. In particular, the costs of connection if relevant, and the cost of new appliances may make switching prohibitive in the short term).

GasNet also proposes a new Geelong zone and submits that this zone will result in lower tariffs for western users as the cost of serving these users is lower than for the Metro zone.[469]

(iii) *Peak and annual usage*

The allocation of costs based on peak and annual flows results in differences between withdrawal tariffs for tariff-V users and tariff-D users within a charging zone. By allocating 65 per cent of direct costs associated with withdrawal pipelines on the basis of peak volume, up from 45 per cent, GasNet is increasing its peak pricing signals for withdrawal tariffs. The allocation of more direct costs on the basis of peak volumes increases the tariff for tariff-V users relative to tariff-D users because tariff-V users tend to have more peaky demand.

In considering GasNet's proposal, it is noted that withdrawal pipelines are becoming more congested (largely driven by tariff-V users).[470] At the time of AA2, the ACCC approved the removal of the peak withdrawal tariffs and levying only anytime withdrawal tariffs. Given this loss of peak signal, and the increase in congestion on withdrawal pipelines, the ACCC considers it appropriate to increase peak signal pricing, and an appropriate way is by increasing a proportion of costs allocated by peak volumes. As such, the ACCC considers GasNet's proposal to allocate 65 per cent of direct costs (up from 45 per cent) on the basis of peak volume for the withdrawal pipelines and 35 per cent on the basis of annual volumes appropriate.

However, GasNet's proposal to allocate 65 per cent of direct costs to injection pipelines on the basis of peak flows (instead of allocating 100 per cent of the direct costs directly to each injection pipeline) results in a flattening of the peak injection tariff, thereby dampening peak pricing signals to injection users. As considered in section 6.1.4.4 of this draft decision, the ACCC does not consider the dampening of peak pricing signals on injection tariffs is appropriate.

Proposed amendment 15

Before the proposed revised access arrangement can be approved, GasNet must amend the revised access arrangement:

- so that the final withdrawal tariffs as set out in cl. 1.3 of schedule 1 of the proposed revised access arrangement to reflect the allocation of costs to withdrawal zones based on the asset group annual and peak direct cost unit rates as these are derived in the modelling for the AA2 period and
- so that final injection tariffs as set out in cl. 1.2 of schedule 1 of the proposed revised access arrangement to reflect the allocation of costs associated with each

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[469] GasNet, *Submission*, op. cit., p. 96.

[470] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 228 and 229.

injection pipeline segment directly to the relevant injection pipeline consistent with the modelling for the AA2 period.

6.1.4.2 Economic feasibility test—cost allocation and inclusion in average revenue yield control

GasNet's proposed cost allocation methodology for AA3 has implications for those assets previously included in the capital base under the economic feasibility test. GasNet's proposed treatment of assets included under the economic feasibility test represents a change from AA2.

In the final decision for AA2 the ACCC considered:

> In the light of it being technically reasonable, the Commission considers that new extensions which enter the RAB under the economic feasibility test should be isolated from the K factor calculation. Further, at the scheduled reviews, *their tariffs should be calculated in such a way that they fully recover the costs associated with the assets (that is, their tariffs should not be derived from the general cost allocation methodology as described in chapter 8 of this Final Decision*). To do otherwise would be contrary to the interests of users and prospective users (section 2.24(f)). *This decision means that these assets will need to recover their costs from their own tariffs*.[471]

In comments on GasNet's proposed postage stamp tariff for V users, AGL notes that a consequence of the proposal for a postage stamp tariff-V is that the Murray Valley incremental transmission tariff, which presently applies to off-takes on the Murray Valley lateral from Chiltern, will now be absorbed into the general tariff for V users. However, AGL further comments that it can accept this consequence as a result of a move towards a uniform withdrawal tariff.[472]

Origin Energy comments that it does not oppose the approach put forward by GasNet, but questions the consistency of postage stamp pricing with the type of pricing signals that might be desirable if there is an intention to reflect the cost of augmentations and extensions to the PTS.[473] Origin Energy further comments that the incremental Murray Valley transmission tariffs were designed to recover the specific costs of that pipeline over more than 20 years as this pipeline has no system-wide benefits.[474] Origin Energy queried whether similar socialisation of costs apply to tariff-V customers on any new augmentation to the PTS pipeline.[475]

Under GasNet's proposal any augmentation capex would be averaged across all users resulting in an increase in tariffs for all users instead of just those users where augmentation is required. As Origin Energy notes, this has implications for future augmentation capex proposed under the economic feasibility test. It also has

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471 ibid., p. 161.

472 AGL, op. cit., p. 2.

473 Origin Energy, op. cit., pp. 3 and 4.

474 ibid., p. 4.

475 ibid.

implications for existing assets previously approved by the ACCC under the economic feasibility test.

(i) *Murray Valley withdrawal pipeline*

For AA2, the ACCC approved the inclusion of the MVP in GasNet's capital base on the basis that it satisfied the economic feasibility test. At the time the ACCC found that the MVP can reasonably be anticipated to generate incremental revenue greater than its initial cost. Accordingly, the ACCC considered it appropriate to include the Murray Valley pipeline in the RAB under s. 8.16(b)(i) of the code.[476]

To recover the MVP costs under the economic feasibility test users of the MVP are currently charged a withdrawal tariff that consists of two components. The first component recovers the cost of withdrawal pipeline usage based on the physical flow path of gas up to Chiltern Valley. The second component, the incremental tariff, is designed to recover the costs (stand alone costs) associated with the $15.6 m MVP.[477]

For AA3, GasNet proposes to include the incremental costs associated with the MVP in the calculation of its average $/TJ-km direct cost unit rates for withdrawal pipelines.[478] Under this proposal the MVP assets are averaged across all users of the PTS. The ACCC has calculated that this results in the MVP assets being allocated 86 per cent less costs than if costs were allocated directly to the pipeline. This is inconsistent with the ACCC's earlier approval that these incremental costs be recovered on a stand-alone basis under the economic feasibility test.

As considered above, the ACCC proposes not to approve GasNet's proposed cost allocation methodology which uses average peak and annual direct cost unit rates for each pipeline segment because it is not consistent with the allocation of costs directly attributable to a service[479] and a user.[480] The ACCC also considers GasNet's proposed cost allocation methodology undermines the integrity of the economic feasibility test, which requires costs to be recovered directly from users of the asset. As stated in the ACCC's final decision for AA2:

> at the scheduled reviews, their tariffs should be calculated in such a way that they fully recover the costs associated with the assets (that is, their tariffs should not be derived from the general cost allocation methodology).[481]

The ACCC therefore requires GasNet to separately calculate an incremental tariff which covers the costs of the MVP.

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[476] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 67.

[477] ibid., p. 233.

[478] Supporting tariff models provided by GasNet to the ACCC.

[479] Code, s. 8.38.

[480] Code, s. 8.42.

[481] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 161.

For AA2, the recovery of the MVP incremental tariff and the Port Campbell injection tariffs (for the Southwest pipeline) were quarantined from the K-factor mechanism and therefore excluded from the average revenue yield price control because they had been included under the economic feasibility test (50 per cent of the Southwest pipeline investment).[482] This was so other users on the system could not possibly subsidise the costs of these assets through general tariff increases.

(ii) *Average revenue yield control*

GasNet proposes a mechanism (similar to the K-factor mechanism), whereby deviations from the allowed average revenue yield may lead to all tariffs increasing to return GasNet its allowed revenue because of tariff mix outcomes. Given this, the concern is that if included in the revenue control mechanism all PTS users could contribute to the recovery of the Murray Valley pipeline or Southwest pipeline assets (50 per cent) which were included under the economic feasibility test requiring costs to be paid for through incremental revenue (volumes). Notably, Origin Energy states that the ‘rolling in’ of incremental tariffs to general rates could represent a ‘socialisation’ of costs.[483]

For AA2, the incremental Murray Valley tariff for the MVP attracted a higher tariff than other parts of the system. The ACCC notes that actual volumes at the MVP have been considerably lower than forecast.[484] Since the incremental Murray Valley tariff was excluded from the price control formula, by implication the ACCC understands that GasNet will not have recovered the costs of this asset over AA2.[485] In contrast, if the tariff had been included in the price control formula, GasNet would have recovered the revenue (or near to) provided total volumes on the system matched forecast because of the operation of the average revenue yield form of price control. That is, all other tariff mix outcomes being constant with forecasts, lower than expected volumes on the MVP would have lead to an under-recovery in terms of the allowed average revenue yield for GasNet as the MVP incremental tariff is higher than the system average tariff. In this circumstance all other tariffs would have been increased in the following year to enable GasNet to recover this shortfall between actual average revenue and allowed average revenue. As a result, users across all tariff zones would have contributed more to the recovery of the costs associated with the MVP based on there being uniform tariff changes.

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482 The ACCC notes the Interconnect tariff was not quarantined during the AA2 period even though 7 per cent of the costs were included under the economic feasibility test. Given the small amounts associated with this 7 per cent portion, the ACCC does not propose to reexclude it for the AA3 period from the revenue control model on the basis it is not considered to be material ($300 000 of direct cost recovery approximately per year).

483 Origin Energy, op. cit., p. 3.

484 This is further considered in chapter 5.4 of this draft decision.

485 Volume forecasts from table 4-4 of the revised AAI approved on 15 December 2004 (2003–06: 1094, 1355, 1597, 1837 TJ) have been compared to actual volumes reported in schedule 2 table 2 to the proposed AAI by GasNet for AA3 (2003–06: 810, 821, 889, 1083 TJ).

For AA3 GasNet proposes to include the MVP incremental tariff within the price control formula (average revenue yield), facilitating the possibility of other users subsidising the recovery of this investment. However, it forecasts volume usage of this pipeline considerably lower than forecasts for AA2 in line with actual lower outcomes for AA2.[486] The ACCC proposes that consistent with the ACCC's previous decision that GasNet must exclude revenues and volumes associated with the incremental Murray Valley tariff from the average revenue yield control model. As noted above, the MVP was included on the basis of the economic feasibility test in s. 8.16(a)(ii)(A) of the code which in practice required for volumes to be charged at the prevailing tariff. The implication of this is that other users do not face increased tariffs because of it. It is inappropriate for other users to have their tariffs affected by the inclusion of the MVP and it is appropriate for revenue recovery for this investment to be completely recovered from volumes charged at the prevailing tariff.[487] The ACCC has proposed the MVP incremental tariff be removed from the price control formula as set out in the chapter 6.3 of this draft decision. This approach still allows GasNet to recover its efficient costs and is consistent with s. 8.1(a) of the code.

The ACCC has also considered whether Port Campbell injection tariffs should continue to be outside the average revenue yield control. The ACCC has noted increased volumes over AA2 and anticipated increases in volumes for AA3 from the Otway Basin.[488] The ACCC considers that the 50 per cent of costs of the Southwest pipeline which entered GasNet's asset base under the economic feasibility test in s. 8.16(a)(ii)(A) of the code now will be recovered directly through volumes at the prevailing tariff through that pipeline. On this basis the ACCC accepts GasNet's proposal to treat these volumes consistently with the general approach in its price control formula.

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486 See GasNet, *Proposed AAI*, table 4-4. Volume forecasts from table 4-4 indicate volumes of approximately 1100 TJ in each year of the AA3 period.

487 In accordance with ss. 8.16(a)(i)(A) and 8.2(c) of the code.

488 See chapter 5.4 of this draft decision.

Proposed amendment 16

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 1.3 of schedule 1 of the revised access arrangement to recover

- 100 per cent of the MVP incremental costs directly from the pipeline and
- retain the two part tariff for users located on the Murray Valley pipeline: one part to recover the costs associated with the Murray Valley pipeline extension (Murray Valley incremental tariff) and the other part to recover the costs (calculated as per GasNet's current cost allocation methodology using specific direct cost unit rates) associated with transportation of gas on the withdrawal pipes to the beginning of the Murray Valley pipeline at Chiltern Valley (Chiltern Valley tariff).

6.1.4.3 Indirect cost allocation

GasNet has previously proposed that the allocation of indirect costs on a postage stamp basis is fair and reasonable as these costs incurred by users equally, irrespective of their physical location or other attributes (such as load factor). This approach was approved by the ACCC for AA1 and again for AA2. The ACCC does not see any reason to change this approach for AA3.

The ACCC notes however that GasNet proposes:

- the Western, Warrnambool and Koroit zones are not allocated any 'rolled out' costs and
- the Murray Valley, Wodonga, North Hume and Interconnect withdrawal zones supplied from the south are not allocated indirect costs.[489]

GasNet advises that the Western zone is not allocated rolled-out costs because it does not benefit from these system-wide benefits as accepted by the ACCC for AA2.[490] For AA3, GasNet proposes to introduce the Warrnambool and Koroit tariff-D withdrawal zones, which are split from the current Western zone. Accordingly, the ACCC considers GasNet's proposal to exclude the rolled out costs from these zones is consistent with the previous treatment of the Western zone.

GasNet proposes that the Wodonga, North Hume and Interconnect withdrawal zones supplied from the south are not allocated indirect costs, since these zones are otherwise too heavily burdened.[491] This is consistent with AA2 in which GasNet did not allocate indirect costs to these Northern zones supplied from the south. At that time, GasNet proposed to allocate some costs which its cost allocation model would normally allocate to the northern zones to other zones. The purpose was to produce tariffs in the northern zones which would not discourage gas transportation, and to

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489 Supporting tariff models provided by GasNet to the ACCC.

490 GasNet, *Email to the AER*, 26 June 2007.

491 ibid.

recover the shortfall from zones in which a marginal increase would not discourage gas transportation.[492]

In its final decision for AA2, the ACCC stated that it must consider 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.[493] For AA3, GasNet, however, has not claimed there is a need to encourage usage in the northern zones. Indeed, GasNet's proposes capital expenditure to address an anticipated increase in demand in the northern zones. As, the ACCC requires GasNet to recalculate these northern zone tariffs based on the current cost allocation methodology, it is likely that these tariffs will increase. Accordingly, the ACCC proposes to accept GasNet's proposal not to allocate indirect costs to the northern zones supplied from the south. GasNet also proposes to include 100 per cent of the Brooklyn Corio loop (Corio loop) costs in the indirect cost allocation to be rolled out on a postage stamp basis (i.e. a general uplift in the withdrawal tariff). The ACCC approved the Corio loop in June 2006 in accordance with s. 8.21 under the system-wide benefits test. The ACCC notes that in its application for the Corio loop, GasNet proposed to recover a portion of the costs from users of the Southwest pipeline by maintaining the Southwest pipeline tariff (Port Campbell injection tariff) at the price path that would prevail in the absence of the loop. Based on its forecasts at the time of its application, GasNet submitted that it expected to recover somewhere between 5 to 10 per cent of the incremental costs of the Corio loop directly from increased flows on the Southwest pipeline at the prevailing tariffs on this pipeline (this proportion will grow over time as the volumes on the Southwest pipeline grow). GasNet submitted the remainder of the costs could be recovered from users through an uplift in the withdrawal tariff.

As noted above, for AA3 GasNet proposes that 100 per cent of the Corio loop costs are recovered through a general uplift in the withdrawal tariff. TRUenergy comments that the costs associated with the Corio loop should be recovered from all tariff-V and tariff-D users and that this cost allocation methodology is consistent with the regulatory precedent.[494]

The ACCC considers the recovery of 100 per cent of the Corio loop costs through a general uplift in the withdrawal tariff is consistent with the recovery of costs under the system-wide benefits test in s. 8.16(a)(ii)(B) of the code and justifies a tariff increase for all users.

(i) *Carry-over K-factor allocation to tariffs*

GasNet's second AA includes a provision for a K-factor adjustment as part of the transmission price control formulae for annual tariff approvals. The K-factor adjustment allows for an increase (decrease) in the maximum average tariff above (below) the price path formula in the year following an under-recovery (over-

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492 GasNet, *Submission*, op. cit., sch. 5; p. 44.

493 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 222.

494 TRUenergy, op. cit., p. 8.

recovery). However, the limitation on increases in individual tariffs of 2 per cent per year restricts the amount of any shortfall that GasNet can recover during the AA2 period.

The K-factor allocation applied to tariffs in AA3 is an allowance for carryover K factor relating to 2006 and 2007 as if schedule 4 of the second AA continued to apply. This is in accordance with the fixed principle as previously approved by the ACCC. The K-factor allowance must be based on actual figures (or estimates where actual figures are not available). In accordance with this fixed principle, GasNet submits a carryover K-factor of $909 768.[495]

For AA3, GasNet proposes to allocate the carryover K-factor on a uniform percentage basis to all withdrawal and injection tariffs with the exception of the following:

- Murray Valley, North Hume, Wodonga and Interconnect withdrawal zonal withdrawal tariffs sourced from South
- Echuca and South West zonal withdrawal tariffs and
- Port Campbell and Pakenham injection tariffs.[496]

GasNet proposes that carryover K-factor be excluded from the northern withdrawal zones supplied from the south so as not to over burden these tariffs.[497] This is consistent with GasNet's proposal to not allocate any indirect costs to these zones. Given that the ACCC requires GasNet to recalculate its northern zone tariffs based on the current cost allocation methodology, this is likely to result in further tariff increases. Accordingly, the ACCC proposes to accept GasNet's proposals not to allocate carryover K-factor to these zones.

GasNet has subsequent to its submission advised that the proposed exclusion of the carryover K-factor from the Echuca and Southwest withdrawal zones and the Pakenham injection tariff is an error, which GasNet intends to correct.[498]

In its final decision for AA2, the ACCC considered that new extensions which enter the capital base under the economic feasibility test should be isolated from the K-factor calculation so that other users on the system could not possibly subsidise the costs of these assets through general tariff increases.[499] The ACCC continues to consider this to be appropriate. Those assets, which have entered the capital base under the economic feasibility test include:

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495 Note this only relates to the 2006 ktb factor and GasNet has stated that it will also include the 2007 KT_a factor at the same time as the agreed timeframe for averaging the risk free rate and estimating inflation.

496 Supporting tariff models provided by GasNet to the ACCC.

497 GasNet, *Email to the AER*, 26 June 2007.

498 ibid.

499 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 161.

- the incremental portion of the MVP and
- a proportion of the Southwest pipeline.

For the AA3 period, the ACCC considers it appropriate that carryover K-factor allocated to:

- the incremental portion of the MVP (incremental Murray Valley withdrawal tariff) and
- the Southwest pipeline (Port Campbell injection tariff).

6.1.4.4 Reference tariff structures

(i) *Postage stamp withdrawal tariff-V*

GasNet proposes to apply a single rate for tariff-V users across the PTS, so that all gas withdrawals from the PTS, which are allocated to tariff-V users will pay the same postage-stamp tariff.

GasNet argues and is supported by AGL that the tariff-V structure can have a significant impact on competition in the gas retail market. In particular, it understands that most retailers amalgamate the PTS transmission tariff zones for the purpose of marketing gas, in order to save administrative costs.[500] As a result, GasNet and AGL submit that a simple, predictable and stable across-the-board flat rate tariff for tariff-V users will reduce administrative costs and encourage new entrants and smaller retailers to enter the market, which will promote gas retail competition. Consequently, GasNet claims that the benefits of a simple tariff structure to retail competition (and the resulting efficiency gains) outweigh the relatively small economic efficiency benefits of a complex zonal tariff structure for tariff-V structures.[501] TRUenergy also comments:

> There is limited value in designing a tariff regime that sends the 'right' pricing signals for gas transmission tariffs, when retailers subsequently amalgamate and smear gas transmission tariffs at a zonal level.[502]

In response to TRUenergy’s view that pricing signals on transmission tariffs are not passed through to end users, the ACCC notes the discretion retailers apply in simplifying transmission tariffs will vary and of itself should not be considered justification for change. The fact that some retailers currently choose to remove the price differentials to customers does not justify more averaged wholesale transmission tariffs. If users of GasNet’s transmission system are not sent the correct price signals at the transmission level, investment decisions in pipeline transportation systems or in upstream and downstream industries may be distorted. This would be inconsistent with s. 8.1(d) of the code. These signals operate on these users whether or not these users also pass the signals onto end users.

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500 GasNet, *Submission*, op. cit., p. 99.

501 ibid.

502 TRUenergy, op. cit., p. 5.

GasNet submits that the transmission charge for tariff-V customers is on average only four to five per cent of the delivered price (which Origin Energy notes could be double the current tariff for some customers) and is a relatively small proportion of the total household budget.[503] GasNet also submits that the transmission tariff is unlikely to have any bearing on the consumption patterns of tariff-V customers, or at most a very minor effect. Accordingly, GasNet claims the economic efficiency benefit of a fully cost reflective tariff structure for tariff-V customers is likely to be small.[504]

In considering GasNet's proposal, the ACCC notes that GasNet has not provided any evidence to support its proposal that the proposed tariff structures will reduce administrative costs and promote retail competition. In considering administrative costs, Origin Energy submits that the ACCC should consider the impact upon users of the PTS of continual change in the structure of underlying tariffs, and the costs to retailers of altering information technology systems and factoring in the uncertainty generated by changes initiated at the beginning of each new AA period.

Origin Energy also comments that:

> With respect to retailers amalgamating tariff zones, while this may be the case, each retailer will make such a judgement depending on their own commercial objectives and systems, and such amalgamation may take place to a greater or lesser extent.[505]

In contrast AGL considers that the prospect that the new tariff methodology will result in simpler administration and management of competitive retail price offers by retailers which should be balanced against the diminution in price reflectivity.[506]

The ACCC in assessing proposed changes to cost allocation in AA2 acknowledged that end-users may not be able to respond to price signals. However, the ACCC also noted that effective price signalling is not the only reason for maintaining tariff relativities between users. In particular, each user's tariff is also meant to reflect the costs associated with that user. In the context of GasNet's proposals for AA3, the application of a postage stamp tariff evens out the costs applying to tariff-V users on any new augmentation to the system. As previously considered, the ACCC considers that given that GasNet has proposed substantial capex over AA3 to address anticipated constraints and these constraints are partly driven by some tariff-V users, these costs should be reflected in the affected tariff zones for AA3. The ACCC notes that the effect of the postage stamp proposal for tariff-V is that a proportion of direct costs would be reallocated from northern zone and western zone users to metro and eastern zone users. As a result, the ACCC considers GasNet's proposed postage stamp rate for tariff-V customers is not consistent with ss. 8.38 and 8.42 of the code.

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503 Origin Energy, op. cit., p. 4.

504 GasNet, *Submission*, op. cit., p. 99.

505 Origin Energy, op. cit., p. 4.

506 AGL, op. cit., p. 2.

One benefit of cost reflective pricing is that it facilitates efficient usage and investment decisions by users. Consequently, it is appropriate for signals to be given to users (retailers) even if they do not pass them on to end users. Users may change their pricing behaviour in the future and pass on cost reflective tariffs. Irrespective of this, cost reflective pricing will give the appropriate basis for users (retailers) to make their own investment decisions.[507] While a single tariff-V would be simpler as GasNet and AGL maintain, the ACCC notes no evidence that complexity is an undue burden and also notes Origin Energy's observation that changing tariff structures also creates additional costs.[508] Accordingly, the ACCC considers that a single postage stamp tariff for tariff-V customers is not consistent with the requirements of ss. 8.38, 8.42 and 8.1(d) of the code.

Proposed amendment 17

Before the proposed revised access arrangement can be approved, GasNet must retain the zonal withdrawal tariffs for tariff-V users and remove the withdrawal tariff-V set out in cl. 1.3(b) of schedule 1 of the proposed revised access arrangement.

(ii) *Injection tariffs structure*

GasNet proposes to charge the injection tariffs as a single flat rate over the peak period (being the winter months of June to September). GasNet suggests that this will improve predictability and transparency, since injection tariffs will be known in advance.[509] GasNet also suggest that the very high level of the current injection tariffs falls disproportionately on those injectors who provide the injections required to balance the PTS during the current ten day period.[510]

The issue of improved predictability and transparency of GasNet's injection tariff has been previously considered as part of the AA2 revisions. At the time of AA2, the ACCC noted that, while cost reflective and efficient pricing signals are of concern to the ACCC, there are also other factors to be taken into consideration. In contrast to withdrawal tariffs, many users regard the current injection tariffs as too complex, confusing and cumbersome. However, the most concern was in relation to the annual 'wash up'. This is an account settling process necessary because most users pay peak charges each month to smooth out their payments. Users considered this process not only to be complex but also to multiply administrative difficulties in allocating costs to individual customers (especially contestable customers). At the time many interested parties advocated the abolition of all peak charges. GasNet, however, did

507 Consistent with s. 8.1(d) of the code.

508 GasNet, *Submission*, op. cit., p. 96.

509 ibid.

510 ibid.

not advocate the removal of all peak charges on the basis that this would not be cost reflective and consistent with the code.[511]

For AA3, AGL and TRUenergy support the move towards a simpler injection tariff which is based on winter volumes rather than on 10 peak days over winter. AGL submits that currently the 10 peak winter days and the magnitude of injections on those days, is not known until October/November each year. Accordingly, a rate that is applied to winter injection volumes, as proposed, will provide greater billing certainty for retailers and customers.[512]

The ACCC notes that under GasNet's proposal injector users with relatively constant injections over the winter period (i.e. high load factors) are likely to experience large increases in charges. In contrast, users with more peaky injections will experience either a decrease in charges or a small increase. As a result, GasNet's proposed change to the injection tariff, advantages these more inefficient users with lower load factor (peakier usage profiles). It is peak usage which puts constraints on the system and contributes to the need for more investment. However, in a competitive market, these constraints would be reflected in the cost of providing the service. As such GasNet's proposed change to its injection tariff is less consistent with ss. 8.1(b) and 8.1(e) of the code.

At the time of the AA2 decision, the ACCC considered at some length the issue of introducing a peak injection tariff for the whole winter period. This issue was considered in response to submissions from stakeholders suggesting that injection charge be based on peak winter volumes, instead of the 10 peak days. The ACCC concluded that while this would reduce complexity faced by users, it would also reduce the effectiveness of the peak signalling.[513]

Indeed, at the time of AA2, the ACCC considered GasNet's 10 day peak charge to be one of the advantages of its tariff structure. The 10 peak days not being known in advance gives users the incentive to modify their behaviour over the whole winter period in which the peak charges may arise. The ACCC concluded that 10 day peak charge requires users to pay in proportion to their contribution to the maximum capacity demanded from the system. This pricing structure is the feature which provides incentives for best utilisation of pipeline infrastructure. To the extent that users avoid peak times, the pressure on system capacity (and enhancements) is diminished and efficient use of the assets is encouraged.

In its AA2 decision, the ACCC considered that evaluation of GasNet's proposed change to its injection tariff depends on whether there should be peak pricing signals and that this in turn leads to two associated questions:

- Is there (or is there likely to be) constraint on the system?

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511 ACCC, *Draft Decision: GasNet Australia access arrangement revisions for the Principal Transmission System*, 14 August 2002, p. 133.

512 AGL, op. cit., pp. 2 and 3.

513 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 229.

- Will users respond to the possible price signals available?[514]

The ACCC has considered these two questions for AA3 and has found no evidence to suggest that there is currently or anticipated constraints on the injection pipelines (except for the SWP, where the Corio loop will remove a known bottleneck in the system). The ACCC considers this suggests that the current peak pricing structure is working. That is users are responding to the peak pricing signals. Further, the ACCC considered in its AA2 decision that peak signals are appropriate before congestion occurs, as 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 adding to the capacity constraint.[515]

The ACCC considers that the AA2 decision of maintaining peak price signals on injection pipelines should be retained for AA3. For the above reasons, and the concern that more efficient users will be disadvantaged under GasNet's proposed winter peak period for injection tariffs, the ACCC supports maintaining the current injection tariff peak period of the ten peak days.

GasNet also submits that a major problem with calculating injection tariffs on ten peak days is that gas suppliers cannot know the gas injection tariff in advance. GasNet submits that this is particularly problematic for suppliers who inject specifically to meet those peaks on the days of the year when the PTS requires peak balancing. The ACCC considers users have discretion whether or not to include the injection tariff in their market bids and of itself this should not be justification to move from a ten peak day charge. In particular, the ACCC considers the maintenance of peak price signals on the injection pipelines as a tool to manage system constraint is more appropriate. The EUCV: noted that GasNet's proposal:

> … is a trend away from the AEMC review for electricity where the AEMC considers that a more cost reflective tariffs will result from moving from a long term basis to one representing the highest demands experienced. The logic of the AEMC revolves around the principle that as investment is related to the highest demands on the system (i.e. the system is built to manage the highest daily – even hourly- gas usage) then the most cost reflective tariffs must be set based on peak usage, and not on average usage. A move to average usage results in less cost reflectivity, and increases greater cross subsidisation from high load factor users to low load factor users.[516]

The ACCC agrees that the move away from the top ten peak days will advantage low load factor users and will not provide incentives for users to minimise usage over the peak period.

In conclusion the ACCC considers that maintaining a peak injection tariff will provide tariffs that are efficient in level and structure and not distort investment decisions respectively in accordance with ss. 8.1(e) and 8.1(d) of the code. Consequently the ACCC proposes not to approve GasNet's proposal to change its peak injection charge.

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514 id., *Draft Decision: GasNet Australia 2002–07*, op. cit., p. 131.

515 id., *Final Decision: GasNet Australia 2002–07*, op. cit., pp. 216 and 217.

516 Energy Users Coalition of Victoria, op. cit., p. 19.

Proposed amendment 18

Before the proposed revised access arrangement can be approved, GasNet must amend the proposed revised access arrangement to maintain the current injection tariff structure, where the peak period applies to the top 10 peak days during the winter period, instead of applying the charge over the whole winter period as proposed in cl. 1.2 of schedule 1 of the proposed revised access arrangement.

6.1.4.5 Prudent discounts

Section 8.43 of the code provides that prudent discounts may be offered at the commencement of a new AA period in a situation where a user can obtain a lower cost service from a bypass pipeline than from the reference tariff. In these circumstances it may be appropriate to offer a discount to the user in order to retain their (albeit reduced) contribution to revenue on the regulated pipeline. A discount is deemed to be prudent if, in the situation where the at-risk user is retained at a discounted tariff, the reference tariff calculated for all other users is lower than the reference tariff calculated without the at-risk users contribution.

In the final decision for AA2, the ACCC accepted the prudent discounts proposed for AA2.[517] The prudent discounts were approved by the ACCC to expire at the end of the AA2 period (as specified in those decisions) and would need to be proposed by GasNet for AA3 to be considered by the ACCC. For the AA3 period, GasNet proposes to apply prudent discounts to tariff-D users at Pakenham and the two new western zones, Warrnambool and Koroit. GasNet has also not sought to reapply some prudent discounts for the AA3 period.

(i) *Pakenham*

For the AA2 period, GasNet argued that a bypass risk existed between the Dandenong off-take of the PTS and Pakenham, where gas is injected into the PTS from the BassGas production facility. GasNet considered that this facility is anticipated to inject approximately 20 PJ per annum into the PTS at a high load factor. GasNet concluded that in the event that bypass was constructed, this gas could be used to displace gas supply from Longford through the PTS. For AA3, GasNet has re-estimated the cost of bypass.[518]

The ACCC has considered GasNet's proposal to apply prudent discounts to tariff-D users at Pakenham. GasNet proposes a higher tariff than in AA2; but considers this tariff to be less than the cost of a bypass tariff.[519] The ACCC has audited the

517 ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 224.

518 GasNet, *Submission*, op. cit., p. 104.

519 For Pakenham, GasNet proposes a bypass tariff of \$0.164/GJ in \$2008. GasNet proposes to implement the Pakenham bypass tariff as an injection tariff at Pakenham and a discounted withdrawal tariff in the Metro southeast zone. The injection tariff is determined as a proportion of the Longford injection tariff, pro rated by distance from Pakenham to Dandenong. The injection tariff is \$0.0404/GJ for winter volumes, where GasNet assumed the winter charge is 35 per cent of the annual volume for Pakenham. Hence the equivalent annual charge is \$0.0141/GJ (35 per cent of \$0.0404/GJ). GasNet calculates the prudent discount so that the sum

methodology and assumptions used by GasNet to calculate the bypass tariff and consider these to be reasonable.

In particular, GasNet assumes a capital cost of $55 000/in/km of pipeline, fixed operating costs of $0.17 m and operating costs of $1.8/metre. To calculate the cost of bypass GasNet assumes a 20 year life for the bypass asset. The ACCC notes that this assumed life is significantly shorter than the standard life of a pipeline, resulting in a higher bypass tariff and therefore a lower prudent discount than if a standard life was adopted.[520]

While the ACCC agrees with the methodology and the cost inputs, the ACCC notes that given the requirement to recalculate the injection tariff based on the top 10 peak days, the prudent discount for Pakenham may change. Accordingly, the proposed prudent discount for tariff-D users at Pakenham is not appropriate and the AA should be amended. However, the ACCC is open to assessing a proposed prudent discount based on the top ten peak days.

Proposed amendment 19

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 1.3(g) of schedule 1 of the proposed revised access arrangement to remove the prudent discount for tariff-D users at Pakenham.

(ii) *Warrnambool and Koroit*

GasNet submits that a bypass risk in the Western zone arises from the SEA Gas pipeline which parallels the PTS between the towns of Warrnambool and Koroit. To discourage bypass, GasNet proposes to continue to apply two discounted withdrawal tariffs for tariff-D users at Warrnambool and Koroit, but discontinue those for tariff-V users since a uniform withdrawal tariff for these users is proposed for the PTS. GasNet calculates the bypass tariffs for tariff-D users (in $2006) to be $0.078/GJ for Warrnambool and $0.162/GJ for Koroit.[521]

GasNet has determined these bypass tariffs using the following steps:

- calculate the cost of bypassing the PTS using the SEA Gas pipeline, consisting of an assumed tariff and the annualised cost of heating and regulator equipment needed to facilitate bypass
- calculate VENCorp charges on the pipeline segments and

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of the injection tariff and Metro south east withdrawal tariff is equal to the bypass tariff. Based on the injection tariff, GasNet calculates the withdrawal tariff for the Metro south east zone matched to Pakenham to be $0.1503/GJ in order to match the bypass tariff.

520 Supporting tariff models provided by GasNet to the ACCC.

521 GasNet, *Submission*, op. cit., pp. 103 and 104.

- calculate the bypass tariff for each zone as 90 per cent (i.e. a 10 per cent discount) of the bypass cost/GJ, less the VENCorp charge.[522]

The method used by GasNet to calculate bypass tariffs is the same as that underlying the tariffs approved by the ACCC in 2002. ACCC has reviewed GasNet's calculations and accepts the proposed tariffs for tariff-D users for the AA3 period.

GasNet notes that the application of the postage stamp rate for tariff-V users at Koroit does not create a bypass concern, although it may for tariff-V users at Warrnambool. The ACCC does not accept the proposed postage stamp tariff for tariff-V customers. Accordingly, GasNet may need to reconsider its approach to the tariffs and bypass risk associated with tariff-V customers in the Warrnambool and Koroit zones.

(iii) *Latrobe/Wodonga*

The ACCC received no submissions regarding the removal of prudent discounts to Wodonga withdrawal zone tariff-D and V users, but submissions were received in relation to the removal of the prudent discount for withdrawal tariff-D users in the Latrobe zone. Australian Paper submitted that it will experience an increase in total gas transmission charges for its Maryvale Mill of 160 per cent in 2008.[523] The EUAA commented that end users affected by the prudent discount should be given access to the tariff models, cost models and assumptions that have been used by GasNet to conclude that the prudent discount offered in respect of the Latrobe zone tariff is no longer applicable.[524]

The ACCC has considered submissions from Australian Paper and the EUAA regarding the removal of the prudent discount and the EUAA's request for access to the tariff models that have been used by GasNet to determine whether to offer prudent discounts. However, in the case of GasNet, if it does not re-apply for a prudent discount at the end of AA2, the regulator under s. 8.43 of the code cannot by itself determine that the current prudent discount will be reinstated. This means that GasNet is not required to justify why it has not re-applied for a particular prudent discount, as any prudent discounts in place will simply expire at the end of the second AA period. This is consistent with the ACCC's decision for AA2 to accept the prudent discounts to apply only for the AA2 period. Accordingly, the EUAA's request for GasNet's tariff models regarding the removal of its prudent discount is not relevant. Nevertheless, in general, the ACCC does not believe that provision to interested parties of detailed tariff models is required by the code. The code requires interested parties to be able to understand the derivation of the elements in the proposed AA not necessarily to be able to duplicate the tariff calculations. This is consistent with the ACCC's draft decision for AA1, which in response to submissions the ACCC considered whether users and prospective users should be given sufficient financial data to allow them to replicate the service provider's tariff

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[522] Supporting tariff models provided by GasNet to the ACCC.

[523] Australian Paper, op. cit., pp. 1 and 2.

[524] Energy Users Coalition of Victoria, op. cit., p. 3.

calculation. At the time the ACCC considered the code does not require the service provider to provide such information to enable users and prospective users to replicate the service provider's tariff calculations.

(iv) *Export tariff*

For AA3, GasNet is forecasting exports of 5 PJ/year through the Interconnect. This volume utilises the majority of the available AMDQ capacity of 17 TJ/day through the Interconnect pipeline.[525] GasNet's proposed investment to provide an expansion of firm winter capacity of 17 TJ/day or 6.2 PJ per year requires additional capital expenditure as proposed by GasNet for AA3. GasNet proposes the most likely customers for the export volumes are the proposed Uranquinty power station, near Wagga Wagga, and other end users in country NSW. GasNet comments however, there is no assurance that these volumes will continue to flow, as the customers have the option of gas supply from Moomba via the MSP, or from Bass Strait via the EGP and gas swaps.[526]

GasNet proposes that in view of the highly competitive nature of the market, the Culcairn export tariff should be discounted to a level which still exceeds the incremental cost of supply.[527] GasNet proposes an export tariff of $0.50/GJ, which it considers exceeds the long run incremental costs and comments that it is therefore a prudent discount.[528] To calculate the incremental cost of its proposed export tariff, GasNet first calculates base case anticipated capital costs of transmission in the northern zones without any exports and compares this to the anticipated costs under an export scenario. Based on the incremental export cost and the forecast 5 PJ per annum of export gas, GasNet then derives a tariff to recover the incremental cost of exports over a 30 year period of $0.498/GJ.

GasNet comments that to the extent that the tariff exceeds the incremental cost, the existing Victorian user can only be better off. However, if a higher tariff (based on

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525 GasNet, *Submission*, op. cit., p. 102.

526 ibid., pp. 102 and 103.

527 ibid., p. 103.

528 Under its no export scenario GasNet forecasts it will require expenditure for:

- two new Saturn compressors at Euroa in 2009 and
- to redevelop Wollert with two Centaurs compressors in 2009

Under its export scenario, GasNet forecasts it will require expenditure for:

- two new Saturn compressors at Euroa in 2008 (one year earlier than under the base case)
- to redevelop the Wollert compressor station with 2 centaurs in 2008 as per the base case and
- additional pipeline looping from Wollert to LV3 loop in 2008 and to complete the loop in 2016 to augment capacity.

Based on forecast exports of 5 PJ/annum and compression costs of $0.08/GJ, GasNet estimates additional operating costs of $0.4 m per annum. GasNet derives NPV estimates for the no export and export scenarios and calculates the difference between these scenarios as the incremental cost of exports.

the new tariff model) is applied to exports, there is risk that the flows may not eventuate, which would therefore provide no immediate or future benefits to Victorian users.[529]

In assessing GasNet's proposed discounted export tariff the ACCC considers it appropriate to address:

- whether a discount is appropriate (i.e. competition risk - if a discount is not offered flows may not eventuate) and
- whether the discount is prudent (i.e. if, in the situation where the at-risk user is retained at a discounted tariff, the reference tariff calculated for all other users is lower than the reference tariff calculated without the at-risk users contribution).

At this stage the ACCC is unable to fully assess whether a discount is justified for the export tariff. The ACCC notes that GasNet has not provided evidence of effective competition at the Interconnect or justification of its proposed export tariff against competitive 'bypass' tariffs. GasNet has only stated that if a higher tariff is applied to exports, there is risk that the flows may not eventuate.[530]

In addition, the ACCC considers GasNet's proposed calculation of its discounted export tariff does not benefit existing users as it recovers only the incremental cost required to facilitate the forecast exports and not the share of common costs. Accordingly, the ACCC does not consider this proposal to satisfy s. 8.43(b) of the code.

As the ACCC considers that both pipeline looping and compressor capex will accommodate the requirements for meeting anticipated pressure breaches at Shepparton and concurrently allow 17 TJ/day of firm capacity through the Interconnect, GasNet's calculation of the export tariff should reflect a proportion of these costs. Accordingly, the ACCC requires GasNet to recalculate its export tariff to reflect a proportion of these costs.

GasNet should also provide further evidence to justify a discount. This should include a comparison of GasNet's proposed export tariff against a bypass tariff.

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529 GasNet, *Submission*, op. cit., p. 103.

530 ibid.

Proposed amendment 20

Before the proposed revised access arrangement can be approved, GasNet must amend the proposed revised access arrangement to calculate its export tariff (as proposed in section 11.6.2 of the revised access arrangement submission) based on the tariff model used in the second access arrangement.

6.1.4.6 Cross-system withdrawal tariff

For AA2, the ACCC approved GasNet's proposal to introduce a cross-system tariff.[531] The cross-system tariff is an additional levy for carriage of gas through the Metro zone, for withdrawals off the injection pipeline which are linked to injections at an unrelated injection point. This levy is calculated as the Metro zone tariff discounted for the indirect cost allocations (which are already recovered from the withdrawal zones). The cross system tariff does not apply to the northern zones as the costs of transmission through the metro zone are included in the northern withdrawal tariffs.

TRUenergy suggests that the cross system tariff should be abolished to simplify tariffs in AA3.[532]

In response to TRUenergy's comments, the ACCC notes that the cross system tariff recognises the additional cost of carriage across the system for where a zone is not supplied from its nearest injection point. Accordingly, the ACCC considers it appropriate for GasNet to apply an additional levy recognising the additional cost of transportation. This is consistent with ss. 8.38 and 8.42 of the code. The ACCC notes that as it proposes to not approve GasNet's proposed cost allocation methodology, the level of the cross system tariff is likely to change.

6.1.4.7 Matched rebates

GasNet proposes to continue its matched rebates for tariff-D users for AA3. However, GasNet proposes removing matched rebates for tariff-V users related to withdrawals from the North Hume, Murray Valley, Interconnect and Wodonga zones for gas injected at Culcairn as it also proposes a postage stamp tariff for V users. TRUenergy supports abolishing matched rebates in order to simplify tariffs.[533] The ACCC notes that as it has rejected the postage stamp approach to tariff-V tariffs, accordingly GasNet's reasons for removing the matched rebates no longer apply. The ACCC considers that matched rebates continue to be consistent with the code requirements that tariffs be cost reflective to the extent that this is commercially and technically reasonable. Accordingly, the ACCC considers that matched rebates should be maintained for tariff-V users for AA3 as this is consistent with ss. 8.38 and 8.42 of the code.

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[531] ACCC, *Final Decision: GasNet Australia 2002–07*, op. cit., p. 231.

[532] TRUenergy, op. cit., p. 6.

[533] ibid.

Proposed amendment 21

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 1.3(b) of schedule 1 of the proposed revised access arrangement to include matched rebates for tariff-V users in the North Hume, Murray Valley, Interconnect and Wodonga withdrawal zones for gas injected at Culcairn.

6.1.4.8 Storage refill tariffs

GasNet proposes to continue to charge a gas storage refill tariff.[534] For the underground storage at Port Campbell, GasNet proposes a tariff of $0.20/GJ and for refill of the LNG Storage Facility a tariff of $0.15/GJ. These tariffs represent increases of around 66 and 36 per cent from the AA2 period, from $0.12/GJ and $0.11/GJ respectively.

GasNet indicates that these tariffs are intended to reflect the marginal cost of delivering these services, namely the amount of fuel used by the compressor units to transport each GJ of gas from these facilities. Related costs, namely the routine maintenance of the compressors, is included as part of GasNet's overall opex allowance. The marginal cost of providing these services is difficult to ascertain as it depends on gas flows elsewhere in the network that affect the utilisation and efficiency of compressors. GasNet estimates that the cost/GJ withdrawn ranges from $0.10 to $0.55 throughout the year, with higher costs observed in winter months where the efficiency of compressors is significantly lower. GasNet notes that its current refill tariffs were based on the assumption that these facilities would be used in summer although it has observed higher demand in the winter months over the last three years. GasNet also points out that it incurred other losses in 2004 where the Iona compressor facility was used to ship gas out of the PTS on which refill tariffs were not (and are still not) applicable.[535]

The ACCC considers that the information provided by GasNet justifies an increase in the tariff. While there appears to be some judgement involved in deriving the estimated costs, this is balanced against the under recovery of fuel gas costs incurred by GasNet over the last several years. Accordingly, the ACCC considers that GasNet's proposed refill tariffs will provide sufficient opportunity to recover the costs of this service in accordance with s. 8.1(a) of the code.

6.1.4.9 Introduction of the Geelong withdrawal zone

GasNet proposes to separate Geelong from the Metro zone. GasNet proposes that with the increased gas volumes flowing on the SWP, Geelong will have a bypass opportunity to obtain supply direct from the SWP, thereby avoiding the Metro zone tariff.[536]

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[534] GasNet, *Submission*, op. cit., p. 102.

[535] id., *Email to the AER*, 14 September 2007.

[536] id., *Submission*, op. cit., p. 94.

The allocation of direct costs to each of the off-takes in the Geelong zone assumes that all the gas supplied to these off-takes is injected at Port Campbell. This is a more defined zone than the current Metro zone which includes off-takes supplied from Port Campbell, Pakenham and Longford and accordingly for which the average cost of transportation is higher.

The ACCC considers GasNet's proposal to introduce a new Geelong withdrawal zone reasonable consistent with s. 8.42 of the code. However, given the ACCC's requirement that GasNet calculate specific direct cost unit rates, the ACCC considers it more appropriate for GasNet to allocate costs to the Geelong withdrawal zone based on the specific direct cost unit rates. Further given the ACCC's requirement that GasNet retain zonal tariffs for tariff-V users, the ACCC considers it appropriate GasNet calculates a Geelong zonal withdrawal tariff for tariff-V users.

Proposed amendment 22

Before the proposed revised access arrangement can be approved, GasNet must:

- allocate direct costs to the Geelong withdrawal zone based on specific direct cost unit rates and
- calculate a Geelong zonal withdrawal tariff for tariff-V users.

6.2 Reference tariff path

6.2.1 Code requirements

Section 8.3 of the code provides discretion to service providers in how the reference tariffs may be varied during an AA period. This allows the service provider to select from four different approaches, or to choose any combination or variation of these approaches. These four approaches include:

- the cost of service approach—where tariffs are adjusted throughout the AA period to account for actual outcomes (such as sales volumes and actual costs) to ensure that the actual costs of the services are recovered
- the price path approach—where tariffs are determined prior to the commencement of the AA period and follow a path which is not adjusted to take account of subsequent events until the start of the next AA period
- the reference tariff control formula approach—where tariffs may vary over the AA period in accordance with a specified formula or process and
- the trigger event adjustment approach—where a reference tariff may vary within the AA period following the occurrence of a specified event.

Section 8.3A of the code states that reference tariffs may vary within an AA period only through the implementation of the approved reference tariff variation method as provided for in ss. 8.3B–8.3H of the code.

6.2.2 Current access arrangement provisions

GasNet's current approach for varying reference tariffs is best described as a combination of both a price path and a cost of service approach.[537]

Annual variations to GasNet's tariffs are in accordance with an average revenue yield form of price control. The average revenue yield allows GasNet to earn a maximum average yield (rate) per unit of actual gas volume delivered each year of the AA period. This allowed maximum average rate is based upon a forecast average rate for the year, which was pre-determined at the commencement of the AA2 period and a CPI based price path of CPI–PPT. The forecast average rate for each year of the AA2 period is set out in schedule 4 of the second AA. PPT is the price path factor and is set at 5 per cent.[538]

Under the second AA, provision is made to alter the pre-determined average rate within the AA period. This is done firstly by the K-factor, which ensures that GasNet has the opportunity to adjust for any over or under-recoveries against the previous year's allowed maximum average rate. Secondly, a pass-through mechanism applies

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537 The ACCC noted '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': ACCC, *Final Decision: GasNe Australia 2002–07*, op. cit., p. 239.

538 GasNet, *Proposed AA*, op. cit., p. 45.

to a number of costs, such as insurance costs, that may alter within the AA period. This provision to allow for K-factor adjustments and pass-throughs is consistent with a combination of a price-path and cost of service approach.

In summary, the allowed maximum average rate for each year is the result of the forecast average rate (ATT) as per schedule 4.4 of GasNet's AA, the CPI–PPT price path and any K-factor adjustments and pass-throughs.

The allowed maximum average rate operates as an overriding constraint on GasNet's individual annual tariff adjustments. In effect the weighted average of GasNet's proposed reference tariffs for the year, must be less than or equal to the allowed maximum average rate for that year.

In addition to this overriding control on tariffs, two further constraints are applied to each individual reference tariff. These are:

- a CPI–X constraint, where X is set at either 3 per cent or 0 per cent on individual tariffs as per Schedule 1 of GasNet's AA and
- a re-balancing control of 1 + Y, where Y is set at 2 per cent.

This means that under GasNet's second AA reference tariffs may vary by CPI–X+Y as long as the overriding allowed maximum average tariff constraint is not breached. On an annual basis, in order to comply with the overriding allowed maximum average tariff constraint, some reference tariffs may not be able to increase by the full extent allowed by their individual constraint of CPI–X+Y.

6.2.3 Proposal

For AA3, GasNet proposes to apply a combination of a reference tariff control formula approach and trigger event approach to varying its reference tariffs.[539]

Under this approach, GasNet's initial set of reference tariffs may vary over AA3 in accordance with the revenue control formula as considered in chapter 6.3 of this draft decision.

Essentially, the proposed revenue control allows GasNet to earn revenue (adjusted target revenue) over the five year period based on:

- a pre-determined average yield/GJ for each year of the period (based on target revenue and target volumes) and
- a total volume (the adjusted achieved volume) which is a volume determined by removing the impact of cold weather from actual outcomes, but bounded within 5.5 per cent above or below the pre-determined (weather normalised) target volume.

The target revenue is adjusted each year of the period (adjusted target revenue) to reflect the adjusted achieved volume.

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[539] id., *Submission*, op. cit., p. 13.

In addition to the revenue control, GasNet proposes to apply a (CPI–X) constraint of either zero or –2.8 per cent for each tariff (as per schedule 1 of GasNet proposed AA) and a re-balancing control of (1+Y), where Y is set at 2 per cent. Accordingly, under GasNet's proposal no component of the transmission tariffs can be increased by more than (CPI–X)(1+Y). GasNet proposes zero X factors apply to the following tariffs:

- withdrawal tariff-D at Warrnambool, Koroit and Culcairn
- system export tariff at SEA Gas pipeline
- withdrawal for storage at LNG and WUGS and
- matched withdrawal tariff-D at Metro southeast.

GasNet's proposed revenue control has provision to alter the adjusted target revenue in order to accommodate some specified events within the access arrangement period. This is done through a pass-through mechanism which is consistent with a trigger event approach.

For AA3, GasNet proposes an average tariff of $0.40/GJ in 2008. This is in an increase of approximately 36 per cent when compared to the 2007 average of $0.29/GJ.

6.2.4 Submissions

Origin Energy queried whether GasNet's proposed increase in its real average tariff in 2008 meets the objectives of the tariff path established for AA2 to minimise price shock for AA3. Origin Energy further seeks an explanation as to why the previous forecasts and proposed treatment of the revenue path were so inadequate, so that price shocks in the future can be avoided.[540]

6.2.5 Assessment

The increase in GasNet's proposed average tariff for 2008 compared to the 2007 actual average tariff is the result of:

- The proposed increase in capex and opex for AA3.
- The proposed lower forecast volumes over the AA3 period compared to the AA2 period.
- An actual average tariff in 2007, which is lower than the initial ACCC approved forecast average tariff for 2007. This is the result of initial over-recoveries against the allowed maximum weighted average tariff during the early years of AA2, which lead to subsequent reductions (K-factor adjustments) to the allowed maximum average tariff in the following years.

Under an average revenue yield control an over-recovery against the allowed weighted average tariff will occur if more volume flows to a high priced zone and

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[540] Origin Energy, op. cit., p. 5.

less to a lower priced zone than forecast. Likewise an under-recovery will occur if more gas flows to a lower priced zone than forecast. Any over or under recovery against the allowed weighted average tariff for a particular year, must be paid back or recovered through adjustments to the subsequent years' tariffs (through the K-factor adjustment) to refund the excess recovery, or to recover the shortfall, from customers respectively.[541]

During AA2, GasNet over-recovered against the allowed weighted average tariff in 2004, 2005 and 2006 and was required to reduce tariffs each following year to pay back this over-recovery. The major contributing factor to this over-recovery was the delay in the Yolla Project, which did not come into production until June 2006. This meant that little or no gas was eligible for the discounted withdrawal in the Metro south east zone as had been originally expected from mid 2004. As a result of the over-recovery during AA2, GasNet's allowed average tariff for 2007 is $0.2947/GJ. The ACCC estimates that if no K-factor adjustments had been required during AA2 and the forecast price path had been followed, the average tariff in 2007 would be $0.3379/GJ. The difference between GasNet's allowed average tariff for 2007 and the initial ACCC approved forecast average tariff for 2007 is about 15 per cent.

The ACCC regards the following elements as relevant in assessing GasNet's proposed tariff path:

- the initial change in tariffs (the change between 2007 and 2008)
- the movement of tariffs within the period (as indicated by the X factors – 2.8 per cent and 0 per cent) and
- the change in tariffs at the end of the period moving into the subsequent period (for GasNet this is the change between 2012 and 2013).

Given the absence of public submissions to the contrary, the ACCC assumes users are comfortable with the proposed real annual increase of 2.8 per cent for the majority of GasNet's tariffs during AA3, as a flat real price path over the period would require a higher step change in tariffs between 2007 and 2008. The ACCC notes this is a significant change from the AA2 period under which real decreases of 3 per cent applied to the majority of GasNet's tariffs.

As a result of the ACCC's proposed amendments to GasNet's revenue requirement and volumes in this draft decision the difference between the actual average tariff for 2007 and 2008 has been reduced. The ACCC estimates this difference to be approximately 16 per cent, if GasNet maintains its proposed real increase of 2.8 per cent (X = –2.8) for the majority of its tariffs, or 22.5 per cent if a flat real tariff path (X = 0) is adopted.

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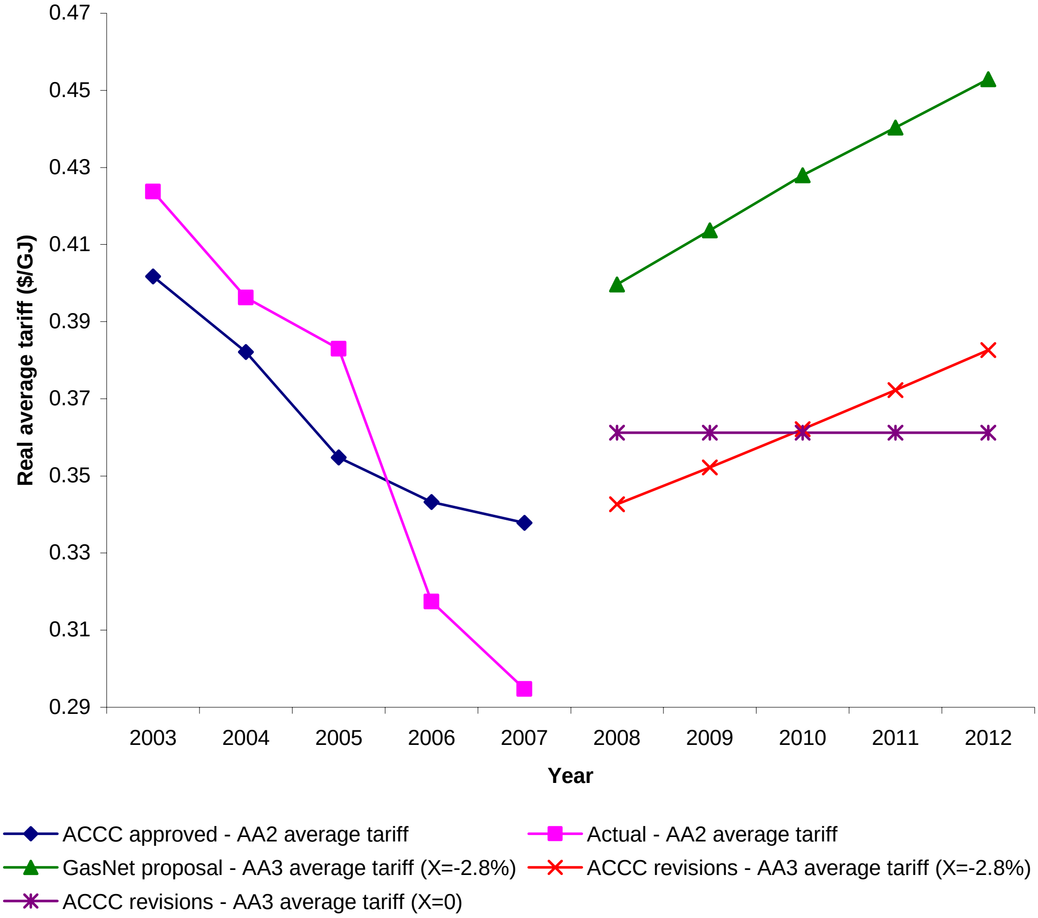
[541] The average revenue yield control, however, does not protect against differences in total volume. Meaning that if less (more) volume flows than forecast less (more) revenue will be achieved than forecast. This means that under an average revenue yield control it is possible to under recover on total revenue (total volume being less than forecast), but to over recover on the weighted average tariff (proportionally more volume flowing through high priced zones than low priced zones). In this situation tariffs for the following year would be reduced by the K-factor to pay back the over recovery on the allowed weighted average tariff.

The ACCC notes, however that the AA3 average tariff as estimated by the ACCC will increase if GasNet is able to demonstrate that the portion of the Northern zone capex proposal necessary to address the anticipated breach of the minimum system pressure requirements and the Warragul loop proposal are reasonable expected to satisfy the requirements of the economic feasibility test in s. 8.16(a)(ii)(A) of the code.[542] Similarly, this AA3 average tariff will also increase if GasNet is able to further demonstrate how the velocity concerns relating to the Pakenham capex proposal is reasonable expected to satisfy the requirements of the system integrity test in s. 8.16(a)(ii)(C) of the code. In the event that GasNet is able to demonstrate capex for all of the Northern zone, the Warragul loop and the Pakenham loop is reasonably expected to satisfy the appropriate requirements of the code, the ACCC estimates the difference between the actual average tariff in 2007 and the 2008 average tariff will increase from 16 per cent to 21 per cent (assuming an X-factor of –2.8 per cent).

Figure 6.2.1 sets out indicative estimates of the tariff movement for the AA3 period based on the ACCC's revisions, adopting X factors of –2.8 per cent and of 0 per cent. In order to compare the estimated average tariff movement between the AA2 and AA3 periods, this figure also shows the movement in GasNet's actual average tariff over AA2 and the ACCC approved initial forecast average tariff movement as made at the commencement of AA2. This initial ACCC approved forecast average tariff shows the expected movement in tariffs during the AA2 period in the absence of volume forecast error (K-factor adjustments) if the price path had been followed. That is, in 2003 users would have expected an average tariff of around \$0.3379/GJ for 2007 and not the actual average tariff of \$0.2947/GJ.

[542] As considered in chapter 3.3 of this draft decision.

Figure 6.2.1: Tariff path



The ACCC notes that whilst the step increase between the AA2 and AA3 periods remains significant despite the revised revenue requirement, an X of –2.8 per cent will result in an average tariff in 2008 of $0.3426 which is only 1.4 per cent greater than the initial ACCC approved forecast price path average tariff for 2007 of $0.3379 (if no K-factor adjustments for the over-recovery experienced earlier in the period were necessary). As noted above, the actual allowed average tariff for 2007 of $0.2947/GJ is the result of users on average paying more than the maximum allowed tariff in the earlier years of AA2. The lower actual average tariff in 2007 reflects the balancing out of the higher average payments made by users earlier in the AA2 period. Accordingly, the ACCC does not consider the 2007 average tariff level indicative of the long term level.

The ACCC has also considered an X factor of zero for the AA3 period. Based on the revised revenue requirement this would imply an average tariff of $0.3612 in 2008, which is a greater step jump of 22.5 per cent between the actual average tariff in 2007. However, if compared to the initial ACCC approved forecast average tariff for 2007, this step jump would be 7 per cent.

An X factor of zero may be appropriate if the average tariff in 2013 is likely to be around $0.3612/GJ (the forecast average tariff at the end of the AA3 period). If, however the average tariff in 2013 is likely to be above $0.3826/GJ an X of –2.8 per cent may be more appropriate as this will more effectively manage the transition between AA2 and AA3 period as well as between AA3 and AA4 periods. Given the uncertainty surrounding expenditures and volumes delivered for AA4, the ACCC considers it more appropriate to minimise tariff shock between the AA2 and AA3 periods and to apply an increasing price path over the period. The ACCC considers this will minimise price shock to users, whilst still allowing GasNet to recover its revenue.

The ACCC notes that in regard to Origin Energy's concern to avoid future price shocks, GasNet's proposed new revenue control provides GasNet with the ability to adjust its forecast volumes and tariffs over the remaining years of the AA period.[543] By allowing GasNet to adjust both its tariffs and forecast volumes GasNet will be better able to manage the movement in its average tariff during the AA period. Accordingly, the ACCC considers that GasNet's proposed revenue control model will better enable GasNet to control the movement in its average tariff between the AA3 and AA4 periods.

6.2.6 Conclusion

The ACCC proposes to accept GasNet's proposed tariff movement over the AA3 period, but does not propose to accept the initial level of average tariffs at the commencement of the AA3 period. The ACCC considers that given uncertainty regarding GasNet's expenditures for the AA4 period and in order to minimise tariff shock between the AA2 and AA3 periods, GasNet's proposed X factor of –2.8 per cent provides a reasonable balance between the interests of users and prospective users and GasNet's legitimate business interests. Whereas, GasNet's proposed initial average tariff does not reflect the lower revenue requirement and higher volume forecasts proposed by the ACCC.

[543] GasNet's proposed new revenue control is considered in chapter 6.3 of this draft decision.

6.3 Reference tariff variation policy

6.3.1 Code requirements

Section 8.3 of the code provides discretion to service providers in how the reference tariffs may be varied during an AA period to recover revenue. This discretion is subject to s. 8.3A of the code (reference tariff variation method) and the relevant regulator being satisfied that the proposed methodology is consistent with the objectives of s. 8.1 of the code.

In accordance with s. 8.3 of the code, the tariff variation methods available to the service provider include:

- cost of service
- price path
- reference tariff control formula approach
- trigger event adjustment approach and
- any variation or combination of these.

Section 8.3A of the code states that if a reference tariff varies within an AA period, then it must do so in accordance with the requirements and procedures set out in ss. 8.3B–8.3H of the code. Under these sections, the service provider is required to provide information to the relevant regulator (for the purposes of assessment) upon the occurrence of a specified event or when it otherwise intends to vary a tariff in accordance with an approved reference tariff variation method. The relevant regulator's power to allow, or disallow a variation and specify a variation which is consistent with the reference tariff variation method are set out, as is the relevant regulator's requirement to publish reasons. The code allows the relevant regulator to specify its own variations, if a specified event occurs and the service provider does not serve a notice.

6.3.2 Current access arrangement provisions

6.3.2.1 Price control formula—average revenue yield control

An average transmission tariff (ATT) (an average revenue yield), was set for the access period based on a forecast of tariff mix including the:

- location of injections and withdrawals on the system (i.e. across differing tariff zones)
- customer type usage (i.e. between tariff-D and tariff-V user tariffs) and
- time of year usage (i.e. the proportionate relationship between peak and annual volumes).

To the extent that the yearly actual tariff mix has differed to the forecast tariff mix over the AA period a deviation has occurred between actual revenue and permitted revenue (based on a set ATT). This deviation (referred to as the K-factor) has been corrected over the remainder of the AA period through tariff adjustments. Any remaining K-factor amount, in accordance with fixed principle 7.1 of GasNet's second AA, will be passed through to the AA3 period. For the second AA:

- GasNet is able to earn its approved revenue irrespective of where volumes occur within the PTS, across the 69 tariff components comprising the tariff mix as long as actual volumes in total equal or exceed total forecast volumes[544]
- GasNet's revenue is volatile only to total annual withdrawal volume deviations from forecast.
- tariffs have varied in accordance with a K-factor adjustments (accounting for the deviation between actual revenue and allowed revenue, based on the set ATT) and
- individual tariffs have been subject to a CPI–X+Y price control.

The K-factor adjustment and the individual price control on tariffs of CPI–X+Y are considered in chapter 6.2 of this draft decision. Also considered in chapter 6.2 is that GasNet, in accordance with a cost of service approach has passed through some defined pass through event costs (positive and negative) over the current period. This has also caused some tariff movement however the influence of pass through events on tariffs has been much more minimal than the impact of tariff mix outcomes.

6.3.2.2 Procedure for reference tariff variation

GasNet's procedure for varying tariffs (on an annual basis) in the current period is contrasted to its proposed AA in table 6.3.1 below.

6.3.3 Proposal

6.3.3.1 Price control formula—Modified average revenue yield control

The modifications to its AA2 price control formula that GasNet proposes are to constrain its exposure to total volume risk through two mechanisms.

One mechanism makes revenue outcomes neutral to EDD forecasts (forecasts of cold weather impact on volumes).[545] The second mechanism GasNet proposes is to bound weather adjusted volume outcomes to +/–5.5 per cent of the original volume forecasts, effectively bounding non (cold) weather related volume risk.

As a basis for its proposed limitations on volume risk, GasNet states a concern that the current revenue control method exposes GasNet to potentially very large revenue shortfalls because of cold weather outcomes. It notes that for the AA2 period:

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544 GasNet, *GasNet Australia Access Arrangement—Application to revise*, 24 August 2004, p. 8. The application referred to 69 tariff components.

545 A detailed consideration of EDDs in the context of volume forecasting is in chapter 5.4 of this draft decision.

- it forecasts gas volumes will fall below original volume forecasts by an average of 4.6 per cent per annum and
- in 2005 actual volumes were 11.4 per cent below forecast.[546]

GasNet considers that revenue shortfalls however, are only weakly related to cost reductions because:

- savings in fuel gas costs are relatively low to the revenue lost from lower volumes resulting from a warmer than expected year and
- the relationship of overall demand to the asset augmentation program is weak.[547]

In relation to cold weather risk, GasNet sets out in its submission that:

> ….it proposes to adjust actual delivered gas volumes to reflect the volumes that would be expected in a standard winter. The standard winter is defined by the number of effective degree days as published in the VENCorp APR, which is the basis for the volume forecast proposed by GasNet over the Third Access Arrangement Period.[548]

Secondly, in terms of other non-cold weather related volume risk, GasNet proposes to introduce symmetrical bounds to limit its exposure to other categories of risk. GasNet refers in relation to other categories of risk to only economic growth factors. Specifically, it does not refer to electricity market outcomes and the impact on revenue associated with volatility in gas usage by gas power generation (GPG) which may occur as a result of summer (hot weather) and winter (cold weather) outcomes as well as electricity market competition outcomes generally. The ACCC understands from discussions with GasNet, however, that it also intends GPG outcomes to also be within the same +/–5.5 per cent bounds. As considered also in chapter 5.4 of this draft decision, GasNet notes that the volume risk bounds represent the maximum deviations in terms of upper and lower forecasts from the medium economic growth scenario forecast in the VENCorp 2006 GAPR. It submits that (volume) deviations outside the range are indicative of abnormal events, which GasNet should not be exposed to.[549]

GasNet's change from AA2 to constrain total volume risk results in a proposed price control formula for AA3 which differs to that proposed for AA2. The changes are outlined below. In accordance with GasNet's price control formula the terms initial / adjusted target revenue have been used below. These terms represent the initial revenue and changed revenue over the access period which GasNet will be allowed to keep under its modified average revenue yield control where allowed revenue adjusts such that GasNet keeps the benefits and losses of some (not all) volume outcomes different to forecast:

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546 id., *Submission*, op. cit., p. 105.

547 ibid.

548 ibid., p. 106.

549 ibid., p. 107

- *Weather adjusted actual volumes* (WAAV)—GasNet proposes to remove its volume risk related to cold weather (EDD) outcomes by requiring weather adjusted actual volumes (WAAV) to equal volumes withdrawn (VW) after adjusting VW for ΔEDD×TJ/EDD sensitivity.[550]. This accords with cl, 4.6 of schedule 4 of GasNet's proposed AA.
- *Adjusted target revenue* (ATR)—GasNet proposes as part of bearing some volume risk/reward to allow initial target revenue to adjust upwards or downwards to match WAAV achieved times the fixed average revenue yield. This concept however is subject to the constraints/bounds of the volume risk factors (VRF) considered below. This is in accordance with cls. 4.3 and 4.4 of schedule 4 of GasNet's proposed AA.[551]
- *Volume risk factors* (VRF)—For the AA3 period, GasNet proposes to bound its volume risk and hence revenue risk, by allowing revenue to be calculated on the basis of WAAV. However, if WAAV should deviate more than +/–5.5 per cent from initial forecast volumes then the WAAV value will not apply in the calculation of ATR instead adjusted actual volumes (AAV) will apply which will be equal to initial forecast volumes +/–5.5 per cent as the case may be. This is in accordance with cl. 4.5 of schedule 4 of GasNet's proposed AA.
- *No exclusion of certain tariffs*—For the AA2 period, GasNet excluded from the price control formula: transmission refill tariffs, the Murray Valley incremental withdrawal tariff and the Port Campbell injection tariff. In AA3 there are no proposed exclusions (see cl. 4.1 of GasNet's second AA).

For the AA3 period, GasNet proposes to retain the following elements of its price control formula from AA2:

- *Pass through carry forward principle from AA2*—GasNet can pass through costs in AA3 which can be categorised as a pass through event which occurred in AA2 but were not identified in AA2. This is in accordance with fixed principle 7.3 of its second AA.
- *K-factor carry forward principle from AA2*—GasNet can recover any under-recovered/ over-recovered revenue from AA2 in tariffs for AA3. This is in accordance with fixed principle 7.1 of its second AA.[552].
- *Allowed average revenue yield*—GasNet will not bear tariff mix risk. This is in accordance with cl. 4.4 of schedule 4 of its proposed AA.

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550 ΔEDD = the difference between actual EDD and forecast EDD. There is also a 0.85 factor which the ACCC proposes to remove as detailed in this chapter.

551 GasNet's adjusted target revenue will also be affected by pass-through events and carried forward amounts from the AA2 period: see GasNet, *Proposed AA*, op. cit., cl. 4.3.

552 This is considered in chapter 6.1 of this draft decision in the context of cost allocation and tariff structures.

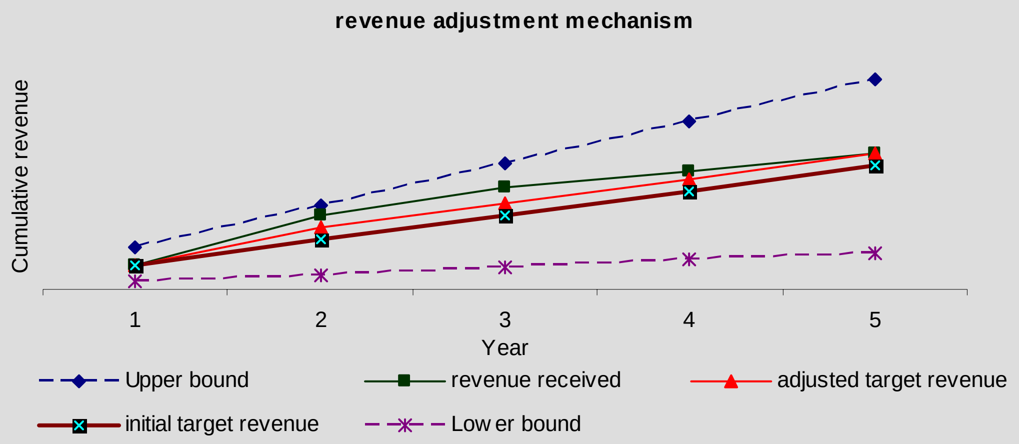
- *Pass through costs (negative or positive)*—GasNet can pass through costs of events in AA3. This is in accordance with cl. 4.3 of schedule 4 of its proposed AA.
- *Carry forward principle into AA4*—any under-recovered/over-recovered revenue from AA3 is to be passed through to tariffs for AA4. This is in accordance with cl. 7.1, and cls. 4.7 and 4.8 of schedule 4 of its proposed AA.
- *Pass through carry forward principle into AA4*—GasNet, as it did for AA2, proposes that it be a fixed principle that it be able to apply to pass through costs into the next period (AA4) which can be categorised as relating to a pass through event where the event occurred in AA3 but was not identified in AA3. This is in accordance with cl. 7.3 of its proposed AA.

For AA3, GasNet proposes to make annual (calendar year) tariff adjustments, in order that the actual revenue received and the remaining forecast revenue to be received over the access period will be no greater than the adjusted target revenue in NPV terms. This is the overriding control set out in cl. 4.1 of schedule 4 of the proposed AA in accordance with cls. 4.1 and 4.2.

- GasNet must account for actual revenue it has received and the forecast likely actual revenue it will receive over the period (accounting for forecasts of tariff mix, EDDs, inflation).
- GasNet will adjust individual tariffs for each year of the regulatory period such that actual revenue it forecasts to be received over the period in cumulative terms is to be no greater than the adjusted target revenue for the period in NPV terms. (This approach is similar to the existing K-factor adjustment for AA2, whereby tariffs are adjusted upwards/downwards to ensure that actual weighted average revenue received will not exceed allowed weighted average revenue).

GasNet's proposed approach can be explained by reference to box 6.3.1.

Box 6.3.1: Example of GasNet's proposed tariff control



* This is a stylistic representation: 5.5 per cent bounds on revenue outcomes limit total revenue gain or loss over the period against the building block revenue to +/–$25 m approximately (nominal) based on GasNet's capex proposals.

1. This chart depicts cumulative revenue over the access period.
2. An ***initial target revenue*** (i.e. building block revenue) in NPV terms over the AA period is determined at the commencement of the revised AA, as approved by the regulator.
3. GasNet proposes that both positive and negative symmetrical adjustments to the ***initial target revenue*** will occur on an annual basis, where there are volume deviations from forecast (i.e. volume deviations from forecast that are not related to the weather). However, these revenue adjustments are to be constrained by upper and lower bound of 5.5 per cent of actual volume deviations from forecast. The dashed lines in the Figure represents the limit of risk that GasNet and will bear.
4. In the Figure, for Year 2 ***initial target revenue*** has deviated up to the line shown as ***adjusted target revenue*****,** following some non-cold weather related volume growth in year 1.
5. The Figure also depicts a scenario that in year 2, a deviation has occurred between ***actual revenue received*** and the ***adjusted target revenue*****.** This could represent some weather related revenue which cannot be retained**.** This difference has to be re-paid over the AA period. In the Figure, this is shown by the movement of ***actual revenue received*** to coincide with ***adjusted target revenue*** over remaining years of the AA period. This movement is accomplished by annual tariff adjustments.
6. Where ***actual revenue received*** deviates from ***adjusted target revenue*** under GasNet's proposed revenue control model, deviations could occur because:
   - weather outcomes that are different to forecast;
   - actual weather adjusted volumes outside the allowed 5.5 per cent bounds;
   - actual tariff mix which is different to forecast; and/or
   - actual inflation different to forecast as initial target revenue will be set on the basis of an inflation forecast over the AA period.

All of these factors could influence annual tariff movements within the AA period. As noted above, GasNet's proposal is to smooth tariffs over the remainder of the period such that AA3 cumulative ***actual revenue received*** converges with the cumulative ***adjusted target revenue***.

As for AA2 GasNet proposes that tariffs can vary within the AA3 period in accordance with firstly pass through events and secondly, as noted in box 6.3.1 above, its price control formula an overriding control on ‘allowed’ revenue. GasNet proposes, a CPI–X+Y constraint on yearly individual tariffs movements:[553]

- tariffs for AA3 have been initially set on the basis of a standard CPI–X price path incorporating an annual CPI forecast of 3.09 per cent
- the X-factor for individual tariffs over the period is –2.8 per cent or 0 per cent[554]
- Y is 2%, except where the forecast transmission tariffs all escalated at CPI–X+2 for the remainder of the AA3 period would provide insufficient revenue to achieve the adjusted target revenue. Where this occurs, Y may be more than 2 per cent in respect of a component of the transmission tariffs provided that the resulting transmission tariff does not exceed the tariff price path that would have eventuated if the standard CPI–X price path had been followed for that component of the transmission tariff over the entire AA3 period. [555]

GasNet does not comment in its submission as to why it proposes including an exception, which did not exist for AA2, to constraining Y at 2 per cent. However, the mechanism proposed indicates an intent by GasNet to further decrease (compared to AA2) the chance of carrying forward into the next period any under-recovery against allowed revenue through relaxing the initial tariff ceiling in certain circumstances.[556]

6.3.3.2 Procedure for reference tariff variation

GasNet’s proposals in relation to the method/timing of proposed tariffs changes in the event of a pass through event are set out in cl. 6 of its proposed AA. In relation to variations based on it price control formula, these are set out in schedule 3 of its proposed AA. The key differences to AA2 proposals are summarised below in table 6.3.1 by comparison to proposals for the AA2 period.

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553 GasNet describes the ‘CPI–X+Y’ framework in schedule 4 of its access arrangement as (CPI–X)(1+Y). The ACCC’s understanding is that models provided to it to date include a tariff alteration mechanism of T×CPI(1–X)(1+Y). In this decision the term CPI–X+Y is used as a shorthand expression to indicate the price path more fully contained in GasNet’s models of T×CPI(1–X)(1+Y).

554 Those tariffs subject to an X factor of 0 per cent are considered in chapter 6.1 of this draft decision.

555 GasNet, *Proposed AA*, op. cit., schedule 4.

556 AER staff confirmed this intention with GasNet at a meeting on 22 August 2007.

Table 6.3.1: Comparison of approval process between AA2 and AA3

AA2	*AA3*
Submit pass through event statement 50 business days before start of the regulatory year	Submit pass through event statement 50 business days before start of the regulatory year
Statement is taken to be approved if the relevant regulator does not give notice within 40 business days	Statement is taken to be approved if the relevant regulator does not give notice within 20 business days
Submit tariff proposal at least 30 business days before the end of the regulatory year	Submit tariff proposal at least 20 business days before the end of the regulatory year
Proposal is taken to be approved if the relevant regulator does not notify GasNet of a decision within 20 business days of the Regulator receiving a statement.	Proposal is taken to be approved if the relevant regulator does not notify GasNet of a decision within 15 business days of the regulator receiving a statement.
Practically, the relevant regulator can make a decision on both the pass through event and the tariff proposal at the same time.	Practically, the relevant regulator must make two separate decisions.
N/A	When an AA is revised under the code GasNet may specify a start date on which 'revised tariffs' will commence before the start of the next AA period. GasNet specifies a 15 day assessment period

GasNet does not comment in its submission on these substantial changes including the new clauses, cls. 3.6–3.8 in schedule 3 of the proposed AA. Further, GasNet does not address the fact that since its AA2 proposal, substantial changes to the code have occurred, effective from 6 February 2003, stipulating that a reference tariff may vary within an AA period only through implementation of the approved reference tariff variation method as provided for in ss. 8.3B–8.3H in accordance with s. 8.3A of the code.[557]

6.3.4 Submissions

TRUenergy submits that modifications to the average revenue yield result in reduced weather volume risk and consider that there should be an adjustment to the WACC.[558] AGL also questions whether the WACC proposed by GasNet should be modified to reflect the lower volatility in revenue yield that this revised control mechanism will bring about.[559]

557 'Fourth Amending Agreement' which came into operation on 6 February 2003.

558 TRUenergy, op. cit., p. 9.

559 AGL, op. cit., p. 2. Submissions relating to the WACC are considered in chapter 4 of this draft decision.

6.3.5 Assessment

6.3.5.1 Price control formula—modified average revenue yield control

GasNet has provided the ACCC with a model supporting the price control formula it proposes in schedule 4. The ACCC has assessed GasNet's price control formula alongside the model. This model clarifies a number of aspects of the price control formula explained in schedule 4. The ACCC has audited this model and proposes amendments below to schedule 4 on the basis of the proposed AA and model provided.

GasNet's proposed form of price control is described by it as a reference tariff control formula approach which is a permissible form under the code.[560] However, in addition, the form of price control also exhibits:

- a price path approach[561] as evidenced by the initial setting of tariffs in accordance with a CPI–X standard price path
- a cost of service approach[562] in relation to the revenue requirements and
- a trigger event adjustment approach as represented by the allowance within the model for pass through events.[563]

Section 8.3(e) of the code specifically allows any variation or combination of approaches. The ACCC considers that the form of control proposed by GasNet is an allowable form of control under the code.

(i) *Risk sharing under the proposed form of price control*

GasNet proposes to modify its form of control to limit its exposure to total volume risk by eliminating cold weather (EDD) risk and bounding total volume risk to +/– 5.5 per cent of original volume forecasts. The ACCC understand that GasNet aims to reduce its revenue risk from actual volumes deviating from forecast based on an assessment that it is a largely fixed cost business. Bounds around GasNet's revenue for AA3 also bound total users payments within a minimum and maximum.

GasNet submits that there is likely to be an under-recovery against initial approved building block revenue of 4.6 per cent, as a result of total volume shortfalls (against forecast) for AA2.[564] The ACCC has not placed great weight on these forecasts as being indicative of GasNet's actual exposure to volume outcomes over AA2 because it understands GasNet's projected shortfall based on early 2007 analysis does not incorporate the now apparent high 2007 GPG usage. This higher usage is likely to significantly reduce any revenue shortfall experienced by GasNet over AA2. Nevertheless, the ACCC notes that GasNet is exposed yearly to a substantial risk

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560 Code, s. 8.3(c).

561 Code, s. 8.3(b).

562 Code, s. 8.3(a).

563 Code, s. 8.3(d).

564 This is considered in chapter 5.4 of this draft decision.

that volumes will deviate from forecast volumes under its current average revenue yield. This is highlighted in GasNet's submission by its comments that in 2005 actual volumes were 11.4 per cent below forecast.[565] The ACCC notes that the revised forecasts of GPG volumes, as considered in chapter 5.4 of this draft decision, means volume forecasts are likely to be unbiased estimates such that GasNet and users will share equally in potential upside and downside volume risk and its impact on tariffs. As part of its proposed price control, the ACCC considers GasNet's approach to make revenue neutral to weather warming, is a reasonable response to managing risks which are outside GasNet's control. For GasNet, this is especially important given the inherent uncertainty as to weather outcomes as evidenced by the variation across AA2, as set out in table 5.4.5 in chapter 5.4 of this draft decision.[566]

The ACCC notes that shortfalls in GPG usage during the AA2 period up to the end of 2006 represent half of GasNet's estimated under-recovery of revenue for the AA2 period.[567] The ACCC considers that GPG usage remains a significant factor in terms of introducing volatility to GasNet's revenue stream because GPG output in the electricity market is volatile to many factors including summer and winter weather (and also drought effects caused by low rainfall generally).

The ACCC considers that GasNet's proposed 5.5 per cent bounds on weather adjusted actual volumes to be a not inappropriate cap on the risk/reward for GasNet and users. The ACCC noted in chapter 5.4 of this draft decision that the relationship of these bounds to the high and low volume forecast scenarios of economic growth for the 2007–11 planning period in VENCorp's 2006 GAPR. The ACCC has reviewed the basis of these differing economic growth scenarios and considers they reflect volume expectations which take into account those factors which a business might consider in projecting future volumes. Any other factors not included within these scenarios could be considered to be unexpected.[568]

(ii) *FCA carryover fixed principle*

GasNet's proposed price control formula contains two carry-forward amounts affecting tariffs in the AA4 period. The first amount relates to the estimated difference between actual and adjusted target revenues for the AA3 period which is to be included in tariffs to apply in 2013. A second amount represents a correction for the first amount using actual data for AA3, which is to be included as an adjustment in 2014 tariffs.

The ACCC considers these adjustments to be consistent with s. 8.1(a) of the code. It is noted that while the second carry-forward amount is to be adjusted for inflation to

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565 See table 5.4.5 in chapter 5.4 of this draft decision.

566 CSIRO, *Projected changes in temperature and heating degree-days for Melbourne and Victoria, 2008-2012*, March 2007, p. 50: CSIRO baseline 2006 EDD (1321), VENCorp baseline 2006 EDD (1362). See chapter 5.4 of this draft decision.

567 See table 5.4.5 in chapter 5.4 of this draft decision.

568 VENCorp, *2006 Gas Annual Planning Report*, appendix A.

December 2014, the actual amount of this inflation will not be known at the time this amount is calculated.

The ACCC considers that GasNet's price control formula is within the service provider's discretion. The ACCC notes in general it represents a balance between having some incentive to develop the market, whilst ensuring sufficient revenue to recover fixed pipeline costs. GasNet's proposal to limit its revenue at risk to ensure that its fixed costs can be recovered is consistent with allowing the service provider the opportunity to earn a stream of revenue that can recovers its efficient costs[569] and which will be sufficient to ensure the safe and reliable operation of the pipeline.[570] From a user's perspective, capping revenue outcomes near to GasNet's proposed costs for the period will minimise the potential for investment to be distorted through tariffs which deviate away from long run average costs.[571] However, by bearing some risk GasNet will still retain an incentive to expand the market consistent with s. 8.1(f) of the code. The ACCC has however identified some issues within the formula, which it considers requires amendments in order for s. 8.1 of the code to be satisfied.

(iii) *Definition of actual revenue (AR)—clause 4.2 of the proposed AA*

As considered in chapter 5.5 of this draft decision, the ACCC considers that AMDQ revenue should be accounted for in the proposed AA. Accordingly, the ACCC proposes the following amendment.

Proposed amendment 23

Before the proposed revised access arrangement can be approved, GasNet must insert the following directly below the heading 'AR' in schedule 4.2 of the proposed revised access arrangement:

> 'For the avoidance of doubt, actual revenue includes revenue derived from authorised maximum daily quantity/credit certificates as allocated under the Market and System Operations Rules.'

As considered in chapter 5.5 of this draft decision, the ACCC proposes GasNet be able to claim its costs as part of the provision of this service.

(iv) *Weather adjusted actual volume (WAAV) formula*

GasNet proposes a formula to adjust revenue received to remove the influence of cold-weather outcomes on its recoverable revenue. This formula is set out at cl. 4.6 of schedule 4 of its proposed AA:

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569 Code, s. 8.1(a).

570 Code, s. 8.1(c).

571 Code, s. 8.1(d).

$$WAAV = actual\,VW + TS \times \left(target\ EDD - actual\ EDD\right) \times 0.85$$

where:

WAAV	weather-adjusted actual volume	*VW*	volumes withdrawn
TS	temperature sensitivity	*EDD*	effective degree days

This formula also includes GasNet's proposed adjustment to account for the correlation between the EDD and fuel gas use (the 0.85 multiple in the formula). As a consequential amendment contingent on the ACCC requiring as part of this decision GasNet to treat deviations from the fuel gas base forecast as a pass through event the ACCC proposes the following amendment.

Proposed amendment 24

Before the proposed revised access arrangement can be approved, GasNet must amend the formula in schedule 4.6 of the proposed revised access arrangement to read:

'$WAAV = actual\,VW + TS \times \left(target\ EDD - actual\ EDD\right)$'

(v) *Definition of actual volume withdrawn (VW)—cl. 4.6 of the proposed AA*

Culcairn expansion

GasNet includes the following definition in its formula in cl. 4.6 of schedule 4 of its proposed AA:

> VW is the actual volume withdrawn from the PTS excluding any volumes associated with an Expansion of withdrawal capacity at Culcairn.

GasNet does not comment on its proposed definition in its submission. The ACCC assumes that the exclusion in its definition relates to its proposed extensions and expansions policy where GasNet proposes that an expansion beyond the current capacity for withdrawal at Culcairn be uncovered, if GasNet gives notice to the regulator. GasNet's proposed definition may provide an anomalous outcome, if GasNet's allowed regulated revenue under the revenue control model could increase despite the expansion being uncovered and earning non regulated revenue. The ACCC has proposed not to approve GasNet's proposal that an expansion of capacity over and above the current capacity of 17 TJ/day at Culcairn will be automatically uncovered upon written notice to the relevant regulator.[572] As the ACCC proposes this amendment to the extensions and expansions policy, a consequential amendment is proposed to the definition of VW in schedule 4.6 as noted below.

[572] As considered in chapter 5.4 of this draft decision,

Transmission refill tariff

As considered in chapter 5.4 of this draft decision, the ACCC requires an amendment to remove refill volumes from the average revenue yield control.

Murray valley tariff

As considered in chapter 6.1 of this draft decision, the ACCC considers that the incremental Murray Valley tariff should be tariffed outside the average revenue yield control.

Proposed amendment 25

Before the proposed revised access arrangement can be approved, GasNet must amend the definition of VW in schedule 4.6 of the proposed revised access arrangement to read:

‘VW is the actual volume withdrawn from the PTS excluding:

- any volume withdrawn from a non-covered expansion of withdrawal capacity at Culcairn
- any transmission refills at the Western Underground Storage or Liquefied Natural Gas facility at Dandenong and
- forecast volumes for the incremental Murray Valley tariff.’

(vi) *Definition of VATR—cl. 4.4 of the proposed AA*

In order to remove the revenue and volumes for the transmission refill tariff and the Murray Valley tariff fully from the price control formula, as discussed above under amendments to cl 4.6 of the proposed AA, it is necessary to remove forecast volumes and revenues from GasNet’s initial allowed revenue yield. Consequently, the ACCC proposes the following amendment 26:

Proposed amendment 26

Before the proposed revised access arrangement can be approved, GasNet must amend the definition of VATR in schedule 4.4 of the proposed revised access arrangement to remove from TR and TV as defined therein revenues and volumes associated with:

- any transmission refills at the Western Underground Storage or Liquified Natural Gas facility at Dandenong and
- the incremental Murray Valley tariff.

(vii) *TJ/EDD sensitivity (TS)—cl. 4.6 of the proposed AA*

GasNet’s price control formula in cl. 4.6 of schedule 4 requires it to include a value for the sensitivity of gas volumes to an effective degree day (TJ/EDD) for the purposes of removing cold-weather (EDD) outcome effects on revenue. However, as discussed with GasNet, the proposed TJ/EDD values are not consistent with

VENCorp's estimates used to derive the demand forecast over 2007-2011 and with the additional TJ/EDD forecasts for 2012 submitted to GasNet by VENCorp.

The ACCC notes that the data in the AAI is incorporated in to schedule 4 of GasNet's proposed AA and that this data is currently incorrect. Section 2.30 of the code allows the ACCC to require GasNet to make changes to the AAI when it does not satisfy the requirements of s. 2.6 of the code. The ACCC notes s. 2.6 of the code requires the AA to contain such information to enable users and prospective users to understand the derivation of the elements of the proposed AA. This requirement would not be satisfied if GasNet was to include incorrect data different to that used in the calculation of tariffs.

Accordingly, the ACCC proposes that GasNet replace current temperature sensitivity values within its AAI, with the TJ/EDD sensitivities adopted by VENCorp.

Proposed amendment 27

Before the proposed revised access arrangement can be approved, GasNet must amend Table 7-1 in cl. 7.1 of its revised access arrangement information to include the temperature sensitivities used by VENCorp for its annual demand forecasts in its 2006 Gas Annual Planning Report.

(viii) *Individual tariff control—cl. 4.1(ii)(B) of the proposed AA*

In relation to its CPI–X+Y reference tariff control GasNet proposed for Y:

- *An initial constraint*—Y is 2%.
- *Relaxed constraint*—if an under-recovery against adjusted target revenue would still (is forecast to) arise at the end of the period, if Y=2% was applied over all tariffs for the remainder of the period. In this circumstance, GasNet proposes removing this 2 per cent ceiling and replacing it with Y being any amount, subject to Y not being such that the resultant tariffs exceeds the tariff that would have eventuated if the standard CPI–X price path had been followed for that component of the transmission tariff over the entire AA3 period.

GasNet made no submissions on its proposal to include this new (from AA2) relaxed constraint. However, from brief discussions with GasNet, the ACCC understands that GasNet intends to materially minimise amount of likely unrecovered revenue at the end of the AA period. Relevantly, the ACCC notes that during AA2:

- GasNet made a non-scheduled application in 2004 to revise its AA where it proposed a revision to allow it to smooth tariffs over the remainder of the AA period by allowing K-factor amounts (over/under recovery of revenue) to be smoothed over the remainder of the period.
- As part of its application GasNet also considered a further option (rebound to price path) of not having a smoothing mechanism but allowing tariffs to rebound back up to the price path in any year. That is, in a year following a year in which a large tariff decrease (from the price path) occurred, in order

to repay a large revenue over-recovery, a large tariff increase could occur back to the price path.

- GasNet noted in its AA2 proposal, the benefits of a smoothed mechanism as to limit the variation in tariffs that might otherwise occur from a full tariff rebound to price path.
- The ACCC approved this revision but stated it would consider further, the appropriate adjustment mechanism for AA3 at the AA3 revisions.[573]

Specifically as part of this application GasNet noted that:

> GasNet's preference is for option 2 since this leads to a smoother tariff path over time, and retains the 2% cap on individual tariff increases.[574]

In assessing GasNet's proposal for AA3, the ACCC has considered the likely circumstances which would lead to a situation where a relaxing of the 2 per cent side constraints would be necessary. In particular, it is noted that:

- An individual tariff increase above CPI–X+2 is most likely to occur towards the end of the AA period (in the final year), as GasNet proposes to be able to adjust tariffs on an annual basis for forecast variations between achieved revenue (actual revenue received) and adjusted target revenue (allowed revenue). That is, targeting revenue back over all remaining years to comply with the principle that for the 5 year period the NPV of actual revenue can be no greater than adjusted target revenue.
- It is not inconceivable that tariffs could rise 20 per cent in the last year given certain circumstances.[575] These circumstances might arise where tariffs are already below the initial standard price path and GasNet recovers well below its 'weather adjusted actual volume' because of exceptionally warm weather in the penultimate year of the period.[576] This happens in conjunction with other factors (inflation different to forecast, tariff mix outcome).[577]
- Ultimately, any incremental revenue shortfall, resulting from limiting tariff movements to CPI–X+2, can be passed through to users in AA4 within its building block (inflation escalated) in accordance with fixed principles in cls. 7.1 and 4.7, 4.8 of schedule 4 of its proposed AA.

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[573] GasNet, *Application to Revise 2004*, op. cit., pp. 6–13; ACCC, *Final Decisions: GasNet Australia—access arrangement revisions for the GasNet System*, 15 December 2004, pp. 11–15.

[574] GasNet, *Application to Revise 2004*, op. cit., p. 9.

[575] The ACCC notes that tariffs under the AA3 proposals could be substantially more than during the AA2 period because of GasNet's approach to bound volume risk. For AA2, tariffs would not have varied as a result of EDD outcomes different to forecast meaning intra-period tariff volatility was considerably more constrained. The potential size of tariff increases is much greater than the potential large increases that the ACCC considered in the context of GasNet's consideration of a rebound to price path approach for AA2. See ACCC, *Draft Decisions:GasNet Australia access arrangement revisions for the GasNet system*, 10 November 2004.

[576] See, e.g., 2005 outcomes in table 5.4.5 in chapter 5.4 of this draft decision.

[577] It is noted that with an X factor of –2.8% any allowed tariff adjustment above CPI–X+2 would be an allowance of some amount greater than 8 per cent under GasNet's proposals.

In considering GasNet's proposal, the ACCC has considered the objectives in s. 8.1 of the code:

- GasNet's proposal is consistent with allowing GasNet the opportunity to earn a stream of revenue to recover its efficient costs within the AA period.[578] However, allowing unrecovered amounts to be collected within the following access period is also consistent with this objective although it could be argued allowing the service provider to recover more of these costs in this period is more consistent with this objective.
- Large variations year to year, to the extent they exceed 8 per cent and approach 20 per cent appear inconsistent with replicating the outcome of a competitive market where a business might be constrained by competition from adjusting tariffs up markedly in a year.[579] Large price increases might also distort investment decisions when users respond to such changes as evidencing a volatile market.[580]

The ACCC considers GasNet's proposal meets some but not all of the objectives in s. 8.1 of the code. The ACCC has thus considered the proposals against s. 2.24 of the code in exercising its discretion to resolve this conflict in meeting the objectives. The ACCC notes that:

- Allowing GasNet to include a policy which provides a mechanism which guarantees the recovery of adjusted target revenue within the AA period protects the service provider's commercial interests[581] and allows it to recover total costs within the period which reflect the economically efficient operation of the pipeline.[582] However, as noted above allowing unrecovered amounts to be recovered in the following period is also consistent with this principle.
- One off large tariff increases, such as 20 per cent, would appear not to be in the interests of users or prospective users[583] or the public interest, including public interest in competition[584] if there is an approach to avoid these price variations.
- Maintaining Y at 2 per cent may cause larger amounts to be passed through into AA4. However, within AA4 tariffs, the AA3 under-recovered sum would be recoverable over a longer period of time facilitating a potential smoother tariff escalation to recover any unrecovered sums from AA3. This

578 In accordance with s. 8.1(a) of the code.

579 In accordance with s. 8.1(b) of the code.

580 In accordance with s. 8.1(d) of the code.

581 In accordance with s. 2.24(a) of the code.

582 In accordance with s. 2.24(d) of the code.

583 In accordance with s. 2.24(f) of the code.

584 In accordance with s. 2.24(e) of the code.

> approach seems more consistent with GasNet's general smoothing mechanism implicit in its price control formula intra-period. Removing tariff volatility in the last year would appear to be in the interest of users and the public interest.[585]

The ACCC considers that carrying forward the sum better balances the interests of users and prospective users and the public interest, including the public interest in having competition in markets. At the same time, the businesses interests[586] are protected by allowing it to carry forward this un-recovered amount, escalated for inflation into the AA4 building block calculation. Users' interests are also protected by being able to consult on AA4 tariffs when GasNet proposes its next AA. The ACCC further considers that GasNet can in part mitigate its own risk in accordance with its tariff smoothing mechanism by incorporating best forecasts and should be provided incentives to do so, rather than potentially relying on the ability to relax the constraint. On balance, the ACCC considers GasNet's proposal to relax the 2 per cent side constraint should not be approved.

Proposed amendment 28

Before the proposed revised access arrangement can be approved, GasNet must amend schedule 4.1(a)(ii)(B) of the proposed revised access arrangement and remove all the words which follow 'Y is 2%'.

6.3.5.2 Procedure for reference tariff variation

(i) *Changes to the code subsequent to AA2*

As noted above GasNet does not address the fact that since its AA2 proposal, substantial changes to the code have occurred, effective from 6 February 2003 stipulating that a reference tariff may vary within an AA period only through implementation of the approved reference tariff variation method as provided for in ss. 8.3B–8.3H.[587] In fact, GasNet provides no submission in relation to its procedures for how reference tariffs will vary over the AA3 period.

(ii) *Trigger event adjustment approach and reference tariff control formula*

A trigger event adjustment mechanism is included in cl. 6 of the proposed AA in relation to pass through events. Pass through events are defined within cl. 9 of the proposed AA. Clause 4.3 and schedule 3 of GasNet's proposed AA sets out a method for tariffs to vary in accordance with a reference tariff control formula approach, with the formula specified in schedule 4.

Any pass through event statement, in accordance with cls 6.1 and 6.2 of the proposed AA, must be submitted at least 50 business days before the end of the year and

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585 In accordance with ss. 2.24(e) and 2.24(f) of the code.

586 In accordance with ss. 2.24(a) and 2.24(d) of the code.

587 Code, s. 8.3A.

approved within 20 business days (changed from 40 business days) by the relevant regulator. That is, the statement must be approved before the notice setting out proposed tariffs for the following year under schedule 3 based on the reference tariff control formula is submitted (clause 3.1). This process appears to not fit well with the code which requires that on the occurrence of a specified event the service provider must provide the relevant regulator with proposed variations to the reference tariff.[588] That is, GasNet's proposed AA contemplates an approval process for pass through events which does not include notice of the proposed varied tariffs.

(iii) *Inconsistencies with ss. 8.3B–8.3H of the code*

A number of aspects of GasNet's proposals under cl. 6 and schedule 3 of its AA proposal appear difficult to reconcile with the approach provided for varying a reference tariffs provided for in ss. 8.3B–8.3H of the code. An example is set out in table 6.3.2.

Table 6.3.2: GasNet's process against ss. 8.3B–8.3H of the code

Clause 3.3(b) of schedule 3 The regulator <u>must</u> approve a statement given by GasNet under clause 3.1 of this Schedule if: Clause 6.2 The Regulator must approve the statement (pass through statement) unless…	Section 8.3E of the code The Relevant Regulator may, by notice to the Service Provider, before the variation is due to come into effect under s. 8.3D, disallow a variation of a reference tariff *combined with:* Section 8.3D of the code Unless the Relevant Regulator has disallowed the variation under section 8.3E, the Reference Tariff will be varied automatically

GasNet's proposals appear to convey a responsibility on the relevant regulator to approve GasNet's proposals whereas the procedure provided for in the code does not require the relevant regulator to approve a proposal.[589] That is, a positive obligation is put on the relevant regulator which is not anticipated under the code.

In addition to this example, cl. 3.4 of schedule 3 of the proposed AA purports to set a date on which the variations to the reference tariffs will take effect. This clause has been superseded by s. 8.3D of the code and should be removed.

Further, GasNet proposes in cl. 3.3(d) of schedule 3 that if the relevant regulator agrees then a statement (notice of proposed tariffs) can be replaced. However, this process does not seem to be envisaged under the procedures set out in ss. 8.3B–8.3H of the code. Instead, these procedures envisage the relevant regulator specifying a variation that is consistent with the approved reference tariff variation method when it may disallow a proposal.[590]

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[588] In accordance with ss. 8.3B and 8.3C of the code.

[589] In accordance with s. 8.3E of the code.

[590] In accordance with s. 8.3E of the code.

(iv) *The intent/effect of some proposals in GasNet's proposed AA is unclear*

Clauses 3.2 and 3.6 to 3.8 of schedule 3 of GasNet's proposed AA appear to be unnecessary given what is envisaged in s. 2 of the code.

GasNet proposes in cl. 3.2 of the proposed AA that 'it may alter a transmission tariff during a regulatory year in accordance with section 2'. Further, the ACCC understands from discussions with GasNet that cls. 3.6–3.8 of the proposed AA are intended primarily to allow GasNet to specify a start date for 'new tariffs' for a 'new' AA if it revises its AA during the AA period prior to the revisions commencement date through a non scheduled revision.

The ACCC considers these clauses are not necessary given the nature of an AA revision application under s. 2.28 of the code. At any time, GasNet may, at its discretion during the following AA period, propose revisions to the AA (inclusive of tariff revisions). Indeed, during AA2, consequent on a non scheduled revision the ACCC approved revisions on 15 December 2004 and exercised its discretion for these revisions to be reflected in tariffs from 1 January 2005. Equally, however, GasNet could have proposed and the ACCC could have accepted revisions to apply from 1 July 2005 if the timing of proposals were different. The nature of any AA revision could encompass new tariffs applying for example for half a year and further consequent revision processes in accordance with ss. 8.3B–8.3H of the code.

The ACCC considers that tariff revisions consequent on an AA revision (including the timing of such revisions), in accordance with the code, would be able to be dealt with at the time of the revision.

(v) *Approach taken by APT in Roma to Brisbane*

The ACCC notes that the ACCC approved for APT Petroleum Pipelines Limited (APT) an AA for the Roma to Brisbane Pipeline (RBP) with what appears to be a much more concise reference tariff variation method which referenced the code. The provisions relevantly included:

- the date by which a notice must be submitted and
- the minimum notice period for the purposes of s. 8.3(D)(b)(i) of the code.[591]

GasNet's proposal may be a degree more complicated that APT's proposal given the practicalities of implementing a once a year pass through based and a once a year price control formula based tariff variation. However, in principle, the ACCC considers that GasNet could and should simplify and make clearer its proposed arrangements by reference to the code. In fact the ACCC considers this is desirable to avoid the risk of GasNet's proposals in its AA differing from the principles set out in the code and resultant confusion.

[591] ACCC, *Approved Revised Access Arrangement: Roma to Brisbane Pipeline*, 28 March 2007.

(vi) *Shorter time frames envisaged in GasNet's proposed AA*

Notwithstanding the issues relating to code compliance considered above, as far as GasNet has nominated a minimum notice period for assessment, which is envisaged in s. 8.3D(b)(i) of the code, the ACCC considers that these periods proposed are insufficient.

In relation to pass through events, GasNet is proposing to reduce the time that the ACCC has available to make a decision on a pass-through notice from 40 business days to 20 business days. GasNet made no submissions on its proposal to reduce the time period for it to submit its annual tariff statement and for the ACCC to make a decision on the statement. The ACCC does not support GasNet's proposal. This issue was considered during the ACCC's assessment of the proposed AA for the AA2 period. An assessment period of 40 days was considered appropriate given the scope of the pass-through events, some of which may require public consultation. An assessment period of 20 days might be sufficient if the scope of pass-through events was limited to straight-forward, transparent events that did not require public consultation, such as a change in tax. However, the pass-through events proposed by GasNet are more complex than this and essentially the same as contained in the second AA. Accordingly, the ACCC does not support GasNet's proposal.

The ACCC also does not support GasNet's proposal to submit annual tariff proposals 20 business days before the end of the year and for the relevant regulator's decision to be made within 15 business days. The ACCC considers that requiring GasNet to submit its proposals more than 20 business days before the end of the year (but still towards the end of the year) would not disadvantage it. The ACCC does not expect that the estimates GasNet uses in its model would substantially change if this 20 day period was extended slightly. GasNet's price control formula enables it to replace estimates with actuals in the following year. Its price control formula means that there will be no ultimate revenue effect on GasNet in NPV terms from marginally more incorrect estimates, the effect of which is only temporary. Regardless, the ACCC considers that it needs more than 15 business days to enable it to better assess GasNet's annual tariff proposals. The ACCC notes that GasNet has proposed a complicated annual tariff adjustment mechanism which requires it to be satisfied that GasNet has complied with various formulae in schedule 4 of its proposed AA as well as to be satisfied that GasNet has provided best estimates of various parameters including CPI, pass through amounts, EDDs.

(vii) *Summary*

Having considered the code requirements the ACCC considers it would on the basis of information available have to make many changes to GasNet's proposed AA in relation to procedures for reference tariff variations. Instead, however, the ACCC would prefer to discuss this issue with GasNet between draft decision and final decision with a view to resolving some of the issues the ACCC has identified above and allowing GasNet to propose an alternative approach. Particularly, the ACCC will further discuss with GasNet between draft decision and final decision:

- linking procedures to ss. 8.3B–8.3H of the code

- timing of proposals and
- notice periods.

6.4 Reference tariff principles

6.4.1 Code requirements

Section 3.5 of the code requires the AA 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 s. 8 of the code.

Section 8.1 of the code states that a reference tariff and a reference tariff policy should be designed with a view to achieving the following objectives:

> 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 any of these objectives conflict in their application to a particular AA, the relevant regulator is to determine the manner in which they can best be reconciled or which of them should prevail by reference to the factors in s. 2.24 of the code. Section 2.24 of the code states:

> …In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:
>
> a. the Service Provider's legitimate business interests and investment in the Covered Pipeline;
>
> b. firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;
>
> c. the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;
>
> d. the economically efficient operation of the Covered Pipeline;
>
> e. the public interest, including the public interest in having competition in markets (whether or not in Australia);
>
> f. the interests of Users and Prospective Users;
>
> g. any other matters that the Relevant Regulator considers are relevant.

The Western Australia Supreme Court of Appeal decision provides guidance as to the appropriate application of ss. 8.1 and 2.24 of the code by the relevant regulator. The Court stated:

> …The last paragraph of s8.1 recognises that the objectives of (a) to (f) in s8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

Contrary to the submissions of the Regulator and Alinta, the discretionary task of seeking to reconcile conflicting objectives within s8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s8.1 itself. Of necessity, the Regulator must have guidance outside of s8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s8.1 the Regulator should take into account the factors in s2.24(a) to (g).[592]

In addition, s. 8.2 of the code stipulates that when approving a reference tariff and reference tariff policy, the relevant 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 the 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 in 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.

6.4.2 Assessment

The ACCC considers that GasNet has complied with the threshold issue in s. 3.5 of the code by providing a reference tariff policy in the revised AA.[593]

Each aspect of the reference tariff and reference tariff policy has been assessed in the relevant chapters of this draft decision. Where appropriate, the ACCC has proposed amendments considered to be necessary, and provided justification, for the proposed AA to be approved to satisfy the requirements of the relevant provisions of the code. The following discussion draws together the ACCC's conclusions on the compliance of the proposed reference tariff policy with the reference tariffs principles in ss. 8.1 and 8.2 of the code.

Where there is difficulty in approving a reference tariff policy and reference tariff structure, in the context of adhering to the principles in s. 8.1 of the code, the ACCC has determined which of these principles are to prevail, or the manner in which they are to be reconciled, having regard to the objectives of s. 2.24 of the code.

GasNet's reference tariff policy (including reference tariffs) appears in cl. 4 of its proposed AA and includes:

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592 *Re Michael; Ex parte Epic Energy* [2002] WASCA 231, [85].

593 This is considered in chapter 2 of this draft decision.

- transmission tariffs, incorporating:
    - a cost of service approach to revenue requirement (for capital and non-capital costs)
    - a volume-distance based method of cost allocation, including prudent discounts
    - a rate of return
- a tariff path
- provisions as to forecast new facilities investment
- a capital redundancy provision
- incentive mechanisms
- fixed principles and
- pass-through events.

The ACCC has considered these elements in the relevant chapters in this draft decision. The following provides an overall perspective of the compliance of GasNet's reference tariff policy and reference tariffs' with the principles in ss. 8.1 and 8.2 of the code.

6.4.2.1 Section 8.1 of the code

(i) *Recovery of efficient costs associated with the provision of reference services—s. 8.1(a) of the code*

Section 8.1(a) of the code provides that a reference tariff and a reference tariff policy should be designed to provide the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference service over the expected life of the assets used in delivering that service.

In assessing the recovery of efficient costs associated with the provision of reference services it is important to consider both the efficient costs of providing the reference services and the efficient recovery of these costs from users through the proposed reference tariffs.

In *Re Michael; Ex parte Epic Energy*, the Western Australian Supreme Court noted this objective does not necessarily set a ceiling or floor of the revenue that a service provider may earn.[594] Put another way, the objective is not to establish a revenue stream that recovers no more than the efficient costs or at least efficient costs. The ACCC notes that the Court took the view that 'legitimate' business interests are not limited to the recovery of normal profits or an economically efficient revenue stream. The ACCC considers this objective does not guarantee a right for a service provider to recover monopoly profits. Section 8.1(a) of the code, to the extent that it allows for the potential recovery of monopoly profits, must be weighed against the other objectives in s. 8.1 of the code. Where these objectives may conflict, the

[594] [2002] WASCA 231.

criteria in s. 2.24 of the code must instruct the relevant regulator's reconciliation. While regard must be had to each criterion in s. 2.24 of the code, it ultimately falls to the ACCC as the relevant regulator to decide how these objectives are to be reconciled.

The ACCC considers many of the proposed capital and non-capital costs are not unreasonable for a prudent service provider to incur. However, the ACCC has proposed a number of adjustments to GasNet's proposed capital and non-capital cost categories.[595]

Similarly, the ACCC has assessed GasNet's proposed rate of return and proposed amendments to the parameters based on different considerations as to the best estimate of forecasts and other relevant market conditions.[596] To ensure that only efficient costs are recovered, the ACCC has also proposed amendments to the GasNet's proposed cost allocation methodology which removes some tariffs from the price control formula.[597] Further, the ACCC's consideration of the capital redundancy policy and the fixed principles in respect of the carry-forward of allowable costs into the AA3 period has been assessed with a view to ensure GasNet is able to recover all of its efficient costs.[598]

The ACCC requires GasNet, in response to this draft decision, to account for costs and revenue from its role in issuing and administering AMDQ/credit certificates under the Market and System Operations Rules. The ACCC's proposed recognition of these costs and revenue will ensure that GasNet earns a stream of revenue that is more reflective of its efficient costs.

The ACCC considers that adoption of the proposed amendments set out in this draft decision provides GasNet with the opportunity to generate a revenue stream that recovers the efficient costs of providing the reference service, consistent with ss. 8.1(a) and 2.24(d) of the code.

(ii) *Replicating the outcome of a competitive market—s. 8.1(b) of the code*

The ACCC considers setting the regulated rate of return on 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.[599]

The ACCC also considers GasNet's proposed incentive mechanism allows for efficiency benefits to be shared between GasNet and users.[600] It also provides GasNet a constant incentive to reduce costs which would be expected in a competitive market.

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595 These proposals are detailed in chapters 3 and 5.1 of this draft decision.

596 These proposals are detailed in chapter 4 of this draft decision.

597 These proposals are detailed in chapter 6.3 of this draft decision.

598 This is detailed in chapters 3.4 and 6.1 of this draft decision.

599 This is detailed in chapter 4 of this draft decision.

600 This is detailed in chapter 7 of this draft decision.

Prices that reflect efficient costs are a feature of competitive markets. The ACCC has proposed amendments to ensure individual tariffs are reflective of efficient costs to the maximum extent practicable.[601]

The ACCC has considered GasNet's volumes, initial tariffs and proposed increases over the AA3 period and noted that GasNet's proposed increases in capital and non-capital costs for the period along with lower forecast volumes (in comparison to the AA2 period).[602] The ACCC considers that this necessarily must involve an initial tariff increase for the first year of the AA3 period and increased tariffs over the period. Whilst, large tariff increases may not normally be supportable in a competitive market (i.e. where real tariffs might be expected to remain constant or decline), reductions in real tariffs over the AA3 period have been unsustainable of the long-run level of real tariffs and GasNet should be able to have the opportunity to recover its efficient costs, which requires real tariff increases over the AA3 period.

The ACCC has proposed amendments to GasNet's price control formula to constrain GasNet from implementing larger increases above the CPI–X price path.[603] Specifically, the ACCC requires a ceiling of 2 per cent on its individual tariff control in its CPI–X+Y reference tariff control. This will limit the degree of increase within the period, which otherwise might distort investment decisions by users.

The ACCC considers that with the amendments proposed in this draft decision that tariffs are likely to be more consistent with those outcomes expected in a competitive market consistent with the objectives in s. 8.1(b) of the code.

(iii) *Ensuring the safe and reliable operation of the pipeline—s. 8.1(c) of the code*

The reference tariffs are based on cost forecasts as being necessary for the safe and reliable operation of the pipeline. Each review of the AA provides an opportunity for GasNet to increase its revenue, where necessary to ensure the safety and reliability of the pipeline. GasNet may also submit non scheduled revisions to the AA. Other factors that will tend to preserve the integrity of the system include:

- the contractual arrangements between GasNet and VENCorp to maintain the SEA
- GasNet's proposed tariff path based on a reference tariff control formula approach which allows GasNet to earn a revenue over the five year period which can not deviate outside 5.5 per cent bounds from its allowed costs[604] and
- accurate system planning (for which GasNet is assisted in this regard by the independent system planner, VENCorp).

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601 See chapter 6 of this draft decision.

602 See chapters 5.4 and 6.2 of this draft decision.

603 See chapter 6.3 of this draft decision.

604 ibid.

The ACCC considers that GasNet's proposals, with the amendments required by the ACCC pursuant to its assessment of capital and non-capital costs, will satisfy s. 8.1(c) of the code.

(iv) *Not distorting investment decisions—s. 8.1(d) of the code*

Efficient investment decisions upstream and downstream of the PTS will be facilitated by the transmission tariffs based on an allocation of costs to users which approximates the long run costs of providing the service. This is achieved by the adoption of tariffs which are consistent with ss. 8.38 to 8.43 of the code. The ACCC has proposed a number of amendments in relation to cost allocation in respect of GasNet's proposed tariffs.[605]

The ACCC has considered GasNet's proposed initial real average tariff increase and inclining real tariff path over the AA3 period.[606] The ACCC has considered the impact on investment decisions from GasNet's proposed initial real tariff increase for the first year of the period and increased tariffs over the period. The ACCC has proposed, however, amendments to GasNet's price control formula to constrain GasNet from implementing a Y greater than 2 per cent in its CPI–X+Y tariff control.[607]

For the AA3 period, GasNet has also proposed changes to prudent discounts applying to certain tariff zones introduced during the AA2 period.[608] The ability to use prudent discounts to manage bypass risk reduces the risk of inefficient investment by another service provider or user bypassing the PTS.

Efficient investment decisions for pipeline systems are also likely to follow if an appropriate rate of return is applied to the asset. The return should be neither excessively high so as to encourage over investment, nor so low as to discourage efficient investment in the pipeline. In addition, excessive returns and tariffs may discourage efficient investment in upstream and downstream markets. Conversely, inadequate returns and tariffs may encourage upstream and downstream over investment in the short term (but may lead to lower network investment levels in the longer term). The ACCC has assessed GasNet's rate of return and required some amendments to the parameters based on different considerations as to the best estimate of forecasts and other relevant market conditions.[609]

The return and tariffs should be considered in conjunction with other aspects of the AA to understand the full regulatory framework in which the business operates. In the case of GasNet, the amended redundant capital policy provision in the AA is unlikely to encourage over investment.[610] In addition, the extensions and expansions

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605 See chapter 6.1 of this draft decision.

606 See chapter 6.2 of this draft decision.

607 See chapter 6.3 of this draft decision.

608 See chapter 6.1 of this draft decision.

609 See chapter 4 of this draft decision.

610 See chapter 3.4 of this draft decision.

policy will provide GasNet with discretion regarding the coverage of extensions, giving GasNet flexibility to meet the needs of a growing market and an opportunity to earn returns greater than the benchmark nominated by the ACCC.[611]

The ACCC considers that with the required amendments in place, the AA will not have a tendency to distort investment decisions in upstream and downstream markets, in regard to the PTS in particular, and is consistent with the objectives in s. 8.1(d) of the code.

(v) *Efficiency in the level and structure of reference tariffs—s. 8.1(e) of the code*

A number of proposed amendments to GasNet's forecast costs have been made by the ACCC.[612] If these amendments are adopted, the ACCC considers that the level of tariffs, on average, will be more efficient. The ACCC has considered GasNet's initial average tariff and inclining average tariff path over the period and considers it generates an average price path, which is appropriate in the context of a low initial tariff base combined with lower forecast volumes and increased capital and non-capital costs over the AA3 period.[613]

The ACCC has assessed GasNet's proposed approach to the allocation and recovery of costs across individual users. The ACCC has required amendment to GasNet's cost allocation models such that allocation of costs to small and large users across zones will be more cost reflective and representative of small and large users' contribution to peak costs.[614] These changes have been designed to accord with the requirements in ss. 8.38–8.43 of the code.

The ACCC considers that with the required amendments to GasNet's proposals, the objective of s. 8.1(e) of the code is likely to be satisfied.

(vi) *Incentives to reduce costs and expand the market—s. 8.1(f) of the code*

GasNet's price control formula, encompassing some revenue exposure to potential changes in total demand, and the use of forecast costs, provides an incentive to GasNet to develop the market for gas and to achieve efficiencies in operations and maintenance and capital expenditure.

The ACCC considers that the rolling carryover approach for operation and maintenance costs will continue to provide GasNet with sufficient incentives to achieve efficiencies while ensuring that the benefits are passed on to users.

The ACCC considers with the required amendments in this draft decision, the objective in s. 8.1(f) of the code is likely to be satisfied.

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[611] See chapter 8.5 of this draft decision.

[612] See especially, chapters 3 and 5.1 of this draft decision.

[613] See chapter 6.2 of this draft decision.

[614] See chapters 5.2 and 6.1 of this draft decision.

6.4.2.2 Section 8.2 of the code

(i) ***Total revenue is established consistently with the principles and according to one of the methodologies contained in s. 8 of the code—s. 8.2(a) of the code***

Total revenue is to be determined by either the cost of service, IRR or NPV methods as set out under s. 8.4 of the code.

GasNet has adopted a cost of service approach[615] with the use of a reference tariff control formula approach and a trigger event adjustment approach to determine the movement of reference tariffs within the AA period.[616]

The ACCC considers that GasNet has satisfied s. 8.2(a) of the code.

(ii) ***The proportion of total revenue that any one reference tariff is designed to recover is calculated consistent with the principles of s. 8 of the code—s. 8.2(b) of the code***

The ACCC has considered the allocation of capital and non-capital costs and proposes GasNet to amend its allocation of direct costs such that costs are allocated on the basis of specific direct cost unit rates and not an average direct cost unit rate.[617]

With the adoption of the proposed amendments, the ACCC anticipates that s. 8.2(b) of the code will be satisfied.

(iii) ***The proportion of total revenue recovered from users of a service is calculated consistent with the principles of s. 8 of the code—s. 8.2(c) of the code***

As considered in chapter 6.1 of this draft decision, the ACCC's is concerned that GasNet's proposed cost allocation methodology:

- is less cost reflective than the maximum extent commercially and technically feasible
- replaces current zonal withdrawal tariffs for V users with a single postage stamp tariff and to levy its injection tariff on the whole winter period (June to September) rather than the top 10 peak days during this period and
- does not exclude tariffs from the price control formula where these tariffs should be excluded from the formula to prevent other users contributing to the recovery of those assets.

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615 Code, s. 8.4.

616 Code, s. 8.3.

617 See chapter 6.1 of this draft decision.

The ACCC has audited GasNet's models to ensure costs reflect an allocation of costs where tariff-D and tariff-V users are paying respective tariffs, which reflect their relative contribution to peak usage.[618]

The ACCC anticipates that if GasNet adopts the proposed amendments required that s. 8.2(c) of the code will be satisfied.

(iv) *Incentive mechanisms that are incorporated are consistent with the principles of s. 8 of the code—s. 8.2(d) of the code*

As considered in chapter 7.1 of this draft decision, the ACCC has required some amendment to GasNet's proposed incentive mechanism. The ACCC considers that if GasNet complies with these requirements, this aspect of the revised AA is likely to satisfy s. 8.2(d) of the code.

(v) *Forecasts are best estimates arrived at on a reasonable basis—s. 8.2(e) of the code*

The ACCC has specified amendments including:

- in chapter 4 to WACC parameters underlying the rate of return
- in chapters 3 and 5 to forecast capital and non-capital costs and
- in chapters 5.4, 6.3 to GasNet's GPG forecasts and TJ/EDD values.

With the ACCC's required amendments, the ACCC anticipates that s. 8.2(e) of the code will be satisfied.

6.4.3 Conclusion

The ACCC considers by GasNet adopting the amendments specified in this draft decision, the reference tariff and reference tariff policy will satisfy the factors in s. 8.2 of the code and be consistent with the objectives in s. 8.1 of the code, applied with reference to s. 2.24 of the code.

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618 See chapter 5.4 of this draft decision.

7 Performance and incentives

7.1 Incentive mechanisms

7.1.1 Code requirements

The code's general tariff principles provide that, where appropriate, the reference tariff should be designed to provide the service provider with the ability to earn greater profits (or less profits) than anticipated between AA periods if it outperforms (or underperforms) against the benchmarks that were applied in setting the reference tariff. The intention is that, to the extent possible, service providers be given a market-based incentive to improve efficiency and to promote efficient growth of the gas market (an incentive mechanism).

More specifically, s. 8.1(f) of the code refers to an incentive to reduce costs and to develop the market for reference and other services. Section 8.2(d) of the code allows an incentive mechanism to be incorporated into the reference tariff policy that the regulator is satisfied is appropriate and consistent with the objectives in s. 8 of the code. Section 8.4 of the code allows the service provider to retain some or all of the benefits arising from efficiency gains under an incentive mechanism.

In addition to these broad provisions, the code sets out some particular guidance on the use of incentive mechanisms. Section 8.44 of the code provides that the reference tariff policy should, wherever the regulator considers it appropriate, contain an incentive mechanism that provides the service provider with an opportunity to retain a share of returns arising from the sale of the reference service. This should particularly be the case where the additional returns can be attributed, at least in part, to the actions of the service provider.

In accordance with s. 8.45 of the code:

> [a]n incentive mechanism may include (but is not limited to) the following:
>
> (a) specifying the Reference Tariff that will apply during each year of the Access Arrangement Period based on forecasts of all relevant variables (and which may assume that the Service Provider can achieve defined efficiency gains) regardless of the realised values for those variables ;
>
> (b) specifying a target for revenue from the sale of all Services provided by means of the Covered Pipeline, and specifying that a certain proportion of any revenue received in excess of that target be retained by the Service Provider and that the remainder must be used to reduce the Tariffs for all Services provided by means of the Covered Pipeline (or to provide a rebate to Users of the Covered Pipeline); and
>
> (c) a rebate mechanism for Rebatable Services pursuant to section 8.40 [of the code] that provides for less than a full rebate of revenues from the Rebatable Services to the Users of the Reference Service.

Section 8.46 of the code sets out the following objectives for an incentive mechanism:

(a) to provide the Service Provider with an incentive to increase the volume of sales of all Services, but to avoid providing an artificial incentive to favour the sale of one Service over another;

(b) to provide the Service Provider with an incentive to minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services;

(c) to provide the Service Provider with an incentive to develop new Services in response to the needs of the market for Services;

(d) to provide the Service Provider with an incentive to undertake only prudent New Facilities Investment and to incur only prudent Non Capital Costs, and for this incentive to be taken into account when determining the prudence of New Facilities Investment and Non Capital Costs for the purposes of section 8.16(a) and 8.37 [of the code]; and

(e) to ensure that Users and Prospective Users gain from increased efficiency, innovation and volume of sales (but not necessarily in the Access Arrangement Period during which such increased efficiency, innovation or volume of sales occur).

7.1.2 Current access arrangement provisions

Provisions relating to incentive mechanisms for the PTS are currently stipulated in cl. 4.7 of GasNet's second AA. The provisions provide:

- the price path for transmission tariffs are not to be adjusted for subsequent events, except in accordance with cls. 4.4 (new facilities investment that satisfies s. 8.16 of the code), 4.5 (new facilities investment that does not satisfy s. 8.16 of the code) and 4.9 (pass-through events) of GasNet's second AA and
- a rolling carryover incentive mechanism that permits GasNet to retain efficiency gains (losses) from the AA2 period in the AA3 period (the benefit sharing allowance as detailed in cl. 7.2 of the second AA).

7.1.2.1 The benefit sharing allowance

The fixed principle in cl. 7.2 of GasNet's second AA provides for a benefit sharing allowance (B_t) to be calculated in each of the five years following 2007. The B_t in each year is equal to the sum of the efficiency gains or losses (E_t) in selected prior years, in accordance with table 7.1.1:

Table 7.1.1: Efficiency benefit sharing scheme

Year	B_t
2008	$E_{2003} + E_{2004} + E_{2005} + E_{2006}$
2009	$E_{2004} + E_{2005} + E_{2006}$
2010	$E_{2005} + E_{2006}$
2011	E_{2006}
2012	-

The E_t over the AA2 period are calculated in the manner detailed in table 7.1.2.

Table 7.1.2: Efficiency gains or losses—AA2

Year	E_t
2003	$F_{2003} - A_{2003}$
2004–06	$E_t = (A_{t-1} - A_t) - (F_{t-1} - F_t)$
2007	

where A_t and F_t are the actual and forecast operating and maintenance costs for year t.

7.1.3 Proposal

7.1.3.1 Revisions to fixed principles[619]

GasNet proposes to amend the fixed principle in cl. 7.2 that will affect the carryover of allowances to apply in the AA4 period. GasNet proposes to remove fuel gas costs from forecast and actual operating and maintenance costs on the basis that these costs are uncontrollable and are therefore inconsistent with the intention of the mechanism.[620] GasNet's proposed incentive mechanism no longer includes revenues from refill tariffs (which are intended to reflect fuel gas costs) in calculating its forecast operating costs.

GasNet also proposes to insert a provision requiring the regulator to consider, taking into account the requirements of the code, whether and to what extent negative allowance amounts (i.e. negative amounts of B_t as described in the previous section) should affect revenues in AA4. The current provision requires the regulator to apply the calculated amounts without the use of discretion. GasNet's justifications for requiring this discretion are:

- the concern expressed by the ACCC, in approving the existing mechanism, overstates the ability of companies to alter the timing of their opex profiles
- if GasNet incurs higher cost while still being a prudent and efficient service provider, the expenditure allowance in the subsequent access period will be inappropriately reduced below its efficient level, which is inconsistent with s. 8.1(a) of the code
- other regulators have acknowledged that there may be circumstances in which negative carryover amounts could affect the entity's ability to provide efficient services and
- the use of discretion in applying negative carryover amounts, exercised in accordance with the code, is consistent with the approach used by the ESC and ESCOSA.[621]

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619 Section 8.47 of the code provides that the reference tariff policy may provide that certain principles are fixed for a specified period and are not subject to change when a service provider submits reviews to an access arrangement without agreement of the service provider.

620 GasNet, *Proposed Access Arrangement Submission 2008–12*, 24 May 2007, p. 108.

621 ibid.

While not addressed in its submission, GasNet proposes a related amendment to require the relevant regulator to, amongst other things, 'use' actual operating costs in 2011 as a basis for setting expenditure benchmarks for the AA4 period, rather than 'take into account' these costs as per the current provision.

7.1.4 Submissions

No submissions were received on this aspect of the proposed AA.

7.1.5 Assessment

7.1.5.1 Removal of fuel gas costs

The ACCC considers that GasNet's proposal to exclude the cost of fuel gas and revenues from refill tariffs from the benefit sharing calculation is appropriate as these are largely uncontrollable. For clarity, GasNet's amendments should state that fuel gas costs arising from refill tariffs should also be excluded.

7.1.5.2 Negative carryovers and use of base year expenditure

GasNet's proposed treatment of negative carryover amounts and the reference to a 'base year' expenditure are fundamental to the operation of the incentive mechanism. The ACCC considers that GasNet's current incentive mechanism has particular features that justify the automatic application of negative carryover amounts and therefore does not accept the proposed revisions. The application of negative carryover amounts and related issues have been considered recently by several regulators, most notably the ESC, ESCOSA and the AER. The ACCC's consideration of their particular carryover mechanisms and that proposed by GasNet is outlined below.

In its current review of the Victorian gas distribution arrangements, the ESC noted that Envestra's negative carryover amount arose due to an increase in expenditure in 2006, which formed the basis for determining benchmarks for the next access period.[622] Given that Envestra had underspent with respect to benchmarks in the prior years, the ESC expressed a concern that expenditure in the base year could have been inflated to Envestra's advantage. In order to preserve the integrity of the mechanism, the ESC applied the resulting negative carryover amount. In consultation prior to this review, the ESC reaffirmed its position that negative carryover amounts were allowable under the code, although maintained that it would consider the code requirements (including ss. 2.24 and 8.1 of the code) in assessing the application of negative carryover amounts.[623] The incentive mechanism approved by the ESC involves an ex post adjustment to expenditure benchmarks to account for uncontrollable cost variations arising through customer connections. This is similar

[622] Essential Services Commission, *Gas Access Arrangement Review 2008-2012: Draft Decision*, 28 August 2007, p. 519.

[623] id., *Gas Access Arrangement Review 2008-2012: Consultation Paper No. 2*, October 2006, p. 124.

to its approach in electricity distribution, which is based on general demand growth and partial factor productivity measures.[624]

In its 2006 review of gas distribution arrangements, ESCOSA commented that the symmetrical treatment of negative and positive carryover amounts is required for an effective continuous incentive.[625] It stated that, in the absence of negative carryover amounts, a service provider may face an incentive to artificially increase its costs towards the end of an access period when these form the basis of setting allowances for the next period.[626] It further considered that negative amounts were consistent with ss. 8.1(b), 8.1(d), 8.1(e) and 8.1(f) of the code.[627] The incentive arrangements approved by ESCOSA do not involve adjustments to expenditure benchmarks for uncontrollable or unforeseen events when calculating carryover amounts. ESCOSA noted that the risk of such events resulting in windfall gains or losses through the carryover mechanism was expected to be symmetric.

The AER considered that negative carryover amounts did not contravene a National Electricity Law requirement to provide a reasonable opportunity for service providers to recover efficient costs, which mirrors s. 8.1(a) of the code.[628] The AER noted that service providers may face an incentive to inflate actual expenditures in order to increase benchmarks in the subsequent period, although any gains from doing so would be offset by the penalties arising through the application of negative carryover amounts. Its guideline for electricity transmission businesses will automatically apply negative carryover amounts while providing the AER a general discretion to consider adjustments to benchmarks for changes in costs related to demand growth, pass-through events, capitalisation policies and other events nominated by the service provider. These adjustments are designed to reduce the risk of negative carryover amounts arising from uncontrollable events.[629]

From the considerations of these regulators, the ACCC notes the following:

- each considers that the application of negative carryover amounts does not circumscribe the opportunity of the service provider to recover efficient costs
- each regulator has expressed a concern that, where the actual expenditure of a particular year forms the basis of forecasts for the next access period, there is an incentive for a service provider to inflate expenditure in that year

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[624] id., *Electricity Distribution Price Review 2006-10: Final Decision Volume 1*, February 2006, pp. 435 and 436.

[625] Essential Services Commission of South Australia, *Proposed Revisions to the Access Arrangement for the South Australian Gas Distribution System: Final Decision*, June 2006. p. 202.

[626] ibid., p. 203.

[627] ibid.

[628] Australian Energy Regulator, *Final Decision: Electricity transmission network service providers Efficiency benefit sharing scheme*, September 2007, p. 8.

[629] ibid., p. 9.

- the application of negative carryover amounts to intended to precisely offset this incentive; and
- there is a risk of windfall gains and losses arising through the carryover mechanism due to uncontrollable factors which may warrant the adjustment of expenditure benchmarks or use of discretion in applying carryover amounts.

The ACCC notes that GasNet's proposed removal of fuel gas costs, in addition to the existing adjustments for expenditure associated with unforeseen network extensions and expansions, significantly reduces the risk of a legitimate and unforeseen cost increase resulting in a negative carryover amount.

In comparison to the incentive mechanisms approved by the ESC, ESCOSA and the AER, GasNet's provisions place a considerable weight on using a base year of expenditure in assessing forecasts for the subsequent period. For example, the ESC's use of a base year to set expenditures for the access period commencing in 2008 was only indicated as a preferred approach (and subject to several qualifications) in 2006.[630] ESCOSA's approach to setting opex benchmarks did not involve any prior commitment or explicit requirement to use a base year or any historical expenditure. By contrast, the incentive mechanism that applied to GasNet over the AA2 period was based on a requirement for the regulator to take into account actual expenditure in 2006 as a fixed principle, and was set at the beginning of the access period. The greater emphasis placed on the base year expenditure would increase the prospect of gains by spending more in that year, reinforcing the need to apply negative carryover amounts to maintain the incentive to minimise costs in each year in accordance with ss. 8.1(f) and 8.46(b) of the code.

GasNet has proposed a further amendment to bind the regulator to using base year expenditures to set benchmarks although has not sought to justify this amendment. The ACCC considers that the operation of the proposed cl. 7.2(h) may be unworkable in practice as it requires the regulator to also comply with the general code requirements. Specifically, the regulator may be compelled to make adjustments to the base year expenditure to correct for obvious anomalies to ensure that benchmarks represented the efficient level of costs.

Finally, the ACCC notes that GasNet has not expressed any concern with penalties that arose out of the incentive mechanism over the AA2 period, nor suggested that such penalties are inconsistent with s. 8.1(a) of the code. The ACCC considers that the incentive mechanism used for the AA2 period was effective and in accordance with ss. 8.1(f) and 8.46 of the code. The introduction of discretion in applying negative carryover amounts would reduce the certainty and effectiveness of the mechanism without any corresponding benefits in terms of GasNet's legitimate business interests. Accordingly, with the exception of the removal of fuel gas costs, the ACCC does not accept GasNet's proposed revisions.

[630] Essential Services Commission, *Consultation Paper No. 2*, op. cit., p. 71.

Proposed amendment 29

Before the proposed revised access arrangement can be approved, GasNet must

- remove cl. 7.2(i) of the proposed revised access arrangement and
- replace ‘use’ with ‘take into account’ in cl. 7.2(h)(ii) of the proposed revised access arrangement.

7.2 Key performance indicators

7.2.1 Code requirements

The code requires service providers to disclose key performance indicators (KPIs). Category 6 of attachment A of the code lists the following relevant items:

- industry KPIs used by the service provider to justify ‘reasonably incurred’ costs and
- the service provider’s KPIs for each pricing zone, service or category of asset.

7.2.2 Current access arrangement provisions

GasNet’s second AAI contains the following KPIs:

- operating costs/GJ of gas delivered
- operating costs as a percentage of capital investment
- operations and maintenance costs per metre of pipeline
- general and administration costs/GJ of gas delivered
- operations and maintenance costs as a percentage of capital investment and
- operating costs per TJ/km.

GasNet also submitted a benchmarking report from consultants Cap Gemini. That report included the following KPIs:

- general and administration expenses per million cubic metres delivered
- measurement and pipeline expenses per km of pipeline and
- compression expenses per million cubic metres/kms (excluding fuel).

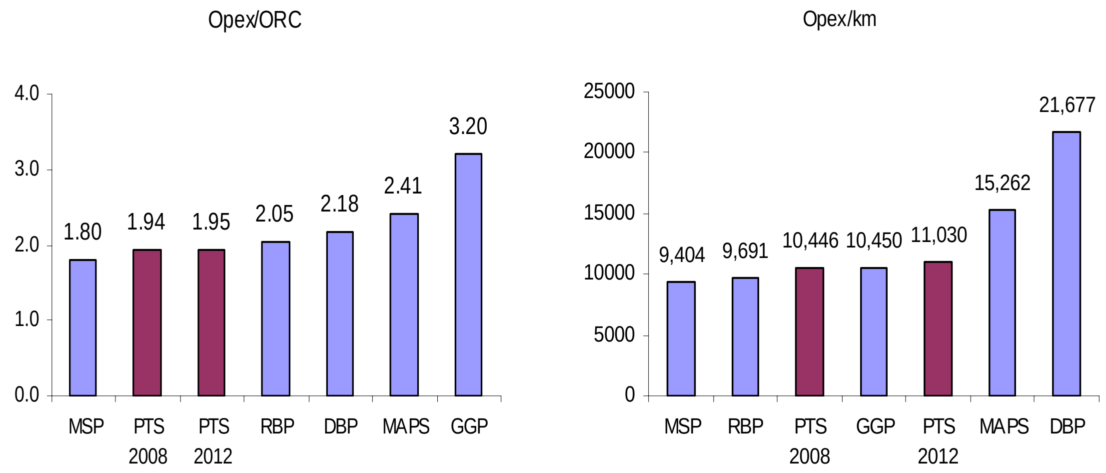
7.2.3 Proposal

GasNet has submitted only two KPIs:

- operating costs as a percentage of the optimised replacement costs and
- operating costs per km.

The results of the comparison between GasNet’s performance and that of a sample of other pipelines are shown in figure 7.2.1. GasNet submitted that the KPIs indicate that GasNet is in the middle of the range of the pipelines in the sample.

Figure 7.2.1: GasNet's comparative KPIs



Source: GasNet, *Submission 2008–12*, p. 115; GasNet, *Proposed AAI*, p. 13.
Notes: Fuel gas is excluded from the operating cost.

The results for these pipelines (other than GasNet) were adopted from the ACCC's 2006 final decision for the RBP access arrangement. GasNet adopted this particular sample of companies because, according to GasNet, data for other pipelines is not available or is dated.

In providing only two KPIs GasNet comments that many measures used previously involved indicators that were not within the immediate control of management. GasNet considers that the code requirement to justify reasonably incurred costs is intended to refer to only those costs that are within management's control.

GasNet submits that measures that utilise throughput and capacity are invalid because they are only weakly related to operating costs. GasNet stated that it is now more common for owners of pipelines to report operating costs on the basis of length of pipeline and capital costs (at replacement cost).

7.2.4 Submissions

In terms of the 'opex per km' indicator, Origin Energy did not consider it acceptable for GasNet to lie in the middle of the range. Origin Energy submitted that:

> Given the relatively small geographic size and quality of the PTS itself (for instance gas losses on the PTS are very low) it would be reasonable to expect that GasNet would be near the top of the 'opex per km' measure.[631]

7.2.5 Assessment

In previous decisions on the AAs for various pipelines the ACCC has commented on the limitations of KPIs. Different characteristics among pipelines make direct comparisons problematic. The PTS is a market carriage system (other regulated pipelines are contract carriage) and VENCorp performs the system control function,

[631] Origin Energy, *Submission to the issues paper*, 9 July 2007, p. 9.

which the pipeline owner would normally undertake. To allow for this in the analysis GasNet has added $700 000[632] of VENCorp's costs to its own operating costs.

The two ratios submitted by GasNet are the same that were submitted by Australian Pipeline Trust Petroleum Pipelines Limited (APTPPL), the owner of the Roma to Brisbane pipeline (RBP), to the ACCC in relation to the 2006 RBP AA. In that matter APTPPL relied on a report from Infrastructure and Regulation Services Pty Ltd (IRS).[633] IRS argued that indicators based on other parameters such as throughput, total capacity and utilised capacity were of little use as indicators of efficiency as these were not drivers of operating costs. The ACCC agrees with this argument. For similar reasons GasNet has omitted on this occasion many of the indicators that it submitted to the ACCC for the second AA.

While GasNet's analysis suggests that it is performing well in relation to other pipelines, it cannot be concluded that all of the cost items within GasNet's non-capital costs are consistent with the code. If this were the case a clearly excessive cost item would be accepted as reasonable as long as the total costs were not high in comparison to the other pipelines in the benchmarking exercise. Despite the limitations of KPIs the ACCC considers that they are a useful tool as a broad indicator of comparative efficiency. Nevertheless, they are not a substitute for a detailed assessment of costs on a case-by-case basis. For reasons outlined in chapter 4 of this draft decision, the ACCC proposes to reduce a number of GasNet's forecast costs.

Substituting the ACCC's proposed costs for GasNet's produces the ratios shown in figure 7.2.2.[634]

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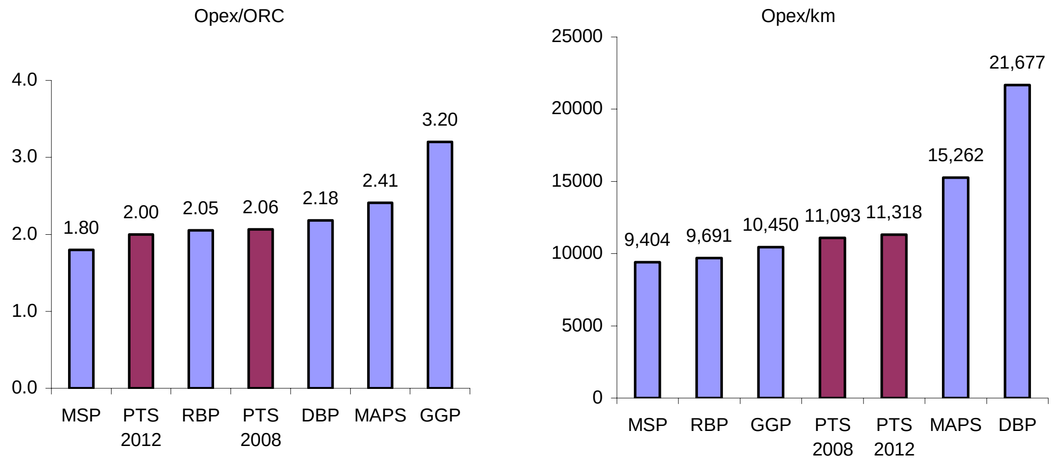
632 The equivalent figure during the AA2 period was $620 000, which the ACCC accepted as reasonable.

633 Infrastructure and Regulation Services, *Non-capital costs benchmarking for the Roma-Brisbane Pipeline*, January 2006.

634 GasNet notes the statistics (in Figure 1.4.1) were taken from data published in various access arrangements over the years 2004 to 2006. To enable GasNet to be compared to other pipelines, GasNet deflated its value for ORC by the CPI to reduce it to 2006 dollars. The ACCC understands, however, that pipeline costs have been increasing at a rate greater than the CPI. This implies the value of ORC may be overstated and the ratio opex/ORC may be accordingly understated. Nevertheless, for the purpose of this exercise the difference is not likely to be significant.

Figure 7.2.2: KPIs based on ACCC's proposed operating costs



In terms of the opex/km ratio, GasNet still falls in the middle of the sample of pipelines. In relation to the opex/ORC ratio, however, the result for GasNet shifts from the middle towards the lower end of the scale. GasNet's performance is now comparable to the APA Group's other assets, the RBP and the MSP.

8 Non-tariff elements

This chapter considers the non-tariff elements of GasNet's proposed access arrangement (AA). Non-tariff elements, among other things, refer to a policy on the trading of capacity, queuing for spare and developable capacity as well as terms and conditions.

The code sets out the minimum elements that must be included in an AA as well as principles for establishing the reference service and the other elements and policies to be set out in the AA. It should be acknowledged however, that service providers and their customers may agree to different or more detailed arrangements in their gas haulage contracts. The ACCC's role is to ensure that proposed terms and conditions of the AA are reasonable and do not prevent the efficient provision of the pipeline's services.

The day to day operation of the pipeline is also subject to technical regulation which ensures the safe operation of the pipeline.

8.1 Services policy

8.1.1 Code requirements

The code requires an AA to contain a services policy regarding the services to be offered by a service provider (the services policy). Section 3.2 of the code requires the services policy to 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.

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.

8.1.2 Current access arrangement provisions

Clauses 3.1, 3.2 and 3.3 of the second AA states that GasNet will make the tariffed transmission service available to VENCorp at the reference tariffs, on the terms and conditions in accordance with those set out in the service envelope agreement (SEA) and the Market and System Operations Rules (MSO rules).

8.1.3 Proposal

GasNet proposes to retain its existing services policy in cl. 3.2 for its proposed AA.

GasNet states that:

> (a) As the PTS is a Market Carriage transmission system, Users and Prospective Users of the PTS are offered one Reference Service (or bundle of Reference Services), being the transportation of gas in accordance with the MSO rules;
>
> (b) VENCorp, as operator of the PTS under the MSO rules, is responsible for the provision of the Reference Service;
>
> (c) Although it is a Service Provider under the Code, GasNet does not, under the MSO rules, provide gas transmission Services directly to Users;
>
> (d) For the purposes of Reference Tariff calculation, the Reference Service comprises two components:
>
> > (i) the VENCorp services, which VENCorp provides itself (these are dealt with in the VENCorp access arrangement); and
> >
> > (ii) the tariffed Transmission Service, being the benefit of the availability of the PTS (which is dealt with in GasNet Access Arrangement).

8.1.4 Submissions

TRUenergy states that given the lack of public information regarding the Victorian Government plans for VENCorp's AA, the general approach adopted by GasNet in respect of its services policy for AA3 is an acceptable working assumption. TRUenergy requests that the ACCC confirm with the Victorian Government their intentions regarding AAs for VENCorp and assumes that the operational interfaces between VENCorp and GasNet will be unchanged. TRUenergy also comments that the updated SEA between VENCorp and GasNet has not addressed commercial aspects of the contract and market participants have not had an opportunity to provide input into the commercial aspects of the SEA for the wider market.[635]

8.1.5 Assessment

Under s. 10.1 of the code, VENCorp is required to submit a revised AA as the operator of the PTS. However, the Victorian Government has advised that the obligation for VENCorp to submit an AA will be removed. GasNet submits that the proposed changes will have a significant impact on the existing legislative framework as GasNet has to submit its revised AA on the basis that there are two service providers with respect to the PTS:

- GasNet being the owner of the PTS and responsible for the maintenance of the PTS and
- VENCorp, being the operator of the PTS under the market-carriage regime established by the MSO rules.[636]

GasNet states that the proposed changes to VENCorp will impact on the existing arrangements between GasNet and VENCorp, and the existing arrangements with users of the PTS. Given this uncertainty, GasNet submits that it reserves the right to withdraw and resubmit on any impacted elements of its (draft) revised AA in the event that the anticipated changes are made to the existing role of VENCorp.[637] GasNet has therefore not as yet made modifications to its services policy to reflect the proposed new arrangements.

GasNet proposes a services policy on the basis that the status quo remains in terms of the arrangements between GasNet, VENCorp and users. The Victorian Government is in the process of amending the relevant legislative provisions to remove VENCorp's obligation to submit a revised AA under the code. As a consequence, users will be required to enter into bilateral contracts for the gas transportation service with GasNet instead of VENCorp. Under these new arrangements, GasNet will provide gas transportation services directly to users as well as making the PTS available to VENCorp as required by the SEA.

As a result of these changes, GasNet anticipates that it may need to:

- develop a transmission system use of system agreement with users and
- re-negotiate aspects of the SEA with VENCorp.[638]

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635 TRUenergy, *Submission to the issues paper*, 27 June 2007, p. 3.

636 GasNet, *Proposed access arrangement submission 2008–12*, 24 May 2007, p. 8.

637 ibid., p. 8.

638 GasNet, *Email to the AER*, 18 May 2007.

Hence, GasNet's proposed services policy for AA3 will not reflect the relationship between VENCorp and GasNet as proposed by the Victorian Government.

The ACCC requires GasNet to revise its services policy to reflect that GasNet rather than VENCorp has the direct legal relationship with users, and will provide gas transportation services directly to users.

The ACCC has considered TRUenergy's comments regarding the lack of consultation on the commercial arrangements in the recently renegotiated SEA. The ACCC's conclusions on the commercial arrangements in the SEA are considered in chapter 8.1 of this draft decision.

Proposed amendment 30

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.2 of the proposed revised access arrangement to reflect that GasNet will provide gas transportation services directly to users.

8.2 Terms and conditions

8.2.1 Code requirements

Section 3.6 of the code requires an AA to include the terms and conditions on which a service provider will supply each reference service. These terms and conditions must, in the regulator's opinion, be reasonable. In assessing whether the proposed revised terms and conditions are reasonable, the relevant regulator is guided by s. 2.24 of the code.

8.2.2 Current access arrangement provisions

The current provisions of GasNet's second AA state that the terms and conditions on which GasNet will supply the tariffed transmission service are the same as those set out in the SEA and the MSO rules.

As outlined in GasNet's revised AA submission, GasNet and VENCorp are parties to the SEA. The terms of the SEA are:

GasNet agrees to:

(i) make available the entire PTS to VENCorp and

(ii) provide a range of supporting services to VENCorp.

VENCorp agrees to:

(i) operate the PTS in accordance with the MSO rules and

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

The effect of the SEA is that VENCorp has the operational control over the PTS. GasNet and VENCorp have extended the SEA to 31 December 2012 which coincides with the conclusion of the AA3 period.[639]

8.2.3 Proposal

GasNet has recently updated the SEA to apply until the end of the AA3 period on 31 December 2012 and proposes to make the SEA publicly available.[640]

The ACCC understands that as VENCorp will not be required to submit an AA for approval, users will be required to enter into gas transportation eeds (GTD) with GasNet. GTDs include the terms and conditions of access to the transportation service which will provide a direct legal relationship between GasNet and users of the transportation service.

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639 ibid., p. 12.

640 GasNet and VENCorp, *Joint letter to the ACCC*, 18 January 2007.

8.2.4 Submissions

TRUenergy comments that given the limited time before the commencement of the third AA and the paucity of information that has been available to date, it is disturbing that use of system agreement negotiations between GasNet and VENCorp have not started. TRUenergy seeks the ACCC's advice regarding the expected timeline for use of system negotiations and the process that is envisaged between GasNet, the ACCC and users.

TRUenergy also submits that a key commercial component of the SEA is GasNet's liability cap in instances where the transmission pipeline owner fails to provide the contracted pipeline capacity to the market. TRUenergy notes that the total liability amount was struck at $1 m for a calendar year in the 1999 version of the SEA and remains at $1 m in the amended SEA between VENCorp and GasNet agreed in January 2007. TRUenergy submits that as the liability amount remains the same, GasNet has enjoyed a liability discount for the intervening eight years that approximates 25 per cent. TRUenergy maintains that market participant risk from GasNet related costs will progressively increase in each of the five years of AA3, and therefore suggests that GasNet's liability cap in the SEA contain a CPI escalation facility with a CPI base of 1999.[641]

8.2.5 Assessment

Under the SEA, VENCorp agrees that GasNet be paid directly by users for the transmission service. VENCorp also has GTDs with users, which requires users to pay GasNet directly for the gas transportation service. However, these GTDs will expire in December 2007. GasNet will need to include revised GTDs (or use of system agreements) in its revised AA, given that it is anticipated that VENCorp will no longer be required to have GTDs with users. The ACCC agrees with TRUenergy that there is limited time for revised agreements to be negotiated before the commencement of GasNet's revised AA. The ACCC notes that the Victorian Government has introduced the *Energy Legislation Further Amendment Bill 2007* into Parliament to amend the *Gas Pipelines Access (Victoria) Act 1998* to remove VENCorp as a service provider under the gas access regime. This Bill also provides for amendments to the *Gas Industry Act 2001* and the MSO rules to require the ACCC and the AER to approve VENCorp's fees for operating the PTS.

The ACCC notes that the Victorian Government's proposal to require GasNet to enter into bilateral contracts with users may require amendments to the SEA. As a consequence, it is likely that the SEA will need to be updated to reflect these arrangements where GasNet provides the transportation service directly to users. GasNet will also need to provide GTDs for users, which specified the terms and conditions on which the transportation service will be provided.

The ACCC understands that GasNet proposes to include interim GTDs as part of its proposed AA, which will commence in January 2008 and expire in June 2008. The ACCC also understands that GasNet will re-negotiate long term GTDs with users, to

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641 TRUenergy, op. cit., p. 3.

take effect from July 2008. As these revised GTDs will form part of the terms and conditions under which GasNet will supply the reference service, the relevant regulator will need to approve these GTDs. To enable these revised GTDs to be assessed and approved, the ACCC proposes that GasNet include a trigger event for a revision of the AA in accordance with s. 3.17(b)(ii) of the code, where the trigger event would be a submission of revised GTDs to the relevant regulator for approval.

Accordingly, the ACCC requires GasNet as part of its AA to include GTDs[642] and will review GasNet's interim GTDs prior to the final decision. Further, the ACCC proposes that GasNet should consider including a trigger event in its AA as a result of re-negotiating GTDs with users during the AA period. Alternatively, GasNet may seek revisions to its AA.

TRUenergy's comments in relation to GasNet's liability cap in the SEA are considered in the context of GasNet's proposed self insurance allowance in chapter 5.1 of this draft decision.

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[642] In accordance with s. 3.6 of the code.

8.3 Capacity management policy

8.3.1 Code requirements

Section 3.7 of the code requires an AA to include a statement that the covered pipeline is to operate under either a contract carriage capacity management system or a market carriage capacity management system. If the pipeline is to operate as a market carriage pipeline then consent from the relevant minister must be obtained and provided to the relevant regulator and a trading policy is not required.

8.3.2 Current access arrangement provisions

Clause 8.1 of the GasNet's second AA states that the PTS is a market carriage pipeline. Accordingly, it does not include a trading policy which is not required under the code if the pipeline is to operate as a market carriage system as noted above.

8.3.3 Proposal

Clause 8.1 of the proposed revised AA states that the PTS is a market carriage pipeline. GasNet notes that s. 3.9 of the code requires an AA that is described as a contract carriage pipeline must include a trading policy. However, as the PTS will continue to be a market carriage pipeline, s. 3.9 of the code does not apply.[643]

8.3.4 Submissions

No submissions were received on this aspect of the proposed AA.

8.3.5 Assessment

The ACCC considers that the Victorian Minister provided ongoing consent to this capacity management policy, whilst the NSW Minister provided consent for the duration of the existing access arrangement period.[644]

To approve the PTS as a market carriage pipeline, the ACCC requires the consent of that portion of the PTS covered by the NSW Minister pursuant to s. 3.8 of the code. VENCorp subsequently sought consent from the NSW Minister on behalf of GasNet to enable the application of the market carriage system to the NSW section of the Interconnect.[645] Pursuant to s. 3.8 of the code, the NSW Minister provided consent to the ACCC for a market carriage capacity management system to apply to the portion of the Interconnect which forms part of the PTS located in NSW for the duration of the AA3 period.[646]

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643 GasNet, *Submission*, op. cit., p. 111.

644 New South Wales Minister for Energy, *Letter to the Victorian Energy Networks Corporation*, 7 March 2002.

645 id., *Letter to the Victorian Energy Networks Corporation*, 29 August 2007.

646 id., *Letter to the ACCC*, 25 October 2007.

The ACCC proposes to accept that the current capacity management policy of market carriage continues to apply to the PTS.

8.4 Queuing policy

8.4.1 Code requirements

Pursuant to ss. 3.12 to 3.15 of the code, an AA 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 seeking dispute resolution under s. 6 of the code.

8.4.2 Current access arrangement provisions

The responsibility for establishing a queuing policy for the PTS is currently allocated to VENCorp under cl. 8.2 of the AA.

8.4.3 Proposal

Clause 8.2 of GasNet's proposed revised AA states that consistent with s. 10.2 of the code, responsibility for complying with the obligations imposed by ss. 3.12 to 3.15 of the code is allocated to VENCorp.

8.4.4 Submissions

No submissions were received on this aspect of the proposed AA.

8.4.5 Assessment

VENCorp is responsible for the queuing policy for the PTS in accordance with s. 5.3 of the MSO rules. The ACCC notes that the Victorian Government will amend the *Gas Industry Act 2001* (Vic) such that VENCorp is no longer required to submit an AA under the national gas access regime. The ACCC understands that notwithstanding VENCorp's requirement not to submit an AA, VENCorp will continue to have responsibility for a queuing policy for the PTS as specified in the MSO rules.

However, to avoid ambiguity as to the responsibility for a queuing policy, the ACCC requires GasNet to amend its proposed revised AA to refer to VENCorp's responsibility to provide a queuing policy in accordance with s. 5.7 of the MSO rules.

Proposed amendment 31

Before the proposed revised access arrangement can be approved, GasNet must:

- amend cl. 8.2 of the proposed revised access arrangement to be consistent with s. 5.7 of the MSO rules and
- to reflect that the responsibility for complying with the obligations imposed under ss. 3.12–3.15 of the code is allocated to VENCorp.

8.5 Extensions and expansions policy

8.5.1 Code requirements

Section 3.16 of the code requires an AA to have an extensions and expansions policy. The policy must set out the method to determine whether any extension to or expansion of the system's capacity will be treated as part of the covered pipeline. A service provider is also required to specify the effect on the reference tariff if an extension or expansion is treated as part of the covered pipeline. If the service provider agrees to fund new facilities if certain conditions are met, the extensions and expansions policy must outline the conditions under which the service provider will fund those new facilities and provide a description of those new facilities.

8.5.2 Current access arrangement provisions

8.5.2.1 Coverage

Under the current provisions of GasNet's AA, all expansions of the PTS are covered. Extensions, however, will not be covered if prior to the extension coming into service, GasNet gives written notice to the ACCC that it will not be covered.

8.5.2.2 Effect of extensions/expansions on reference tariffs

The effect of GasNet's extensions and expansions policy on reference tariffs is summarised below:

- GasNet may in accordance with cls. 4.4 and 4.5 of the proposed AA, submit revisions to its AA under s. 2.28 of the code, seeking to increase the capital base of the PTS to recognise the actual capital costs incurred, which is not included as forecast new facilities investment for the AA period and
- AA revisions will be considered under the relevant provisions of the code and as allowed by the code, this may result in an increase of the capital base to reflect actual capital costs or a recoverable portion if the new facilities investment does not satisfy s. 8.16 of the code.

8.5.3 Proposal

8.5.3.1 Coverage

As for AA2, GasNet proposes that extensions will not be covered if prior to the extension coming into service, GasNet gives written notice to the ACCC that it will not be covered. However, GasNet proposes a change for AA3 in relation to expansions whereby instead of all expansions being covered there will be one exception:

> If it is an expansion required to increase withdrawals at Culcairn over and above the current capacity of 17 TJ/day and GasNet gives written notice to the Regulator before the expansion comes into service that the expansion will not be covered.

GasNet submits this proposed non coverage for expansions at Culcairn is on the basis of effective competition between the Interconnect pipeline and the Eastern Gas pipeline (EGP), which it argues prevents the exercise of market power and the necessity to regulate these tariffs.[647]

8.5.3.2 Effect of extensions or expansions on the reference tariff

GasNet proposes no changes to its policy on how extensions and expansion will affect reference tariffs for AA3.

8.5.4 Submissions

8.5.4.1 Expansions

In support of GasNet's proposal, TRUenergy submits that whilst it is unable to make specific comments on the extent of competition between the Interconnect and the Eastern Gas Pipeline (EGP), that the coverage decision on the EGP provides some insight into the level of competition. It submits that information presented to the Australian Competition Tribunal (Tribunal) by Mr. Ergas in the 'coverage decision' for the Eastern Gas Pipeline suggested that there was high cross-price elasticity of demand of 2 between the EGP and the Interconnect. It submits further the Tribunal's consequent finding that there is low-cost developable capacity on the Interconnect means there is some direct competition between the Interconnect and the EGP. On the basis of analysis accepted by the Tribunal, TRUenergy states it is satisfied that there exists a degree of competition between the EGP and the Interconnect to allow unregulated expansion beyond 17 TJ/day.[648]

AGL also provides qualified support of GasNet's proposal. AGL states to the extent the EGP provides competition to the gas flows to NSW via Culcairn that GasNet's expansion policy is acceptable. However, it notes that this view would be subject to ownership structures emanating from the sale of Alinta and the divestment of its 35 per cent shareholding in APT.[649]

In contrast, Origin Energy submits there is no compelling reason to put aside coverage for expansions beyond 17 TJ/day. It considers that this may set a precedent for other withdrawal zones and believes this issue is more appropriately handled within the existing regulatory framework. It also notes that the proposal appears to create further uncertainty and complexity for users.[650]

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[647] GasNet, *Submission*, op. cit., p. 112.

[648] TRUenergy, op. cit., p. 10. TRUenergy refers to *Duke Eastern Gas Pipeline Pty Ltd* (2001) ACompT 2, [106] and [107].

[649] AGL, *Submission to the issues paper*, 26 June 2007, p. 3.

[650] Origin Energy, *Submission to the issues paper*, 9 July 2007, p. 3. Origin Energy also emphasises the importance of the Interconnect in managing security supply events.

8.5.4.2 Extensions

TRUenergy submits that GasNet's extensions policy should be amended. It submits GasNet should not have discretion as to whether small (less than $30 m or shorter than 15 km) extensions are covered. TRUenergy states its experience in calling for tenders for small laterals that run off trunk lines, is that other construction companies are reluctant to bid against the trunk line owners as these companies believe they are at a 25 per cent cost disadvantage, when bidding against an incumbent. TRUenergy submits then that there is no market for small laterals and that if GasNet chooses not to have a small pipeline covered it can exercise market power.[651]

8.5.5 Assessment

8.5.5.1 Coverage—expansions

GasNet only provides brief reasons to support its change from AA2 to allow for an exception from all expansions being covered, when an expansion is required to increase the capacity of withdrawals at Culcairn above the current capacity of 17 TJ/day:

> This is on the basis of the market influences and competitiveness between the Interconnect Pipeline and the EGP. Therefore, GasNet considers it not appropriate to regulate these tariffs.[652]

GasNet has not provided any indication of when such an investment might occur, within AA3. However, it proposes forecast new facilities investment to be constructed in time for winter 2009, directed at restoring the capacity (on a system peak day) at Culcairn for withdrawals to 17 TJ/day.[653] GasNet is then understood to be contemplating the possibility of a second expansion on top of the forecast new facilities investment it proposes for AA3. That is, GasNet proposes that if there is a further expansion after winter 2009, providing for capacity above 17 TJ/day at Culcairn, this should not be covered.

The ACCC considers two issues in relation to GasNet's expansion policy proposal below:

- the degree of market power GasNet may acquire (at the Interconnect) and
- contract carriage arrangements co-existing in the market carriage framework.

8.5.5.2 Expansions and market power

The ACCC has previously concluded that whilst other companies can compete to construct geographical extensions of pipelines, pipeline expansions by the service provider exhibit stronger economies of scale and scope, raising more possibility (through market power) to extract monopoly rent.[654] The purpose of coverage of a

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651 TRUenergy, op. cit., p. 10.

652 GasNet, *Submission*, op. cit., p. 112.

653 ibid., p. 48.

654 ACCC, *Access arrangement proposed by NT Gas Ltd for the Amadeus Basin to Darwin Pipeline Final Decision*, 4 December 2002, p. 153.

pipeline as considered by the Australian Competition Tribunal (Tribunal) is to prevent the consequence of misuse of market power. The Tribunal considered the consequence of 'significant' market power could be:

- to prevent the economically efficient operation of the pipeline[655]
- deter competition in upstream or downstream markets[656] or
- thwart the interests of users or prospective users.[657]

The ACCC must take account of these s. 2.24 factors in considering GasNet's expansions policy. In previous decisions the ACCC has, on a number of occasions, outlined reasons for requiring that expansions be covered unless the regulator consents:[658]

- A pipeline which is operating at or near capacity and requires expansion to satisfy demand, is indicative of the potential an incumbent service provider—if left unconstrained by competition or regulation—to exercise market power and extract monopoly rents by pricing expansions just below the point where it would no longer be commercially viable for a current or prospective user to continue with its proposal.
- An ability to exercise a degree of market power in setting terms and conditions, including tariffs, may in turn discourage investment and entry into downstream markets and in so doing produce an outcome that would be contrary to the interest of the public. If entry does occur, new entrants facing higher transportation costs may be unable to act as a competitive constraint on incumbents. The ability to extract monopoly rent will operate to limit effective competition in downstream markets and in turn limit any efficiency gains obtained. In addition to these factors the ability of a service provider to capture monopoly rents that would otherwise be passed onto households and businesses in the form of lower prices, may impact on the economic growth of the region.

The existence of excess demand *at the time of the expansion* will be an important factor in deciding whether market power exists but other factors will also be important. These include but are not limited to pipeline competition, supplies of gas from upstream markets, substitution possibilities involving other forms of energy, and the counter-veiling power of gas producers and gas users.[659]

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[655] In accordance with s. 2.24(d) of the code.

[656] Against the public interest in accordance with s. 2.24(e) of the code.

[657] In accordance with s. 2.24(f) of the code. See *Application by Epic Energy South Australia Pty Ltd* [2003] ACompT 5.

[658] ACCC, *Final Decision: Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 12 September 2001, pp. 171 and 172; ACCC, *Final Decision: ABDP*, 4 December 2002, pp. 152 and 153; see also ACCC, *Final Decision: East Australian Pipeline Limited Access arrangement for the Moomba to Sydney Pipeline System*, 2 October 2003, p. 293.

[659] See *Application by Epic Energy South Australia Pty Ltd* [2003] ACompT 5.

Of the factors which may go to determine whether market power exists, TRUenergy and AGL's submissions consider potential pipeline competition between the EGP and the Interconnect. The ACCC notes the analysis referred to by TRUenergy, however, was later qualified by the author as not reliable.[660] The ACCC notes further that price divergence between the two pipelines over the AA2 period does not appear to have led to marked change in gas consumption on the Interconnect.[661]

The proposal by GasNet raises similar issues to those considered by the ACCC in relation to the Moomba to Adelaide Pipeline (MAPS) AA proposals in 2001–02.[662] There, the service provider proposed future expansions generally would be uncovered. However, the ACCC considered there to be uncertainty as to how the broader gas market (pipelines) would develop during the access period and decided that:

> Given the uncertainty, the Commission considers that the best way forward is to modify the expansion policy so that the decision regarding whether or not an expansion should be covered can be made prior to the construction of the pipeline.[663]

The final AA reflected these comments. The ACCC considers it is difficult to draw conclusions as to whether at a future point in time market power will exist in relation to gas flows from this expansion. The factors mentioned above, including the upstream/downstream climate, substitution possibilities, and countervailing power of users are all subject to change over time. The relevant regulator and users would be better informed and able to comment on market power issues at the time a proposal was brought forward.

8.5.5.3 Interaction with the market carriage system

In submissions to the AA2 revisions, VENCorp stated that it was imperative that all expansions be covered on the PTS. It suggested it was impractical to have a situation where, for example, pipeline looping or a compressor upgrade results in an expansion

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660 National Competition Council, *Moomba To Sydney Pipeline System: Revocation applications under the National Gas Code: Final Recommendations*, November 2002, p. 166: The unreliability of the data analysis undertaken was concluded in a report also commissioned by the National Competition Council by Ordover and Lehr. Ordover J & Lehr W, *Should coverage of the Moomba-Sydney pipeline be revoked?*, 2001.

661 The ACCC understands that since 2001 tariffs on the EGP have risen consistent with a CPI-based price path: ibid; see also Alinta Infrastructure Holdings, *Eastern Gas Pipeline Transportation Tariffs Effective 1st January 2007 Reference Tariffs*, <http://www.aih.net.au/assets/download/EGP/2007/070206EGPTariffs1Jan07.pdf> viewed 1 November 2007; and Alinta Infrastructure Holdings, *Eastern Gas Pipeline Transportation Tariffs Effective 1st January 2006 Reference Tariffs*, <http://www.aih.net.au/assets/download/EGP/EGPTariffs-2006.pdf> viewed 1 November 2007.

In contrast, between 2003 and 2007 tariffs have declined each year on the Victorian PTS (see chapter 6.2 of this draft decision). However, volumes at Culcairn were 2.1 PJ in 2003 and lower in 2006 at 1.8 PJ: see VENCorp, *2003 Gas Annual Planning Report*; and VENCorp, *2006 Gas Annual Planning Report*.

662 Epic Energy, *Access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 1 April 1999.

663 ACCC, *Final Approval: access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 21 July 2002, p. 42.

of capacity that is not available for VENCorp to operate under the MSO rules.[664] It noted from an operational point of view it would be impossible to distinguish the difference between that part of the facility or pipeline that is providing the original capacity and that which is providing the expanded capacity.[665] GasNet did not respond to VENCorp's comments because it stated, correctly, that VENCorp had misread its AA, which provided that all expansions would be covered. However, the ACCC considers that GasNet will need to address these concerns by VENCorp in the future if it is to propose an uncovered expansion. For instance, GasNet did not provide details on how VENCorp and/or it would separate out flows for the purposes of tariffing. Origin Energy also considered that the arrangements introduced uncertainty to users.[666] The ACCC would also need to be satisfied that introduction of an uncovered expansion would not introduce disproportionate complexity to users against their interests.[667] Moreover, the ACCC must take account of whether the proposals will affect the safe and reliable operation of the pipeline.[668]

8.5.5.4 Conclusions

The ACCC considers that an amendment to GasNet's proposal is necessary to account for the interests of users and prospective users and the public interest[669] given uncertainty as to whether GasNet may be able to exercise market power at the time it chooses to expand the pipeline. Furthermore, any complexities arising from introducing contract carriage arrangements to a market carriage system also need be addressed by the service provider.

The ACCC considers the appropriate amendment, which also recognises GasNet's legitimate business interests, is to allow GasNet opportunity to propose within the period that an expansion be uncovered prior to construction.[670]

The ACCC considers that if GasNet does in the future propose an expansion to be uncovered, in order for the application to be addressed properly, GasNet should provide more evidence as to:

- constraints on its ability to exercise market power (at that time)
- how a contract carriage arrangement could co-exist with the market carriage system and
- how the concerns of VENCorp would be addressed.

Accordingly, the ACCC proposes the following amendment as necessary:

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664 VENCorp, *Submission to the ACCC on Access Arrangement Issues Paper*, 13 May 2002, p. 15.

665 ibid.

666 Origin Energy, op. cit., p. 3.

667 In accordance with s. 2.24(f) of the code.

668 In accordance with s. 2.24(c) of the code.

669 In accordance with ss. 2.24(e) and 2.24(f) of the code.

670 Consistent with s. 2.24(a) of the code.

Proposed amendment 32

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 5.1(c) of the proposed revised access arrangement to read:

> 'An expansion required to increase withdrawals at Culcairn over and above the current capacity of 17 TJ/day will be covered unless the Regulator, before the decision to construct the New Facility is made by the Service Provider, agrees that it should not be covered.'

(i) *Coverage—extensions*

The ACCC has considered in the past there is an ability for businesses to compete for the opportunity to construct extensions to an existing pipeline.[671] Consistent with this ability and there being a market for the construction of pipeline extensions, the ACCC has allowed the pipeline owner a discretion as to whether to have an extension covered.

TRUenergy submits however is that there is no market for small extensions. It notes its experience in calling for tenders for small laterals is that other parties have chosen not to tender against the incumbent because they believe the owner of the trunk line has a distinct cost advantage (estimated to be around 25 per cent).[672] However, TRUenergy has not provided any evidence in support of its view, which would demonstrate a pattern of market behaviour. In particular no evidence has been received as to:

- TRUenergy or others requesting bids but only receiving a bid from an incumbent
- TRUenergy or others receiving bids from the incumbent and other parties and the relative costs of these bids or
- invoices rendered by incumbents for the construction of short laterals.

TRUenergy provided little detail, qualitative or quantitative, to support the underlying assertion that the incumbent has market power such that this market which other large pipeline businesses should be able to operate in is uncompetitive.

To depart from allowing GasNet to continue its AA2 approach to extensions (which is consistent with ACCC decisions for other pipelines), the ACCC would need more substantial evidence as to the nature of any argued ability of GasNet to exercise market power in the market for small pipeline extensions.

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[671] ACCC, *Final Decision: Access Arrangement Proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline*, 4 December 2002, p. 153; ACCC, *Final Decision: Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 12 September 2001, p. 172.

[672] TRUenergy, op. cit., p. 10.

8.6 Review of the access arrangement

8.6.1 Code requirements

Section 3.17 of the code requires an AA to include a date when the service provider must submit revisions to the AA (revisions submission date) and the date when the revisions are expected to take effect (revisions commencement date).

In deciding whether these two dates are appropriate, the relevant regulator must consider the objectives contained in s. 8.1 of the code. Having done so, the relevant regulator may require an amendment to the proposed AA to include earlier or later dates. The relevant regulator may also require that specific major events be defined as a trigger that would require the service provider to submit revisions before the revisions submission date in accordance with s. 3.17(ii) of the code.

Section 3.18 of the code states that an AA period accepted by the relevant regulator may be of any duration. However, if the period is longer than five years, the regulator must consider whether mechanisms should be included to address the potential risk that forecasts, on which terms of the proposed AA are based, could subsequently prove to be incorrect.

8.6.2 Current access arrangement provisions

Clause 2.2 of GasNet's second AA currently specifies 31 March 2007 as the revisions submissions date and 1 January 2008 as the revisions commencement date.

8.6.3 Proposal

GasNet proposes 31 March 2012 as the new revisions submissions date and the revisions commencement date to be the later of 1 January 2013 and the date on which approval of revisions to the AA take effect.

GasNet notes that the adoption of a five year AA is consistent with general practice and AA1 and AA2. GasNet also states that the revisions commencement date coincides with the expiration of the SEA.

8.6.4 Submissions

No submissions were received on this aspect of the proposed AA.

8.6.5 Assessment

The ACCC considers that GasNet's proposed dates for submission and commencement of the revised AA are consistent with the objectives in s. 8.1 of the code and that a five year AA period is also consistent with these objectives.

9 Draft decision

Under s. 2.13(b) of the code, the ACCC proposes not to approve GasNet's revised access arrangement for the PTS in its current form. This draft decision states the amendments (or nature of the amendments, as appropriate) which have to be made in order for the ACCC to approve the proposed revised access arrangement at the relevant sections of this draft decision. The proposed amendments are also listed below.

10 Proposed amendments

Proposed amendment 01

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 2.1 of its proposed revised access arrangement information to reflect table 3.1.4 of this draft decision.

Proposed amendment 02

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 2.1 of the proposed revised access arrangement information to reflect table 3.2.3 of this draft decision for roll-in to the capital base.

Proposed amendment 03

Before the proposed revised access arrangement can be approved, GasNet must:

- amend cl. 3.6 of the proposed revised access arrangement information to reflect table 3.3.7 of this draft decision
- demonstrate how the portion of the Northern zone necessary to address the anticipated breach of the minimum system pressure requirements and the Warragul loop are reasonably expected to satisfy the requirements of the economic feasibility test in s. 8.16(a)(ii)(A) of the code in order to include the amounts the ACCC considers are reasonably expected to satisfy the requirements of the prudent investment test in cl. 3.6 of the proposed revised access arrangement information
- demonstrate how the proposed Pakenham loop is reasonably expected to satisfy the requirements of the system integrity test in s. 8.16(a)(ii)(C) of the code in order to include the amount the ACCC considers is reasonably expected to satisfy the requirements of the prudent investment test in cl. 3.6 of the proposed revised access arrangement information.

Proposed amendment 04

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 4.6 of the proposed revised access arrangement and retain the definition of partially redundant assets as it appears in the second access arrangement.

Proposed amendment 05

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.3.3 of the proposed revised access arrangement to reflect table 3.5.6 of this draft decision.

Proposed amendment 06

Before the proposed revised access arrangement can be approved, GasNet must amend the rate of return in cl. 3.2 of the proposed access arrangement information to reflect the ACCC's estimates set out in table 4.1.7 of this draft decision.

Proposed amendment 07

Before the proposed revised access arrangement can be approved, GasNet must implement the administrative arrangements 1 to 7 described above in this chapter 5.1 of this draft decision.

Proposed amendment 08

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.5.2 of the proposed revised access arrangement information to reflect table 5.1.13 of this draft decision.

Proposed amendment 09

Before the proposed revised access arrangement can be approved, GasNet must:

- amend the definition of an Insurance Event in cl. 9.1 of its proposed revised access arrangement to only cover circumstances where GasNet is required to pay a deductible in connection with a claim under an insurance policy and
- remove the definition of Minimum Insurance Level from in cl. 9.1 of its proposed revised access arrangement

Proposed amendment 10

Before the proposed revised access arrangement can be approved, GasNet must amend the definition of a Pass Through Event in cl. 9.1 of its proposed revised access arrangement to remove the reference to an Asbestos Event.

Proposed amendment 11

Before the proposed revised access arrangement can be approved, GasNet must include:

- changes to its fuel gas costs from the base year (2006) as a pass-through event, excluding any fuel gas costs associated with the Euroa compressor and
- as a condition that GasNet must tender for its fuel gas requirements.

Proposed amendment 12

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 4.2 of the proposed revised access arrangement information to incorporate the annual GPG forecasts in table 5.4.7 of this draft decision.

Proposed amendment 13

Before the proposed revised access arrangement can be approved, GasNet must include top-ten peak day volume forecasts for each injection zone in cl. 4 of the proposed revised access arrangement information.

Proposed amendment 14

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.7 of the proposed revised access arrangement information to reflect table 5.5.3 of this draft decision.

Proposed amendment 15

Before the proposed revised access arrangement can be approved, GasNet must amend the revised access arrangement:

- so that the final withdrawal tariffs as set out in cl. 1.3 of schedule 1 of the proposed revised access arrangement to reflect the allocation of costs to withdrawal zones based on the asset group annual and peak direct cost unit rates as these are derived in the modelling for the AA2 period and
- so that final injection tariffs as set out in cl. 1.2 of schedule 1 of the proposed revised access arrangement to reflect the allocation of costs associated with each injection pipeline segment directly to the relevant injection pipeline consistent with the modelling for the AA2 period.

Proposed amendment 16

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 1.3 of schedule 1 of the revised access arrangement to recover

- 100 per cent of the MVP incremental costs directly from the pipeline and
- retain the two part tariff for users located on the Murray Valley pipeline: one part to recover the costs associated with the Murray Valley pipeline extension (Murray Valley incremental tariff) and the other part to recover the costs (calculated as per GasNet's current cost allocation methodology using specific direct cost unit rates) associated with transportation of gas on the withdrawal pipes to the beginning of the Murray Valley pipeline at Chiltern Valley (Chiltern Valley tariff).

Proposed amendment 17

Before the proposed revised access arrangement can be approved, GasNet must retain the zonal withdrawal tariffs for tariff-V users and remove the withdrawal tariff-V set out in cl. 1.3(b) of schedule 1 of the proposed revised access arrangement.

Proposed amendment 18

Before the proposed revised access arrangement can be approved, GasNet must amend the proposed revised access arrangement to maintain the current injection tariff structure, where the peak period applies to the top 10 peak days during the winter period, instead of applying the charge over the whole winter period as proposed in cl. 1.2 of schedule 1 of the proposed revised access arrangement.

Proposed amendment 19

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 1.3(g) of schedule 1 of the proposed revised access arrangement to remove the prudent discount for tariff-D users at Pakenham.

Proposed amendment 20

Before the proposed revised access arrangement can be approved, GasNet must amend the proposed revised access arrangement to calculate its export tariff (as proposed in section 11.6.2 of the revised access arrangement submission) based on the tariff model used in the second access arrangement.

Proposed amendment 21

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 1.3(b) of schedule 1 of the proposed revised access arrangement to include matched rebates for tariff-V users in the North Hume, Murray Valley, Interconnect and Wodonga withdrawal zones for gas injected at Culcairn.

Proposed amendment 22

Before the proposed revised access arrangement can be approved, GasNet must:

- allocate direct costs to the Geelong withdrawal zone based on specific direct cost unit rates and
- calculate a Geelong zonal withdrawal tariff for tariff-V users.

Proposed amendment 23

Before the proposed revised access arrangement can be approved, GasNet must insert the following directly below the heading 'AR' in schedule 4.2 of the proposed revised access arrangement:

'For the avoidance of doubt, actual revenue includes revenue derived from authorised maximum daily quantity/credit certificates as allocated under the Market and System Operations Rules.'

Proposed amendment 24

Before the proposed revised access arrangement can be approved, GasNet must amend the formula in schedule 4.6 of the proposed revised access arrangement to read:

'$WAAV = actual\,VW + TS \times (target\ EDD - actual\ EDD)$'

Proposed amendment 25

Before the proposed revised access arrangement can be approved, GasNet must amend the definition of VW in schedule 4.6 of the proposed revised access arrangement to read:

'VW is the actual volume withdrawn from the PTS excluding:

- any volume withdrawn from a non-covered expansion of withdrawal capacity at Culcairn
- any transmission refills at the Western Underground Storage or Liquefied Natural Gas facility at Dandenong and
- forecast volumes for the incremental Murray Valley tariff.'

Proposed amendment 26

Before the proposed revised access arrangement can be approved, GasNet must amend the definition of VATR in schedule 4.4 of the proposed revised access arrangement to remove from TR and TV as defined therein revenues and volumes associated with:

- any transmission refills at the Western Underground Storage or Liquified Natural Gas facility at Dandenong and
- the incremental Murray Valley tariff.

Proposed amendment 27

Before the proposed revised access arrangement can be approved, GasNet must amend Table 7-1 in cl. 7.1 of its revised access arrangement information to include the temperature sensitivities used by VENCorp for its annual demand forecasts in its 2006 Gas Annual Planning Report.

Proposed amendment 28

Before the proposed revised access arrangement can be approved, GasNet must amend schedule 4.1(a)(ii)(B) of the proposed revised access arrangement and remove all the words which follow 'Y is 2%'.

Proposed amendment 29

Before the proposed revised access arrangement can be approved, GasNet must

- remove cl. 7.2(i) of the proposed revised access arrangement and
- replace 'use' with 'take into account' in cl. 7.2(h)(ii) of the proposed revised access arrangement.

Proposed amendment 30

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 3.2 of the proposed revised access arrangement to reflect that GasNet will provide gas transportation services directly to users.

Proposed amendment 31

Before the proposed revised access arrangement can be approved, GasNet must:

- amend cl. 8.2 of the proposed revised access arrangement to be consistent with s. 5.7 of the MSO rules and
- to reflect that the responsibility for complying with the obligations imposed under ss. 3.12–3.15 of the code is allocated to VENCorp.

Proposed amendment 32

Before the proposed revised access arrangement can be approved, GasNet must amend cl. 5.1(c) of the proposed revised access arrangement to read:

'An expansion required to increase withdrawals at Culcairn over and above the current capacity of 17 TJ/day will be covered unless the Regulator, before the decision to construct the New Facility is made by the Service Provider, agrees that it should not be covered.'

Appendix A: Submissions

The following interested parties provided submissions to the issues paper published by the ACCC on 24 May 2007.

Organisation	**Date received**
AGL	26 June 2007
TRUenergy	27 June 2007
Australian Paper	29 June 2007
Origin Energy	9 July 2007
Energy Users Association of Australia	6 August 2007
Energy Users Coalition of Victoria	10 August 2007

Appendix B: Attachment A of the code

Information disclosure by a service provider to interested parties

Pursuant to s. 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 C: Consultant reports

Report	**Date received**
ACIL Tasman	13 August 2007
Final report: GasNet GPG forecasts—Review of GasNet gas power generation forecasts within the 2008–12 access arrangement period	
Ross Calvert Consulting Pty Ltd	14 September 2007
GasNet Revised Access Arrangement—Assessment of Proposed Operating Expenditure Scope and Workload Changes	
Sleeman Consulting	19 September 2007
GasNet Principal Transmission System: Review of Proposed New Facilities Investments	

Appendix D: Pipeline map