Draft Decision

Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline

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Contents

Abbreviations and glossary of terms

ABDP	Amadeus Basin to Darwin Pipeline
Access arrangement	Arrangement for access to a pipeline provided by a pipeline owner/operator that has been approved by the regulator
AGA	Australian Gas Association
ACQ	Annual Contract Quantity
AGL	The Australian Gas Light Company
Agility	Agility Management Pty Limited
AGLP	AGL Pipelines (NSW) Pty Limited
APT	Australian Pipeline Trust Limited
ATO	Australian Taxation Office
BHP	BHP Limited
CAPM	Capital Asset Pricing Model
The Code	National Third Party Access Code for Natural Gas Pipeline Systems
Commission	Australian Competition and Consumer Commission
Connell Wagner	Connell Wagner Pty Limited
Covered pipeline	Pipeline to which the provisions of the Code apply
CPI	Consumer Price Index
CWP	Central West Pipeline
DAC	Depreciated Actual Cost
DORC	Depreciated Optimised Replacement Cost
DRC	Depreciated Replacement Cost
Draft Regulatory Principles	Draft Statement of Principles for the Regulation of Transmission Revenue
EAPL	Eastern Australian Gas Pipeline Limited

Epic	Epic Energy South Australia Pty Limited
GJ	Gigajoule
GPAL	Gas Pipelines Access Law
GST	Goods and Services Tax
ICB	Initial Capital Base
IPART	Independent Pricing and Regulatory Tribunal
IRR	Internal Rate of Return
KPI	Key Performance Indicator
LNG	Liquefied Natural Gas
MAOP	Maximum Allowable Operating Pressure
MAPS	Moomba to Adelaide Pipeline System
MDQ	Maximum Daily Quantity
MHQ	Maximum Hourly Quantity
MSP	Moomba to Sydney Pipeline System
Nabalco	Nabalco Pty Limited
NEC	National Electricity code
NT	Northern Territory
NT Gas	The operator from time to time of the Pipeline which at 25 June 1999 is NT Gas Pty Ltd as trustee of the Amadeus Gas Trust
NTPG	NT Power Group Pty Limited (Power Generation and Transmission)
NTS	New Tax System
NPV	Net Present Value
O&M	Operating and Maintenance
ODV	Optimised Deprival Value
ORC	Optimised Replacement Cost

ORG	Office of the Regulator-General, Victoria
PAWA	Power & Water Authority
PJ	Petajoule (equal to 1 000 000 GJ)
Phillips	Phillips Petroleum Company (Exploration & Production (E & P)) Limited
RC	Replacement Cost
Santos	Santos Offshore Australia Business Unit
Shell	Shell Development (Australia) Pty Limited
TJ	Terajoule (equal to 1 000 GJ)
TPA	Transmission Pipelines Australia Pty Limited
Venton & Associates	Venton & Associates Pty Limited
WACC	Weighted Average Cost of Capital
Woodside	Woodside Energy Limited

Executive Summary

Background

On 25 June 1999, NT Gas submitted to the Australian Competition and Consumer Commission an access arrangement for the Amadeus Basin to Darwin Pipeline (ABDP). It sought approval under the *National Third Party Access Code for Natural Gas Pipelines Systems* (the Code).

The ABDP transports gas from the Palm Valley and Mereenie gas fields to Darwin. The majority of gas (97 per cent) transported is used in the generation of electricity. The pipeline is fully contracted until 2011. AGL holds a 96 per cent interest in NT Gas.

The access arrangement describes the terms and conditions on which third parties will gain access to the pipeline. The Commission's assessment involved public consultation and an examination of information provided by NT Gas and interested parties.

The Commission's assessment

As the majority of gas hauled on the ABDP is used in electricity generation, the proposed reference tariff has in the long term the potential to affect a range of residential and commercial energy users.

This Draft Decision demonstrates the Commission's ability to apply the National Gas Code in a flexible manner to accommodate the specific characteristics and risks of the ABDP.

The Commission believes it has balanced NT Gas' interests with those of potential access seekers. The reference tariff proposed by the Commission would generate sufficient revenue to cover efficient operating costs, depreciation and a return on investment commensurate with assumed risks and current market parameters.

In its access arrangement, NT Gas sought a higher WACC as compensation for the risk that the pipeline might be stranded from 2011. The Commission proposes that the risk of stranding should be managed through accelerated depreciation rather than a premium on the return on equity. This will enable NT Gas to recover most of its capital investment by 2011, while at the same time recognising the reduced economic value of the pipeline after the expiration of existing contracts.

The Draft Decision will give NT Gas a benchmark return on equity of 12 per cent. This is comparable to average returns earned on the Australian share market and by regulated energy businesses in North America and the United Kingdom.

Under the National Gas Code, NT Gas could achieve a return on equity in excess of 12 per cent through lower than forecast operations and maintenance costs and the sale of non-reference services.

NT Gas proposed a reference tariff of $3.46 for the first year (2001/02)[1] of its access arrangement. The Commission believes this is unreasonably high, and has proposed a tariff of $1.90/GJ. This would provide sufficient revenue to cover forecast efficient costs (including capital costs) of running the pipeline. The main reason for the difference is the treatment of depreciation since 1986, with the Commission establishing a substantially lower capital base than that proposed by NT Gas.

The Commission believes that the amendments proposed in this Draft Decision would ensure fair access and appropriate signals to parties involved in future negotiations involving the ABDP.

Draft Decision at a glance

Parameter	NT Gas Proposal	ACCC Draft Decision	Page Ref.
Ownership - basis for the assessment	The ABDP is owned by a consortium of banks and leased by NT Gas. NT Gas calculated tariffs for the pipeline system as if it were a single entity.	The Draft Decision treats the pipeline as if it is under common ownership and operation and calculates appropriate tariffs for the pipeline system as a single entity.	p. 8
Optimised Replacement Cost (ORC)	NT Gas proposed ORC of $318.96m	Draft Decision proposes ORC of $322m.	p. 26
Depreciated Optimised Replacement Cost (DORC)	NT Gas proposed DORC of $265m at 1 July 1999.	The Draft Decision proposes an ICB (before adjusting for deferred tax liability) at 1 July 1999 of $198.8m. The key factor for the difference between the two valuations is due to the treatment of depreciation since 1986.	p. 30
Deferred Tax Liability		The Draft Decision determines a deferred tax liability of $12.9m at 1 July 1999.	p. 34
Initial Capital Base	NT Gas has proposed an initial capital base of $265m at 1 July 1999.	The Draft Decision proposes an initial capital base at **1 July 2001** of **$176.2m**, after adjusting for deferred tax liability, depreciation, capital expenditure and inflation.	p. 35

[1] Given that the access arrangement period will be five years from the date of final approval, the Commission has determined revenues and tariff for the five-year period commencing 1 July 2001.

New Facilities Investment	NT Gas proposed an estimate capital expenditure program for the five year period, including $2.26m expansion capital to increase the capacity of the Mereenie supply line.	The Draft Decision concludes that the proposed capital expenditure forecast by NT Gas is likely to meet the criteria in section 8.16 of the code. However, the Commission will review the capital expenditure in the next access arrangement period against the section 8.16 criteria.	p. 36
Depreciation allowance	NT Gas proposes to depreciate the pipeline assets using accelerated depreciation to $61.84m in 2011 and standard straight line thereafter until the expiration of the asset's remaining technical life in 2066.	The Draft Decision accepts NT Gas' arguments about future risks of stranding and proposes a depreciation schedule based on accelerated depreciation of the initial capital base of $176.2m to a residual value of $61.84m in 2011.	p. 42
Rate of return	NT Gas proposed a return on equity between 14.3 and 17.3% per annum on the initial capital base of $265m.	The Draft Decision applies the Commission's standard post-tax nominal framework to calculate an appropriate rate of return for the pipeline. The post-tax nominal cost of equity for the pipeline is 12 per cent. This return would be on the initial capital base of $176.2m.	p. 51
Non-capital costs	NT Gas aggregated forecasts of non-capital costs and historical costs to arrive at best estimates for this access arrangement period.	The Draft Decision concludes that the operating, maintenance and other non-capital costs for the ABDP are reasonable.	p. 70
Forecast revenue	NT Gas proposed revenue of $52.0m for the year ending 30 June 2002.	The Draft Decision forecasts revenue for the year ending 30 June 2002 of $29.8m. The key to this difference is the treatment of depreciation of the ORC.	p. 73
Cost allocation and tariff setting	NT Gas proposed a zonal pricing structure. The three zones are between Amadeus Basin, Warrego, Mataranka and Darwin.	The Draft Decision accepts zonal pricing as an appropriate methodology for determining tariffs at this stage, but seeks further comment.	p. 77
Incentive structure	NT Gas proposed a rebatable service in the form of its interruptible service.	NT Gas must adjust its rebate mechanism to show how revenue from interruptible services will be distributed.	p. 81

Fixed principle	NT Gas proposed one Fixed Principle relating to the roll-in of new facilities investment at the commencement of the next access arrangement period.	The Draft Decision rejects the Fixed Principle.	p. 81
Back haul tariffs	NT Gas proposed only a forward haul service.	Given the potential for Timor Sea gas to come onshore, a number of interested parties have sought the inclusion of a back haul tariff. It is difficult to determine whether or not the demand for a back haul service satisfies section 3.3 of the Code.	p. 100
Review trigger		The Draft Decision suggests a trigger mechanism might be best for dealing with back haul tariffs.	p. 104
Queuing Policy	NT Gas proposed in the fourth dot point of clause 6.4 of the access arrangement, that an existing user with a contractual right in force as at 25 June 1999 would have pre-emptive rights over capacity reservation.	The Draft Decision requires NT Gas to remove the fourth dot point of clause 6.4.	p. 114
Extensions / Expansions policy		The Draft Decision requires NT Gas to amend its proposed extensions and expansions policy to require it to obtain the Commission's consent before electing to omit new facilities (either extensions or expansions) from the covered pipeline.	p. 116

Key Issues

Significance of the Draft Decision

NT Gas does not anticipate revenue being generated by the sale of the Reference Service or Negotiated service during the access arrangement period as the capacity of the ABDP is fully committed to users under pre-existing transportation contracts. As a consequence, this Draft Decision is likely to have limited immediate impact for existing users.

However, the Draft Decision will be an important reference point for future negotiations on gas haulage services in the NT especially with uncertainty about delivery of Timor Sea gas to Darwin.

NT Gas claims revenue under its pre-existing contracts is less than the total revenue likely under the code. The tariff proposed by NT Gas for the transportation of gas through all three zones in the first year of the access arrangement (2001/02) is $3.46/GJ. The Draft Decision indicates that NT Gas' proposed tariffs are at an unreasonably high level. Under the revised tariff path, a customer in zone three will pay $1.90/GJ during the same period.

Initial capital base

Optimised Replacement Cost (ORC)

The ORC of the pipeline system has been examined carefully by both NT Gas and the Commission. NT Gas' proposed ORC was subject to comment from interested parties and independent review by Connell Wagner. NT Gas then engaged Venton & Associates to comment on Connell Wagner's review. Connell Wagner in turn reviewed Venton's comments. Finally, the Commission conducted its own assessment of ORC based on all available material. The Commission proposes to adopt its own ORC estimate of $322 million.

The results of these analyses are summarised in Table 1.

Table 1: Comparison of ORC valuations

	NT Gas	Connell Wagner	ACCC
ORC Valuations ($m)	$319	$308	$322

Initial Capital Base valuation

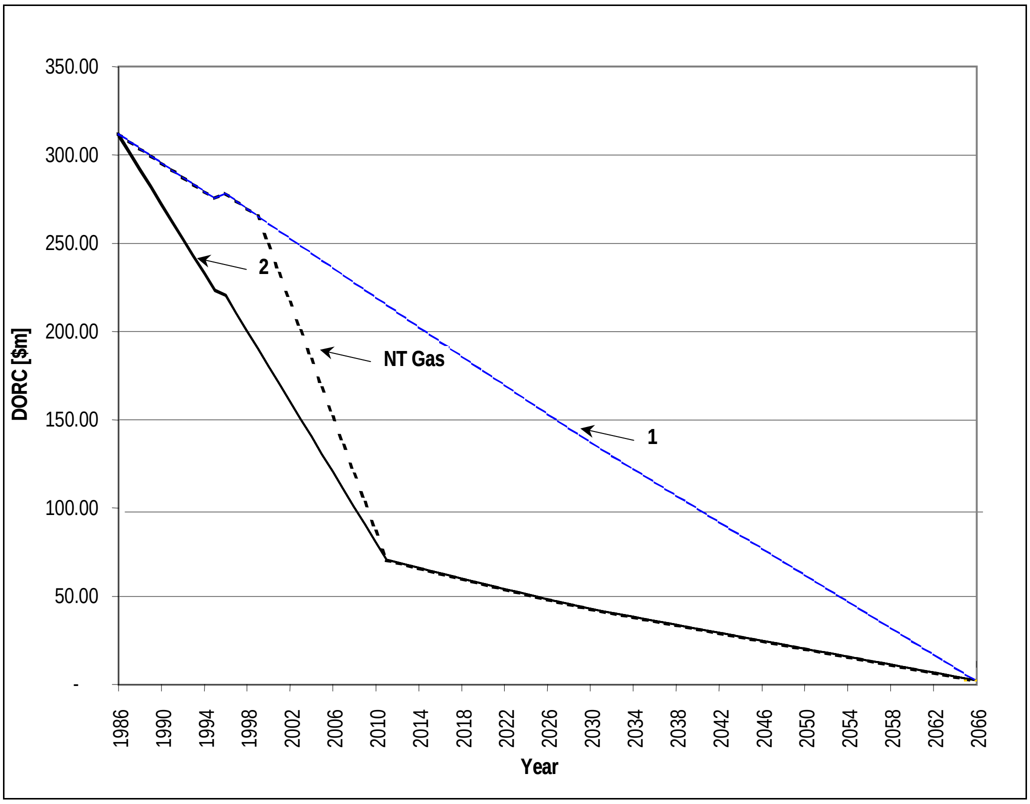
The treatment of depreciation since 1986 is the primary factor causing the significant difference in the initial capital base proposed by NT Gas and the Draft Decision. Figure 1 shows three alternative approaches to depreciation:

- *NT Gas* – standard-line depreciation base on the technical life of the pipeline (80 years) until 1 July 1999, accelerated depreciation to a residual value of $61.84m[2] at 1 July 2011 and standard straight-line depreciation until 2066;

- *Scenario 1* – standard straight-line depreciation over the technical life of the pipeline; and

- *Scenario 2* – accelerated depreciation from pipeline commissioning to 2011 and thereafter standard straight-line depreciation over the remaining technical life of the pipeline. This option retains the residual asset value of $61.84m (at 1 July 2011) recommended by NT Gas.

Figure 1: ICB valuation of the ABDP



Source: Connell Wagner, Review of NT Gas' DORC valuation for the ABDP

NT Gas depreciated its ORC on a straight-line basis over the economic life of the assets comprising the ABDP to establish a DORC of $265m at 1 July 1999. More specifically, pipeline assets, which constitute a significant portion of the ABDP's ORC valuation, were depreciated based on an 80-year life.

[2] $61.84m is the residual value at 2001, proposed by NT Gas in its Access Arrangement Information.

The Commission considers that the DORC valuation, as calculated by NT Gas, does not provide an appropriate valuation of the ABDP's pipeline assets. It is the Commission's view that the risk of stranding currently faced on the pipeline was evident during the construction of the pipeline. It is therefore difficult to accept that NT Gas, as a prudent investor, would not recognise the likelihood of stranding earlier and structure its tariffs accordingly.

In particular, NT Gas has submitted in its access arrangement information that the residual value of the pipeline on 1 July 2011 will be $61.84m. On the basis of evidence provided, the Commission is satisfied that $61.84m is an appropriate estimate of the residual value in 2011. In addition, the Commission has reason to believe that this estimated valuation was in existence in 1986. Two key factors support this.

First, there is uncertainty about the potential gas reserves in the Amadeus Basin. NT Gas says reserves are only expected to meet Northern Territory demand until 2015. Second, NT Gas' major foundation contract is expected to expire in 2011.

The Commission has determined an initial capital base (before adjusting for deferred tax liability) for the ABDP as at 1 July 1999 of $198.8m. The Commission calculated the initial capital base using accelerated depreciation of ORC based on the residual value of $61.84m in 1 July 2011.

Deferred tax liability

The Commission proposes to deduct an allowance for deferred tax liability (measured as the accumulated prima facie tax expense) from the initial capital base. This approach acknowledges that the deferred tax amount is similar to an interest free loan from the Australian Taxation Office (ATO) or a free source of capital. It recognises that, under the post-tax regulatory framework, NT Gas will be fully compensated in regulated revenues for expenditure to meet those liabilities as they become due. In other words, the adjustment ensures that the service provider is not compensated twice for its tax liabilities.

To make an appropriate deferred tax liability adjustment it is necessary to calculate a set of statutory accounts for the company as if it owned the assets and applied the accelerated tax provisions. The accumulated deferred tax liability remaining at 1 July 1999 is estimated to be $12.9m. Adjusting for the amount of the remaining deferred tax liability provides an initial capital base of $185.8m at 1 July 1999.

Initial Capital Base as at 1 July 2001

Given that the access arrangement period will be five years from the date of final approval, the Commission has determined revenues for the five-year period commencing 1 July 2001. Taking the initial capital base valuation at 1 July 1999 adjusted for deferred tax liability as well as inflation, capital expenditure and depreciation since then, the Commission has calculated an initial capital base at 1 July 2001 of $176.2m for the ABDP.

Depreciation allowance

The treatment of on-going depreciation has a significant influence on the revenue stream. NT Gas proposed accelerated depreciation of the initial capital base (shown in Figure 1) to reflect its concern about the sustainability of current levels of throughput over the life of the pipeline. It argued that there is significant uncertainty given the expiration of its foundation gas transportation contract in 2011, the lack of information on future production capacity of the Amadeus Basin and the potential for Timor Sea gas to enter the Northern Territory.

The Draft Decision accepts these arguments and proposes to depreciate the pipeline assets to a residual value $61.84m in 2011. The pipeline will then be depreciated on a standard straight line basis over its remaining economic life (to 2066). This approach to on-going depreciation is consistent with the Draft Decision's treatment of depreciation in calculating the initial capital base.

Rate of return

National Economics Research Associates (NERA) recently released a paper comparing returns of regulated utilities between North America, the United Kingdom and Australia. The key outcome of the study is that returns given by Australian regulators are broadly consistent with returns in North America, which are higher than those in the United Kingdom.

The Draft Decision will give NT Gas a benchmark return on equity of 11.96 per cent.[3] This compares favourably to average returns earned on the Australian share market and by regulated energy businesses internationally. The table below compares the returns given by the ACCC in recent decisions and those earned through super funds and the Australian stock market.

[3] While this amount has been applied to the revenue model, it has been referred to in rounded terms (12 per cent) elsewhere in this Draft Decision.

Table 2: Return on equity comparisons†

ACCC Final Decision, Oct-98	Victorian gas transmission pipeline systems	13.2
ACCC Final Decision, Jan-00	NSW & ACT electricity transmission (Transgrid & EnergyAustralia)	13.9
ACCC Final Decision, Jun-00	APT – Central West Pipeline	15.4
ACCC Draft Decision, Aug-00	Epic Energy – Moomba-Adelaide Pipeline System	13.0
ACCC Draft Decision, Dec-00	EAPL – Moomba-Sydney Pipeline System	13.0
ACCC Final Decision, Feb-01	SMHEA transmission (Snowy Mtns Hyrdro-Electric Authority)	11.2
ACCC Draft Decision, May-01	NT Gas – Amadeus Basin to Darwin	12.0
Australia – Super funds (Mercer survey)	Pooled superannuation funds – 3 year average return	10.4
Australian Stock Exchange (ASX Fact Book 1999)	Stock market 10 year average ROE – June 1988 to June 1998, (All Ords)	11.3

† Post-tax nominal.

The Commission has established the rate of return for NT Gas on the same basis as that for both the MSP and MAPS *Draft Decisions* and a fall in the risk free rate is the reason for the differences in rates of return.

As outlined in its *Draft Regulatory Principles* and in recent decisions,[4] the Commission prefers to use a post-tax regulatory framework. The post-tax nominal return on equity is better understood by financial markets than the pre-tax real weighted average cost of capital (WACC), with shareholder returns typically being expressed in nominal, post-tax terms. Furthermore, the post-tax nominal return on equity determines whether investors are willing to advance equity to finance the capital infrastructure required to provide services.

Based on its own analysis and the parameters identified by the Commission as being appropriate to NT Gas within this access arrangement period, a nominal cost of equity of 12 per cent per annum was derived.

4 ACCC, 'NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04', *Decision*, 25 January 2000 and ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision*, 30 June 2000.

Under the National Gas Code, NT Gas could achieve a return on equity in excess of 12 per cent through lower than forecast operations and maintenance costs and the sale of non-reference services.

Table 3: WACC estimates

	per cent	
	NT Gas proposal	**Commission Draft Decision**
Nominal cost of equity	14.3-17.3	11.96
Nominal pre-tax cost of debt (r_d)	6.7-7.4	6.20
Nominal vanilla WACC	n/a	8.51
Post-tax nominal WACC	6.5-10.9	7.35
Pre-tax nominal WACC	10.2-17.0	8.59[(b)]
Pre-tax real WACC	8.5-11.7[(a)]	6.49[(b)]

Source: Access arrangement information, p. 26 and Commission analysis.
Note: (a) calculated by NT Gas using the forward transformation formula: $W_{tr} = (1+W_t)/(1+f)-1$
(b) obtained from the Commission's cash flow analysis.

Non-capital costs

NT Gas aggregated forecasts of non-capital costs and historical costs to arrive at best estimates for this access arrangement period. The Draft Decision compared the ABDP and other transmission pipelines against a number of key performance indicators and concluded that the operating, maintenance and other non-capital costs for the ABDP are reasonable.

Forecast revenue

NT Gas applied a cost of service framework to determine total revenue. As a result of the Commission's amendments the forecast regulated revenue for the ABDP will be different to that proposed by NT Gas. The forecast revenue determined by NT Gas and in the Draft Decision are set out in Table 4.

Table 4: Comparison of forecast revenue, 2002 to 2006

	Forecast revenue ($ million)	
Year ending 30 June	**NT Gas**	**ACCC**
2002	53.3	29.8
2003	52.9	29.6
2004	52.8	30.2
2005	53.7	30.1
2006	52.1	29.9

As the pipeline is fully contracted until 2011, it is unlikely that reference services will be sold in this access arrangement period. However, the forecast revenues resulting from the parameters proposed by the Commission would provide the service provider with the opportunity, if it were supplying the reference service, to earn a stream of revenue that would recover efficient costs associated with that service.

Cost allocation and tariff setting

NT Gas proposed to allocate total revenue across three pricing zones. While considered an improvement on postage stamp pricing, zonal tariffs still have the potential to create inefficient pricing signals. As noted in submissions, users located in zone three will be charged the same tariff regardless of whether they are in Katherine or Darwin.

The Commission is of the view that distance based tariffs are likely to provide better price signals to the market than ‘postage stamp’ or zonal tariffs. However, given that most customers are located at the end of the ABDP, the Commission considers that any loss in efficiency due to zonal pricing would be minimal. The Draft Decision seeks further comment from interested parties regarding the potential benefits and costs associated with distance based pricing.

Tariff path and incentive structure

Under the Commission proposed tariff path, for the year ending 30 June 2002, a customer in Zone Three would pay $1.90/GJ. This represents a reduction of approximately 45 per cent when compared to NT Gas’ proposal of $3.46/GJ.

The Draft Decision proposes that NT Gas’ tariff smoothing mechanism be amended. When determining the tariff path for the access arrangement period, the Commission prefers the use of a CPI-X approach. This approach, unlike NT Gas’, explicitly provides for the effect on tariffs due to actual changes in the CPI and removes the inflation risk inherent in NT Gas’ approach.

NT Gas proposed to introduce a rebate mechanism to share revenue from interruptible services according to the requirements of the Amadeus Gas Trust. The access arrangement does not indicate how this revenue is to be shared. The Draft Decision requires details of how revenues from the sale of interruptible services will be distributed to be included in the access arrangement.

Back haul tariffs/ trigger review

Given the potential of Timor Sea gas coming onshore, several interested parties have sought the inclusion of a back haul tariff. The Commission may require inclusion of back haul reference services if section 3.3 of the Code is satisfied. The Commission at this stage cannot conclusive state whether or not back haul services satisfy section 3.3 of the Code. The Commission has under the Code a number of options available. It could require the inclusion in the access arrangement of:

- a service description and a Reference Tariff for the back haul service;
- a trigger mechanism; or

- a statement of principles to apply to the calculation of tariffs for a back haul service.

The Draft Decision favours requiring NT Gas to incorporate in the access arrangement a trigger for early review if Timor Sea gas becomes available in the NT.

The Draft Decision requests submissions on a number of issues to assist the Commission in reaching a final position; such as whether it is likely that Timor Sea gas will come onshore and whether to include a trigger mechanism in the access arrangement.

Terms and Conditions

Gas quality specification

In the access arrangement, NT Gas included a gas quality specification. The Draft Decision requires NT Gas' access arrangement to be amended to ensure that any recommendation by the AGA Gas Quality Specification Working Group to adopt a more flexible gas specification can be reflected in the access arrangement for the ABDP.

Standard Service Agreement

NT Gas has not provided a standard service agreement. Further, NT Gas stated that the standard service agreement will be consistent with the access arrangement. The Draft Decision requires an amendment to the access arrangement to make it clear that in the event that any apparent inconsistency arises, Schedule 2 of the access arrangement which includes the terms and conditions, prevails over the standard service agreement.

Prudential Requirements

NT Gas proposed that users and prospective users must meet prudential requirements prior to the user requesting a service or being placed in a queue.

The Draft Decision proposes an amendment to require NT Gas to set out in the access arrangement the prudential requirements that will apply to users and prospective users.

Queuing Policy

NT Gas proposed in clause 6.4 of the access arrangement, that an existing user with a contractual right in force as at 25 June 1999 will, have pre-emptive rights over capacity reservation.

The Commission has examined the pre-existing contracts and has been unable at this stage to identify any provisions, which would be defined as an exclusivity right.

However, the Commission is concerned that the existing users' pre-emptive rights over capacity establishes a principle in the queuing policy where prospective users could be denied access to capacity. Such a principle has the potential to diminish competition in downstream markets in the future. Further, the Commission is concerned that clause

6.4 could become established in the access arrangement and, hence, form the basis of future access arrangements.

Consequently, the Draft Decision requires NT Gas to remove the fourth dot point of clause 6.4 of the access arrangement.

Extensions and expansions policy

The Commission is not satisfied at this stage that the extensions and expansions policy as it currently stands, is consistent with principles set out in section 2.24 of the Code.

The Draft Decision requires NT Gas to amend its proposed extensions and expansions policy to require it to obtain the Commission's consent before electing to omit new facilities (either extensions or expansions) from the covered pipeline.

Proposed amendments

The Commission proposes the following amendments to the access arrangement.

Proposed Amendment A2.1

In order for NT Gas' access arrangement for ABDP to be approved, the value of the initial capital base must be adjusted to the value derived by the Commission, **$176.2m** as at 1 July 2001.

Proposed Amendment A2.2

In order for NT Gas' access arrangement for the ABDP to be approved, clause 4 of section 4 of the access arrangement (the reference tariff policy) must state that new facilities investment that does not satisfy the requirements of section 8.16 of the Code may be undertaken by NT Gas. However, only that portion of the investment that satisfies section 8.16 of the Code may be included in the capital base.

In order for NT Gas' access arrangement for the ABDP to be approved, clause 6 of section 4 of the access arrangement must be amended to clearly specify that any new facilities investment must meet the requirements of section 8.16 of the Code before it can be included in the capital base.

Proposed Amendment A2.3

In order for NT Gas' access arrangement for the ABDP to be approved, the reference tariff policy must be amended to allow the Commission, at the commencement of the subsequent access arrangement period, to review, and if necessary adjust, the asset base for wholly or partially redundant assets, within the meaning of section 8.27 of the Code.

Proposed Amendment A2.4

In order for NT Gas' access arrangement for the ABDP to be approved, the depreciation schedule must be based on straight line accelerated depreciation of the Commission's initial capital base of $176.2m at 1 July 2001 (discussed in section 2.2.8) to a residual value of $61.84m at 1 July 2011.

Proposed Amendment A2.5

In order for NT Gas' access arrangement for the ABDP to be approved, for the purpose of calculating NT Gas' return on capital assets, the working capital component must not be included in the capital base.

Proposed Amendment A2.6

In order for NT Gas' access arrangement for ABDP to be approved:

- the WACC estimates and associated parameters forming part of the access arrangement must be amended to reflect the current financial market settings, by adopting the parameters set out by the Commission in Table 2.11 and Table 2.12; and
- the target revenues and forecast revenues must be based on these new parameters.

Proposed Amendment A2.7

In order for NT Gas' access arrangement for the ABDP to be approved, the ORC valuations for each zone used for the calculation of tariffs should be amended as follows:

Zone One	$147.2m
Zone Two	$100.1m
Zone Three	$75.0m

A breakdown of the ORC valuations for each Zone can be found in Appendix B of this Draft Decision.

Proposed Amendment A2.8

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas must amend the reference tariff proposed in Section 3 of the access arrangement. The amendment must have the effect that:

- the initial tariff (in 2001/02) is derived from the cost of service revenue resulting form the amendments proposed by the Commission in this Draft Decision; and
- in each subsequent year, the reference tariffs will be calculated using the CPI-X tariff escalator:

$$t_n = t_{n-1} \, (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X)$$

where X = 2.47 per cent.

Section 3 of the access arrangement must be amended to remove the reference to CPI adjustment of NT Gas' proposed reference tariff for the year to 30 June 2004. In the event that there is a gap between the reference tariff years specified in the access arrangement and the revisions commencement date, the interim reference tariff will be determined by adjusting the final year's reference tariff in accordance with the CPI-X methodology discussed in this amendment.

Proposed Amendment A2.9

In order for NT Gas' access arrangement for the ABDP to be approved, the access arrangement must be amended to include details of how revenue from interruptible services will be distributed.

Proposed Amendment A2.10

In order for NT Gas' access arrangement for the ABDP to be approved, the fixed principle (section 4.8) must be deleted.

Proposed Amendment A3.1

For the access arrangement to be approved, the Commission requires that NT Gas amend the access arrangement by defining, in response to the further process of public consultation, specific major events (if any) that would trigger an obligation on the service provider to submit revisions prior to the revisions submission date.

Proposed Amendment A3.2

In order for NT Gas' access arrangement for the ABDP to be approved, the access arrangement must be amended following any recommendations by the AGA Gas Quality Specifications Working Group to adopt more flexible gas specification in the Northern Territory.

Proposed Amendment A3.3

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas must clearly specify that schedule 2 of the access arrangement prevails over the standard service agreement.

Proposed Amendment A3.4

In order for NT Gas' access arrangement for the ABDP to be approved, the prudential requirements relevant for users and prospective users must be included in the access arrangement.

Proposed Amendment A3.5

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must remove the fourth dot point of clause 6.4.

Proposed amendment A3.6

In order for NT Gas's access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must specify in the access arrangement that it will seek the Commission's consent before electing to omit new facilities (either extensions or expansions) from the covered pipeline.

1. Introduction

On 25 June 1999 NT Gas Pty Limited submitted a proposed access arrangement and access arrangement information for the Amadeus Basin to Darwin Pipeline (ABDP) to the Australian Competition and Consumer Commission ('the Commission'), for approval under the *National Third Party Access Code for Natural Gas Pipeline Systems* ('the Code').

The access arrangement and access arrangement information describe the terms and conditions on which the company will make access to its pipeline available to third parties. The Commission has assessed the access arrangement and access arrangement information against the principles in the Code based on information provided by AGL Pipelines (NSW) Pty Limited (AGLP) and other interested parties.

This document sets out the Commission's Draft Decision and proposed amendments under section 2.13 of the Code for NT Gas' access arrangement.

This introduction includes:

- a description of the regulatory framework;
- a description of the Northern Territory (NT) gas industry structure;
- an outline of the ABDP access arrangement submitted for approval;
- a summary of the criteria for assessing an access arrangement under the Code;
- a summary of the consultative process undertaken as part of the Commission's assessment; and
- the Commission's Draft Decision, and an outline of the path to the Commission's final approval.

Chapter 2 of this Draft Decision considers the regulated rate of return and the initial capital base, which are required to determine reference tariffs for third party access. The reference tariff principles in section 8 of the Code are examined.

Chapter 3 provides an assessment of the access arrangements of the non-tariff mandatory elements in the Code.

Chapter 4 examines information provisions and performance indicators.

Chapter 5 sets out the Commission's Draft Decision. The Commission has identified amendments that would need to be made to the access arrangement in order for it to be approved. These proposed amendments are set out in the relevant sections of the Draft Decision and are brought together in the Executive Summary.

1.1 Regulatory framework

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

- the Code, under which transmission service providers are required to submit access arrangements to the Commission for approval;
- the *Gas Pipelines Access (South Australia) Act 1997*;[5] and
- the *Gas Pipelines Access (NT) Act 1998*.

Code Bodies and Appeals Bodies in NT with respect to transmission pipelines are:

- the Commission – Regulator and Arbitrator;[6]
- the National Competition Council – Code Advisory Body;
- the Commonwealth Minister – Coverage Decision Maker;
- the Federal Court – judicial review; and
- the Australian Competition Tribunal – administrative appeal.

The Commission is currently the relevant regulator with respect to gas transmission and distribution pipelines in the Northern Terriority.

1.2 The NT gas industry structure

1.2.1 Structure of the gas industry in the Northern Territory

Briefly, the gas industry in NT has the following key characteristics:

- There are two gas producers in the NT that access gas from the Amadeus Basin. Magellan operates the field at Palm Valley, and Santos operates the Mereenie field. The total amount of gas produced by these basins was 18.3 PJ in 1999.
- The gas transmission pipeline from the production points to the users is leased to and operated by NT Gas as trustee of the Amadeus Gas Trust. The Australian Gas Light Company (AGL) owns a 96 percent share of NT Gas. The subsidiary pipelines that service larger users are operated by NT Gas in association with other companies. Envestra and NT Gas operate the transmission pipeline from Palm Valley to Alice Springs and Power and Water Authority (PAWA) along with NT Gas operate the Macarthur River pipeline that services the large Macarthur River mine.

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5 South Australia acted as ‘lead legislator’ for the national gas access legislation.

6 The Commission is also Regulator and Arbitrator with respect of transmission pipelines in the other States and Territories with the exception of Western Australia.

- The gas produced in the NT is largely used for electricity generation. Of the 18.3 PJ produced, 13.6 PJ is used in electricity generation at Channel Island, Katherine and other power stations along the pipeline. Approximately 0.15 PJ goes to reticulation in urban areas such as Alice Springs, Katherine and other smaller towns along the pipeline. The remaining 4.5 PJ is used by major users such as the mines at Macarthur River and smaller industrial users in the Mataranka industrial region outside Darwin. Origin retails in Alice Spring and NT Gas Distribution retails in Darwin.

Section 2 of the Code specifies that the service provider is required to submit a proposed access arrangement (and associated access arrangement information) to the regulator for approval. The service provider is defined as 'a person who owns (whether legally or equitably) or operates the whole or any part of a Pipeline'. Ownership of the ABDP is vested in a consortium of banks.

Natural gas was first discovered at the Amadeus Basin, near Alice Springs, in both the Palm Valley and Mereenie fields during the mid 1960s. These discoveries, while significant, remained undeveloped due to the inaccessibility of markets for such remote reserves. In September 1983 gas for base load electricity generation was first produced and delivered to PAWA[7] at Alice Springs, 150kms from the Palm Valley gas field.[8]

In 1984 the NT Government began construction of a new coal fired power station on Channel Island some 42kms from the city of Darwin. During the course of constructing the power station, the NT Government, after conducting a feasibility study of the gas reserves in the Amadeus Basin and assessing the economics of hauling natural gas to Darwin via pipeline, committed both the Channel Island and Katherine power stations to be fuelled by natural gas.

NT Gas was formed from a consortium of companies to finance, construct, commission and operate the ABDP. The pipeline was commissioned in December 1986 and the first gas delivered to PAWA in January 1987.

In 1988 the AGL Group acquired through wholly owned subsidiaries[9] 96 percent of NT Gas, the other shareholders being Darnor Pty Limited (an NT Government company) (2.5 percent) and Centrecorp Aboriginal Investment Corporation Pty. Limited (a company owned by the Central Land Council) (1.5 percent).

Since the commissioning of the ABDP a number of lateral pipelines have been constructed to interconnect into the ABDP (none of which form part of the ABDP for the purposes of this access arrangement) including the:

- McArthur River pipeline which was commissioned in February 1995. The gas was supplied to fuel the power station at the McArthur River mine. This pipeline,

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7 Then known as the Northern Territory Electricity Commission.

8 Gas is delivered to Alice Springs through the Palm Valley to Alice Springs Pipeline which was recently sold by Holyman Limited to Envestra Limited.

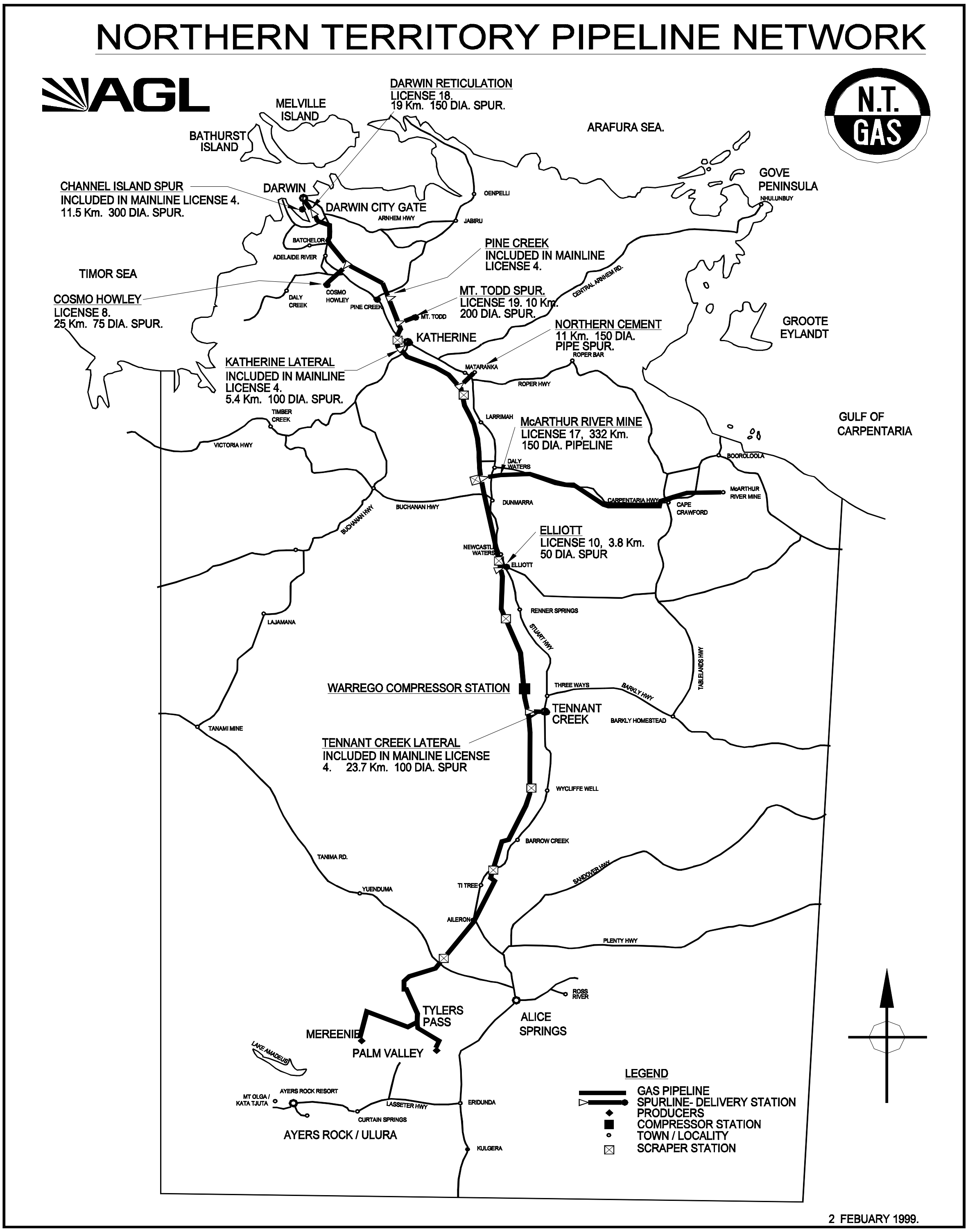
9 Agex Pty Limited and Sopic Pty Limited.

however, is currently not operating in its intended mode in that its operating pressure is restricted.

- Darwin City Gate to Berrimah pipeline. This was commissioned in January 1996 and gas was supplied to industrial users in Darwin in January 1996.
- Mt Todd pipeline which was commissioned in October 1996. The gas was supplied to fuel the power station at the Mt Todd mine. In November 1997 mining operations were suspended at the mine after the mine's owner Pegasus Gold Australia Pty Limited became insolvent, forcing the recently commissioned pipeline infrastructure out of service. The mining operation has very recently recommenced operation, but with lower demand for electricity than previously.

The location of the ABDP is illustrated in Figure 1 below.

Figure 1.1: Map of Amadeus Basin to Darwin Pipeline



Source: Access Arrangement Information, p. 53.

Current throughput of the ABDP is around 16 PJ per annum, with some 99.7 percent of total pipeline throughput being delivered to power generation facilities situated at various locations along the pipeline. Those facilities are either owned by PAWA or delivered to other such facilities on behalf of PAWA. The remaining pipeline throughput is to service small industrial customers in Darwin and industrial use at Mataranka.

There is currently no available firm capacity on the ABDP, with all existing capacity being utilised under existing agreements. There is in the vicinity of 5TJ per day of capacity available on an interruptible basis – the availability of such capacity depends on seasonal factors, reflecting that gas transported through the ABDP is primarily used for power generation.[10]

1.3 The assessment process

The proposed access arrangement and access arrangement information describe the terms and conditions on which NT Gas will make access to the ABDP available to third parties during the initial access arrangement period, which NT Gas proposes will last four and half years. However, under the provisions of the Code, NT Gas has the discretion to submit revisions earlier than the scheduled review.

The Commission's current assessment process relates to the initial access arrangement period.

Section 2 of the Code sets out the assessment process to be undertaken. The Commission is required to:

- inform interested parties that it has received the access arrangement from NT Gas;
- publish a notice in a national daily paper which at least describes the covered pipeline to which the access arrangement relates; state how copies of the documents may be obtained and request submissions by a date specified in the notice;
- after considering submissions received, issue a Draft Decision which either proposes to approve the access arrangement or not to approve the access arrangement and states the amendments (or nature of the amendments) which must be made to the access arrangement in order for the Commission to approve it. Submissions will be sought again following release of the Commission's Draft Decision;
- after considering any additional submissions, issue a final decision stating that it either approves or does not approve the access arrangement (or revised access arrangement) and the amendments (or nature of the amendments) that must be made to the access arrangement (or revised access arrangement) in order for the Commission to approve it; and
- if the amendments are satisfactorily incorporated in a revised access arrangement; issue a final approval. If not, the Commission must draft and approve its own access arrangement.

[10] Approximately 99.2 percent of gas sold in the NT is used for the generation of electricity, and approximately 84 percent of electricity consumed in the Territory is generated from gas (see ACCC Draft Decision on the Mereenie Gas Sales Agreement).

1.4 Criteria for assessing an access arrangement

The Commission may approve an access arrangement only if it is satisfied that it contains the elements and satisfies the principles set out in sections 3.1 to 3.20 of the Code, which are summarised below. An access arrangement cannot be rejected by a regulator solely on the basis that it does not address a matter that section 3 of the Code does not require it to address. Subject to this, the Commission has a broad discretion in accepting or opposing an access arrangement.

An access arrangement must include a policy on the service or services to be offered which includes a description of the service(s) to be offered. The policy must include one or more services that are likely to be sought by a significant part of the market and any service(s) which in the Commission's opinion should be included in the policy. To the extent practicable and reasonable, users and prospective users must be able to obtain those portions of the service(s) that they require, and the policy must also allow for a separate tariff for an element of a service if requested.

An access arrangement must also contain 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 service at the reference tariff. Tariffs must be determined according to the reference tariff principles in section 8 of the Code.

An access arrangement must include the following elements:

- **services policy** which must include a description of one or more services that the service provider will offer to users and prospective users;
- **reference tariffs and reference tariff policy**, including one or more reference tariffs. Tariffs must be determined according to the reference tariff principles in section 8 of the Code;
- **terms and conditions** on which the service provider will supply each reference service;
- a statement that the covered pipeline is either a contract carriage or market carriage pipeline (**capacity management policy**);
- 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/expansions policy** to determine the treatment of an extension or expansion of a pipeline under the Code;
- a date by which revisions to the access arrangement must be submitted; and
- a date by which the revisions are intended to commence.

In considering whether an access arrangement complies with the Code, the Commission must take into account, pursuant to section 2 of the Code:

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

1.4.1 Basis of assessment

The Commission considers that the unique leasing arrangement for the ABDP raises questions about how the pipeline should be assessed. The Commission accepts NT Gas' proposed approach that the Commission's assessment of the pipeline should be conducted under the assumption that NT Gas is the owner of the pipeline. The Commission considers that if the pipeline were assessed on the basis of the leasing arrangements alone, then regulated returns might not be consistent with the underlying investment decision.

1.5 Consultative process

Pursuant to the requirements of the Code, in August 1999 the Commission published a notice in a national newspaper and informed interested parties that it had received NT Gas' transmission access arrangement, and invited, received and considered submissions from interested parties.

In order to help foster the consultative process, the Commission released an *Issues Paper* in August 1999.

The Commission received written submissions from five interested parties regarding the proposed access arrangement (see Appendix A).

The major issues raised by interested parties in the submission included:

- valuation of the initial capital base;
- rate of return;
- depreciation;
- reference tariffs;

- terms and conditions, such as the gas specification; and
- other non-tariff elements such as the services policy, queuing policy and term and review policy.

Following receipt of NT Gas' access arrangement and access arrangement information on 25 June 1999, the Commission assessed the access arrangement information for compliance with the requirements of 2.6 and 2.7 of the Code. Pursuant to section 2.9(a) of the Code, the Commission determined that the access arrangement information did not satisfy those requirements, and decided to seek further information from NT Gas.

The Commission assessed the information provided by NT Gas in its entirety and concluded that the original access arrangement information, together with the additional information, satisfied the requirements of the Code with respect to the proposed access arrangement as it stood at that time. Changes proposed in this Draft Decision would, however be likely to result in a need for further revisions to the access arrangement information. Consequently, further assessment of the access arrangement information provided by NT Gas will be required prior to the final decision.

On 20 August 1999, the Commission issued a notice under section 41 of the Gas Pipelines Access Law on NT Gas for required information. This information included: the existing transportation contracts for the ABDP; a copy of the independent auditors' report of the asset valuation and electronic copy of all financial models used in developing the access arrangement information. In addition to issuing the section 41 notice, the Commission sought from NT Gas information on a number of issues including justification for NT Gas' proposed WACC of 11 per cent and accelerated depreciation of the regulatory asset base.

1.6 Review and expiry of the access arrangement

The Commission considered that NT Gas' proposed revisions submission date of four years and six months from the commencement of this access arrangement and its revisions commencement date:

- being six months after the revisions submission date; and
- the date on which the approval by the regulator of the revisions to the access arrangement takes effect under the Code;

was in accordance with the requirements of the Code.

Given that the access arrangement period will be five years from the date of final approval, the Commission determined revenues for the five-year period commencing 1 July 2001.

1.7 Draft decision to the Commission

The Commission has now made a Draft Decision under section 2.13(b) of the Code that it proposes not to approve the ABDP access arrangement in its current form. It has identified amendments to the proposed access arrangement that must be satisfactorily incorporated in a revised access arrangement in order for it to be approved (under section 2.16(c)). The proposed amendments are set out in the relevant sections in the Draft Decision and in the Executive Summary.

The Commission considers that the Draft Decision is likely to have a limited immediate impact for existing users, as the pipeline is fully contracted. However, it will be an important reference point for future negotiations concerning gas haulage services in the NT.

The Commission is now seeking submissions from interested parties on the Commission's Draft Decision on the ABDP access arrangement. All submissions must be delivered to the Commission by 8 June 2001 and should be addressed to:

> Ms Kanwaljit Kaur
> General Manager
> Regulatory Affairs - Gas
> Australian Competition and Consumer Commission
> PO Box 1199
> Dickson ACT 2602
>
> Fax: (02) 6243 1260

All submissions must be in writing, and preferably should also be supplied in electronic form (compatible with Microsoft Word 97 for Windows). They may be e-mailed to the project manager, Warwick Anderson, at 'warwick.anderson@accc.gov.au'.

Final decision

After considering submissions and the revised access arrangement (if submitted by the service provider), the Commission must issue a final decision (pursuant to section 2.16 of the Code) which:

(a) approves the access arrangement; or

(b) does not approve the access arrangement or revised access arrangement and provides reasons why it does not approve the (revised) access arrangement and states the amendments (or nature of the amendments) which would have to be made to the (revised) access arrangement in order for the Commission to approve it and the date by which a revised access arrangement must be submitted; or

(c) approves a revised access arrangement.

In the event that the Commission issues a final decision (pursuant to section 2.16(b) of the Code) which does not approve the access arrangement, the Code (sections 2.18-2.19) requires the service provider to submit a revised access arrangement to the Commission for consideration. However, if the service provider does not submit a revised access arrangement by the required date, or does so and the Commission is not satisfied that it incorporates amendments specified in the final decision, the Commission must draft and approve its own access arrangement (section 2.20 of the Code). Such a decision is subject to merits review by the Australian Competition Tribunal under the GPAL.

2. Reference tariff elements

The Code specifies a set of elements that an access arrangement must include. This chapter considers NT Gas' compliance with the principles to be followed in determining the reference tariff. Specifically, the chapter covers the calculation of NT Gas' revenue requirement, including the weighted average cost of capital (WACC), depreciation and initial capital base. Chapters 3 and 4 discuss NT Gas' compliance with the remaining elements of an access arrangement.

Sections 3.3 to 3.5 of the Code require an access arrangement to include a reference tariff for at least one service that is likely to be sought by a significant part of the market and other services for which the Commission considers a reference tariff should be included. An access arrangement must also include a policy describing the principles that are to be used to determine a reference tariff (a reference tariff policy). The reference tariff and reference tariff policy must comply with the reference tariff principles in section 8 of the Code.

In addition to the access arrangement and access arrangement information, NT Gas has provided the Commission with a spreadsheet file which contains the model used to construct the tariff from forecast volumes and cost data. This spreadsheet has not been made publicly available due to its commercially sensitive nature.

This chapter assesses NT Gas' reference tariff policy and proposed reference tariff using the structure below. The chapter identifies specific requirements of the Code, proposals by NT Gas, and submissions from interested parties under the following headings:

2.1 Reference tariff methodology

2.2 The initial capital base

2.3 New facilities investment and capital redundancy

2.4 Depreciation and inflation

2.5 Rate of return

2.6 Non-capital costs

2.7 Forecast revenue

2.8 Cost allocation and tariff setting

2.9 Tariff path and incentive structure

2.10 Assessment of reference tariffs.

2.1 Reference tariff methodology

Section 8 of the Code sets out the general objectives for a reference tariff and certain factors about which the relevant regulator must be satisfied before the regulator may approve reference tariffs and the reference tariff policy. The general principles are contained in sections 8.1 and 8.2 of the Code. Their application to NT Gas' proposed access arrangement are discussed in section 2.10 of this draft decision, after consideration of the parameters making up the revenue requirement and tariff.

Section 8.4 of the Code permits a choice of three methodologies for determining the total revenue:

- Cost of service: where total revenue is set to recover costs. These costs are calculated on the basis of:
  - — a return (rate of return) on the value of the capital 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 providing all services over 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 services (sections 8.30 and 8.31 of the Code).

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

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

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

NT Gas proposed a cost of service methodology.[11] This methodology is consistent with the Code.

As part of the access arrangement and access arrangement information, NT Gas proposed a three zone pricing scheme. NT Gas has advised the Commission that the

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[11] Access Arrangement Information, p. 5.

pipeline is currently fully contracted and there is no firm capacity available for third party access.[12]

2.2 The initial capital base

2.2.1 Code requirements

The Code requires the regulator to approve a value for an existing pipeline (an initial capital base) as part of the first access arrangement for that pipeline. This value carries over into subsequent access arrangement periods, subject to deduction of depreciation and redundant capital and addition of new facilities investment. The initial capital base will have a significant effect on the level of tariffs over a considerable period given the long life of assets, and a commensurate effect on the value of the business.

The principles for establishing the initial capital base of a pipeline system are set out in section 8 of the Code. These principles distinguish between pipeline systems that were in existence at the commencement of the Code (sections 8.10 and 8.11) and those that come into existence after the commencement of the Code (sections 8.12 and 8.13).

The initial capital base – existing pipelines

For existing pipelines, the Code states (section 8.11) that the value of the initial capital base normally should not fall outside the range of depreciated actual cost (DAC) and depreciated optimised replacement cost (DORC). In establishing the initial capital base, section 8.10 of the Code requires the regulator to consider:

- other well recognised asset valuation methodologies (section 8.10(c)) and the advantages and disadvantages of these methodologies (section 8.10(d));
- international best practice and the impact on the international competitiveness of energy consuming industries (section 8.10(e));
- the basis on which tariffs have been (or appear to have been) set in the past, the economic depreciation of the covered pipeline, and the historical returns to the service provider from the covered pipeline (section 8.10(f));
- the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code (section 8.10(g));
- the impact on the economically efficient utilisation of gas resources (section 8.10(h));
- the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a pipeline that may by-pass some or all of the pipeline in question) (section 8.10(i));
- the price paid for any asset recently purchased by the service provider and the circumstances of that purchase (section 8.10(j)); and

[12] Access Arrangement Information, pp. 2 & 5.

- any other matters considered relevant (section 8.10(k)).

General principles

In addition, the Commission is guided by the objectives for the design of a reference tariff and the reference tariff policy outlined in section 8.1 of the Code. These objectives are:

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

2.2.2 NT Gas' proposal

Consistent with section 8.10 (b) of the Code, NT Gas evaluated the initial capital base using the DORC methodology. NT Gas' reasons for selecting the DORC methodology over alternative asset valuation approaches included:

- the optimisation process allows technological benefits to be passed onto users while the cost of stranded/unutilised assets are not passed on;
- redundant or oversized assets are not included in the asset base, and therefore are not paid for by the users;
- DORC provides a consistent valuation between new and existing assets, regardless of past operating and accounting policies; and
- DORC sends correct price signals as to the cost of providing the service.

A number of key assumptions were adopted in the DORC evaluation, including:

- estimates of likely pipeline throughput were prepared for the 30-year period out to 2029 under three scenarios - a base, base reduced and a high case. The base reduced case assumes pipeline throughput peaks in 2015 before reducing by around 50 per cent by 2030, reflecting NT Gas' uncertainty as to future throughput.
- optimised replacement cost of pipeline and associated ancillary equipment assume 'brown-field' conditions given their geographical locations.
- materials and pipe sizes have been optimised to reflect the application of current industry design and construction practice.
- the optimum pipeline configuration is selected on the basis of the lowest NPV of the estimated capital and operating costs over the analysis period.

- depreciation has been applied to the ORC on a 'straight line' basis over the economic life of the assets comprising the ABDP. The economic life assumptions used by NT Gas are given in Table 2.1 below.

- the 'minimum remaining life' philosophy has been applied where appropriate.[13]

Table 2.1: Economic lives for the ABDP proposed by NT Gas

Asset	Economic Life (years)	Average Remaining Economic Life at 1 July 1999
Transmission Pipeline (coated and CP protected):		
Constructed 1986	80	67
Compressor Stations:		
Rotating Equipment	25	22
Station Facilities	35	32
Regulation and Metering Stations	50	37
Odorising Stations	35	22
SCADA	15	2

Source: Access Arrangement Information, p. 20.

Based on the assumptions detailed above, NT Gas calculated an Initial Capital Base (ICB) of $265.54m as at 1 July 1999. The results of NT Gas's DORC valuation are summarised in Table 2.2. The ORC valuation listed in the table is the optimum pipeline configuration required to transport the quantities in the base and high case scenarios. NT Gas stated that in light of the uncertainty over both ORC valuations (in that it is a theoretical exercise) and throughput estimates, the replacement cost of the existing pipeline configuration was considered the most appropriate basis upon which to determine the DORC valuation of the ABDP.[14]

[13] The 'minimum remaining life' philosophy assumes the asset always has a minimum value until it is replaced or abandoned. For all long lived pipeline assets the minimum remaining life was set at 5 years. All other assets were depreciated to zero over their economic lives.

[14] Access Arrangement Information, p. 11.

Table 2.2: NT Gas' proposed valuation of the initial capital base for the ABDP

Asset type	$ million (at 30 June 1999)[(a)]				
	RC[(b)]	**ORC[(c)]**	**Adjusted ORC [(d)]**	**Accum. Dep.**	**DORC**
Transmission pipeline	300.31	308.12	300.31	48.81	251.51
Compressor stations:					
Rotating equipment	2.00	6.00	2.00	0.23	1.77
Station facilities	5.00	10.00	5.00	0.41	4.59
Regulation and metering stations	9.78	9.78	9.78	2.48	7.30
Odourisation stations	0.25	0.25	0.25	0.09	0.16
SCADA and communications	1.62	1.62	1.62	1.40	0.22
Total asset value	318.96	335.77[(e)]	318.96	53.42	265.54

Source: Access Arrangement Information, p. 12.

Notes: (a) All cost information in the table is in 1999 dollars.
(b) The replacement cost (RC) of the current configuration.
(c) Pipe sizes optimised to reflect current industry design and construction practice and is the optimum pipeline configuration yielded from analysis based on the base and high case scenarios. Two optimised configurations were considered for the base reduced case throughput scenario, which resulted in a total replacement cost of $313.12m and $326.77m respectively.
(d) ORC has been adjusted to represent the replacement cost of the existing assets.

Consistent with the Code, NT Gas also valued the ICB using other commonly prescribed methodologies - Depreciated Actual Cost (DAC), residual value (based on economic depreciation) and Optimised Deprival Value (ODV).

Depreciated Actual Cost (DAC)

NT Gas calculated the DAC of the ABDP to be $234.7m. The methodology adopted by NT Gas to determine the DAC involved subtracting accumulated depreciation of the assets (charged on the basis of what NT Gas considered reasonable) from the total capital cost of the assets. Total capital cost included the actual capital cost of constructing the pipeline plus actual capital expenditure incurred since the pipeline was commissioned.

NT Gas acknowledged the difficulties in determining a DAC valuation for a leased asset where accumulated depreciation for statutory account purposes has not been previously calculated. In calculating the DAC, NT Gas assumed the asset was owned and operated by the same entity to date, depreciating it according to reasonable accounting standards.[15]

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15 Access Arrangement Information, p.12.

Residual Value (based on economic depreciation)

NT Gas undertook an analysis of the historical revenues and returns of the ABDP to determine whether there had been an under or over recovery of revenues. This required an estimation of the economic depreciation that has occurred on the ABDP since it was commissioned. NT Gas applied the following formula in estimating the economic depreciation for each year of operation:

Economic depreciation = revenue – operating costs – return on assets

Where economic depreciation is negative (an under-recovery of capital), this is added to the capital base to be recovered in later years. Where economic depreciation is positive, this is deducted from the capital base. Like the DAC calculation, NT Gas assumed actual capital costs at the time of commissioning and added actual capital expenditure since commissioning to arrive at the total capital cost of the assets. The return on assets was derived by applying a return equivalent to the long term bond rate in each year plus an additional risk premium of 2 per cent[16] to the capital base.

NT Gas stated that this analysis yields a value for the ABDP in excess of the DORC valuation, and suggested that the DORC methodology is the appropriate methodology for establishing the ICB. NT Gas' analysis also indicated that there was an under-recovery of revenue in every year since the ABDP was commissioned in 1986.[17]

Optimised Deprival Value (ODV)

The ODV methodology establishes the asset valuation as the lesser of the net present value (NPV) of the income that can be generated from the asset, and DORC. The ODV for the ABDP was calculated using the current income stream determined from existing contracts over a 30-year period, a residual value calculated under the 'perpetual method'[18] and a pre-tax real discount rate of 11 per cent. According to NT Gas' calculations, this provides an NPV valuation for the pipeline of $308.9m. NT Gas state that because this value is higher than the DORC asset valuation, the ODV valuation for the ABDP would be DORC.

Depreciation

As stated earlier, NT Gas applied depreciation to its ORC on a 'straight line' basis over the economic life of the assets comprising the ABDP to establish a DORC of $265.5m.[19] Specifically, pipeline assets were depreciated based on an 80-year life.

To recognise the risk of stranding faced by the ABDP, NT Gas then proposed to depreciate the pipeline assets using accelerated depreciation to a residual value of

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16 Agility letter to ACCC, 7 December 2000.

17 Access Arrangement Information, p.15.

18 The perpetual method calculates a residual by taking the each year's earnings before depreciation and dividing it by the discount rate.

19 Access Arrangement Information, p. 11.

$61.84m at 1 July 2011 and standard straight line depreciation thereafter until the end of the assets technical life in 2066.[20]

Agility's methodology for the calculation of DORC

Subsequent to NT Gas' original proposal, Agility on behalf of NT Gas, proposed an alternative methodology for constructing the DORC valuation from the estimated ORC. Broadly, Agility emphasised that the DORC derivation from ORC should be independent of the past or proposed frameworks for establishing tariffs. Instead, the value of the assets for regulatory purposes should be based on the NPV of revenues that could be generated by the assets over their remaining useful life as if tariffs were set on the basis of what would be charged by a new entrant in a contestable market.[21] As the new entrant would be constrained in a contestable market by the costs of other potential entrants the tariff and revenue profile over time would need to reflect the impact of changes in its costs, particularly replacement costs.[22] The outcome of applying this approach is that, for reasonable assumptions about the rate of technological change, the DORC value begins to deviate significantly from the ORC estimate only towards the end of the life of the asset.

According to Agility, the ratio of DORC to ORC for the ABDP was most likely to be in the range of 96 to 99 per cent. This would result in a DORC value of between $331m to $341m.[23] Agility's approach is concerned with establishing the value of DORC, which under the Code, is normally the upper limit of the value of the initial capital base. However, Agility acknowledges that the regulator must also take other factors into account when setting the value of the initial capital base.[24]

Following Agility's submission of its revised approach for the calculation of DORC the Commission questioned Agility whether the accelerated depreciation profile proposed by NT Gas had been considered in the context of Agility's new approach for calculating DORC. In response, Agility stated that the accelerated depreciation profile was not explicitly taken to account in the revised DORC calculation.

2.2.3 Submissions by interested parties

The majority of submissions received by the Commission focussed on the appropriateness of the proposed ICB. Woodside and Shell submitted that the proposed DORC value appeared too high. They also questioned the merits of using a DORC valuation because 'the economic theory does not produce a reasonable and/or

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20 Access Arrangement Information, p. 18.

21 *Construction of DORC from ORC*, Agility Management, August 2000.

22 If there were no cost changes over time, the revenue stream would take the form of an annuity. However, if there were technological changes taking place continuously there is likely to be a downward movement in revenues over time, at least in real terms. If costs (e.g. materials and construction) were increasing at a faster rate than inflation, revenues and tariffs could be expected to increase in real terms over time. Such modifications to annuities are sometime referred to as 'tilted annuities'.

23 Based on Venton & Associates re-assessment of ORC to $345m.

24 Section 8.10 of the Code.

acceptable competitive tariff' and 'incumbents are able to 'double dip' economic value'.[25]

Woodside and Shell further stated:

> A more realistic asset valuation would be somewhere in between DORC and depreciated value [DAC]. This would seem to be consistent with the realities of a competitive market place where the pricing point is never a precise formula driven number but rather, a market driven price, sitting somewhere in between the short term marginal cost and the long run economic average cost as determined by the mechanisms such as DORC. [26]

NT Power Generation (NTPG) also considered the DORC valuation to be too high and significantly influenced by the methodology used to determine accumulated depreciation of the pipeline asset. In particular, NTPG considered accumulated depreciation of $48.81m used in the DORC valuation to be much too low, and suggested that accumulated depreciation in the order of $92m[27] would be more appropriate. NTPG contended that this would correspond well with the $98.5m, which NT Gas considered to be a reasonable estimate of accumulated depreciation for the calculation of DAC.[28]

Furthermore, despite favouring DAC as the appropriate asset valuation methodology in this case, NTPG believed the $234.7m DAC valuation proposed by NT Gas was too high given that there was excess capacity on the pipeline at the time of commissioning.[29]

Nabalco also supported the use of DAC in establishing the ICB. In particular, Nabalco believed that the DORC methodology overvalues assets and does not accurately reflect the actual investment cost incurred.[30]

2.2.4 Desktop audit of DORC asset valuation

The Commission commissioned Connell Wagner Pty Ltd (Connell Wagner) to undertake a desktop audit of NT Gas' DORC valuation for the ABDP.

Connell Wagner report

Optimised Replacement Cost

Connell Wagner conducted its assessment using NT Gas' base case reduced throughput scenario (outlined above). The key findings of Connell Wagner's review of NT Gas' ORC valuation can be summarised as follows:[31]

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25 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p 3.

26 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p 3.

27 NTPG has calculated this using the 'unit of throughput' depreciation approach, and suggests accumulated depreciation of the ABDP facilities to date should be about 19% of original cost ($61.7m in 1986 dollars or $92m in 1999 dollars)

28 NTPG submission, p. 3.

29 NTPG submission, p. 3.

30 Nabalco submission, p. 2.

- NT Gas' proposed pipeline system design configurations do not represent the entire suite of pipeline configurations, some of which could potentially provide a lower ORC valuation.

- Unit costs for the pipeline should be $15,200 to $19,500 per inch per kilometre over the length of the ABDP, with the higher rates being appropriate for the more difficult sections requiring rock excavation and the remote southern sections beginning in Palm Valley and Mereenie.

- NT Gas assumed higher unit costs than Connell Wagner for the ABDP laterals. If the laterals were constructed at the same time as the mainline, then it is reasonable to use the same unit costs.

- NT Gas did not assume any cost difference for the installation of a second unit at a compressor station. Connell Wagner recommended that the cost of second and subsequent units installed at a compressor station should be calculated at 66 per cent of the installation cost of the first unit.

- The cost for meter stations was estimated by Connell Wagner to be $5m compared to AGL/NT Gas' valuation of $9.78m. The major reason for the disparity being differing estimates for the Channel Island Station.

- Provision for establishing maintenance support services for pipeline operations was not included in NT Gas' ORC estimate.

- NT Gas did not make sufficient allowances for native title compensation and interest during construction.

- Based on the documents reviewed, Connell Wagner was unable to establish the basis for load estimates assumed by ABDP and recommended that a better understanding of the forecast loads be sought by the ACCC.

- NT Gas did not optimise any of the ABDP's laterals. However, lateral optimisation is unlikely to have a material impact on the ORC valuation.

- Based on available information Connell Wagner was not able to confirm AGL's stated ±10 per cent cost estimating accuracy. It was Connell Wagner's view that the level of disaggregation proposed by NT Gas was likely to provide a cost estimate accuracy of ±25 per cent at best.

- Connell Wagner considered an assessment term of 15 years (compared to NT Gas' 30 year term) more reasonable for flow forecasts and the NPV analysis of pipeline system costs.

Connell Wagner estimated an ORC of $308m, around 3 per cent lower than NT Gas' existing system ORC of $319m. Without further information and more detailed

[31] Connell Wagner Pty Ltd, 'Review of NT Gas' DORC Valuation for the Amadeus Basin to Darwin Pipeline' *Draft Report*, May 2000.

assessment of the ABDP, the order of accuracy of Connell Wagner's estimates was within the range of -5 to +15 per cent, with 75 per cent confidence.

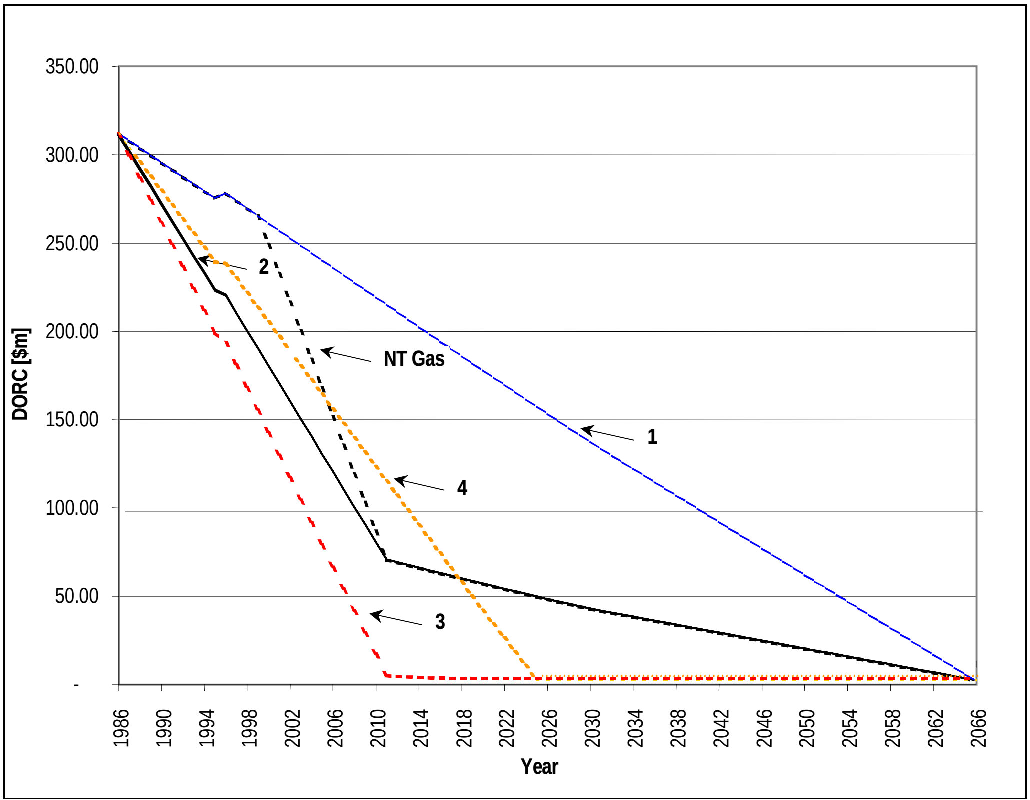
Depreciated Optimised Replacement Cost

Connell Wagner questioned NT Gas' approach to depreciating ORC. Connell Wagner disagreed with NT Gas' approach to using a technical life of 80 years to derive its proposed DORC from ORC and then applying accelerated depreciation based on a residual value of $61.84m in 2011. Connell Wagner put forward four possible scenarios for depreciating the ORC value to arrive at the DORC. The four scenarios were described as follows:

- *Scenario 1* – standard straight-line depreciation over the technical life of the pipeline;
- *Scenario 2* – accelerated depreciation from pipeline commissioning to 2011, and thereafter standard straight-line depreciation over the remaining technical life of the pipeline – this option retains the residual asset value of $61.84m (at 1 July 2011) recommended by NT Gas;
- *Scenario 3* – accelerated depreciation from pipeline commissioning to 2011, reflecting an expectation that the pipeline will not be utilised post 2011; and
- *Scenario 4* – accelerated depreciation from commissioning to 2025, reflecting an expectation that the Amadeus Basin gas fields will be depleted by 2025.

These four scenarios, along with NT Gas' approach, are shown in Figure 2.1.

Figure 2.1: DORC valuation of the ABDP



Source: Connell Wagner, Review of NT Gas' DORC valuation for the ABDP, p. 38.

Based on these four scenarios, Connell Wagner considered that the DORC valuation (as at 1 July 1999) for the ABDP would be likely to fall within the range $155m to $214m (Scenario 3 and Scenario 4 respectively).

Connell Wagner recommended the depreciation approach identified by Scenario 2. In making this recommendation Connell Wagner pointed out that the redundancy risks highlighted by NT Gas may have existed since the initial planning, construction and operation of the pipeline and therefore, depreciation based on an 80-year life may not be appropriate. In view of the limited reserves of the Amadeus Basin, it would be reasonable to expect that pipeline tariffs would be geared to recoup the costs of the assets over a shorter time period.. Connell Wagner also noted that while Timor Sea gas and the depletion of the Amadeus Basin is likely to displace northward haulage through the ABDP, it is likely that the pipeline will still provide some back haulage services until the expiration of its technical life. Connell Wagner considered that Scenario 2 reflected the commercial possibilities of the foundation customer contract expiring in 2011 and also the potential usage of the pipeline upon entry of Timor Sea gas.

Connell Wagner used its own asset life assumptions,[32] ORC estimate and the depreciation approach outlined in Scenario 2to calculate a DORC value for the ABDP of $191m.

[32] Technical lives assumptions for pipeline assets, rotating equipment, metering equipment and other pipeline facilities (including SCADA) were 70,30, 50 and 15 years respectively.

Depreciated Actual Cost

The Commission also requested Connell Wagner to calculate a DAC for the ABDP using accepted accounting asset lives. In the absence of adequate data, Connell Wagner chose to determine a reasonable range for the DAC valuation.[33] Connell Wagner proposed a range of $145m to $211 as the likely DAC value of the ABDP. This range was established by examining two different possibilities for depreciating the initial cost of the assets:

- Assuming that NT Gas structured tariffs to recuperate all pipeline capital by 2011 (the expiration date of the foundation customer contract) the DAC as at 1 July 1999 was $145m.
- Assuming that NT Gas structured tariffs to recuperate all pipeline capital by 2025 (the expected depletion date for gas reserves in the Amadeus Basin) the DAC as at 1 July 1999 was $211m.

2.2.5 NT Gas' response to the Connell Wagner report

Venton & Associates review of the Connell Wagner report

NT Gas was provided with a copy of Connell Wagner's draft report for comment.[34] Venton & Associates (Venton) was engaged by NT Gas to provide comments on the technical and cost estimate matters in the Connell Wagner report.

The Venton report identified a number of areas where it believed the Connell Wagner optimised design was deficient, including:[35]

- non commercial pipe steel grade and inadequate pipe wall thickness selection;
- an apparent over-optimistic hydraulic performance of the pipeline resulting in fewer initial compressor stations being installed than are actually required;
- estimating unit costs that appear lower than industry norms for the size proposed;
- estimated costs for compressor stations and meter regulating stations that are lower than current development costs for similar installations in Australia.

Venton also reassessed NT Gas' ORC estimate to account for interest during construction, native title costs and inconsistencies in compressor station costs – areas identified by Connell Wagner as missing or overlooked by NT Gas. The allowance for native title and cultural heritage costs was estimated by Venton to be approximately $10m.[36]

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[33] The actual cost assumed was $329 million. This is an average actual cost based on the capital additions and asset disposals from 1986 to 1999.

[34] Connell Wagner's final report did not differ substantially from its draft report.

[35] Venton & Associates, *NT Gas DORC Review of Connell Wagner ACCC Submission*, 5 September 2000, p 1.

[36] Venton & Associates, *NT Gas DORC Review of Connell Wagner ACCC Submission*, 5 September 2000, p 6.

In its report, Venton stated that when allowances were made to both the Connell Wagner and NT Gas estimates to include these omissions or deficiencies,[37] the estimated cost of each 'optimised' design increased substantially. Connell Wagner's optimised cost increased from $308m to $351m[38] and NT Gas' optimised cost (replacing the existing system) was increased from $319 to $345.

Venton also responded to Connell Wagner's suggestion that the accuracy of the NT Gas and the Connell Wagner estimates was ±25 per cent.[39] They argued that if this error level is correct, then each estimate lies within the error band of the other, and hence it is wrong to draw a conclusion that one design is optimal compared to another.

2.2.6 Connell Wagner's response to the Venton & Associates report

After reviewing Venton's comments in response to its desktop audit of the initial capital base, Connell Wagner submitted a number of comments to the Commission to address the key areas of discrepancy between Venton and Connell Wagner.[40] Connell Wagner dismissed the majority of Venton's criticisms.

- In accordance with the Commission's terms of reference, Connell Wagner utilised the base case scenario gas flow forecast. Therefore, the design gas flow used for consideration by Connell Wagner in its report and the resulting optimum design were based on different assumptions than that used by Venton in its analysis of NT Gas' modelling.[41] Connell Wagner's ORC of $308.4m is approximately $10.5m below that of NT Gas' estimated ORC of $318.9m.

- Connell Wagner stated that Venton appeared to have assumed that Connell Wagner used a conceptual design for compressor stations assuming three compressor units. Venton proposed a total of $20.4m be added to Connell Wagner's cost estimate for the compressor stations. However, Venton did state that if the Connell Wagner compressor installation schedule were correct then this would be reduced to $6.4m.[42] Connell Wagner stated that it had not made provisions for more than two compressor units at any location and considered its original cost estimate for each compressor station to be reasonable.[43] Modelling undertaken by Connell Wagner indicated that two compressor stations were more than sufficient.

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37 No adjustment was made for 'unit' construction cost differences.

38 Venton & Associates note that if no adjustment is made to the Connell Wagner compressor installation schedule, their estimated cost would increase to $337.

39 Venton comments were based on Connell Wagner's draft report which estimated an accuracy level of ±25%. This estimate was later refined in the final report to –5+15% with 75% confidence.

40 Connell Wagner letter to Commission, 29 November 2000.

41 NT Gas' ORC estimate was based on the optimal design for the high and base case throughput scenarios.

42 Venton & Associates, *NT Gas DORC Review of Connell Wagner ACCC Submission*, 5 September 2000, p 7.

43 Connell Wagner valued the first compressor at $6.5m and the additional compressor at $4.3m.

- Connell Wagner's design grade of steel could be considered as non-standard but still acceptable under the API 5L Specification for Line Pipe.

- The wall thickness for the Channel Island extension may need to be increased. The cost difference between Connell Wagner's assumed wall thickness and Venton's was $250,000.

- Connell Wagner agreed with Venton that if a second compressor unit was added after the station was completed, the cost would be higher. However, Connell Wagner assumed that both compressor units would be installed at the same time. The second compressor unit rate should not be equal to the first unit, as infrastructure costs are included in the unit rate for the first compressor.

- While there is no reason to believe the Venton allowance for native title compensation payments is wrong, Connell Wagner recommend that historical (actual) compensation payments be considered as the most appropriate guide in this instance. In the absence of this information Connell Wagner estimated a native title allowance of $5m, compared to Venton's $10m.

- Venton commented that the discount project cost analysis carried out by Connell Wagner was superficial. Connell Wagner considered Venton's remarks to be irrelevant as all of the modelling employed, parameters used and options considered by Connell Wagner in its analysis had not been available to Venton.[44]

2.2.7 Commission's considerations

Section 8.10 of the Code suggests a range of valuation approaches that should be considered when establishing the initial capital base for an existing pipeline. In this Draft Decision the Commission has assessed the ORC of the ABDP's assets and depreciated to determine a DORC valuation. In addition, the Commission has considered alternative valuation methodologies including DAC, residual value (based on economic depreciation), book value and sale price to establish an initial capital base valuation for the ABDP consistent with the principles set out in the Code.

In its analysis, the Commission has considered the information contained in NT Gas' access arrangement information and NT Gas' response to the Commission's Section 41 Notice.[45] The Commission has also considered the Connell Wagner report on the DORC valuation for ABDP, the Venton review of the Connell Wagner report, Connell Wagner's response to the Venton report and Agility's revised approach to the construction of DORC from ORC.

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44 Connell Wagner letter to Commission, 29 November 2000, p. 4.

45 On 20 August 1999, the Commission issued a notice under section 41 of the Gas Pipelines Access Law on NT Gas for required information. This information included: the existing transportation contracts for the ABDP; a copy of the independent auditors' report of the asset valuation and electronic copy of all financial models used in developing the access arrangement information.

Optimised replacement cost

In its access arrangement, NT Gas expressed considerable uncertainty about estimates of pipeline throughput for the 30-year period to 2029. This is due to the expiration of its foundation contract in 2011 and a lack of information regarding future production expectations of the existing Amadeus Basin fields.[46] In light of the uncertainty over ORC valuations (in that it is a theoretical exercise) and throughput estimates over the 30-year period, NT Gas nominated its estimated replacement cost of $318.96m as the appropriate ORC valuation for the ABDP.

In addition to engaging Connell Wagner to review NT Gas' ORC, the Commission also conducted its own in house assessment. Although its ORC was derived independently from the other analysis, the Commission obtained an optimal configuration almost identical to that of Connell Wagner's. On the other hand, despite starting with similar assumptions on the appropriate demand scenario, NT Gas determined a different optimal configuration. Comparisons of the various optimal configurations are provided in Table 2.3.

Table 2.3: ABDP pipeline: comparison of optimum designs

			NT Gas	Connell Wagner	ACCC
Mereenie to Tylers Pass	Diameter	mm	273		
116 km	wall thickness	mm	4.8	4.5	
	Grade	API 5L	X60	X75	X80
	MAOP	kPa	10,200		
Palm Valley to Tylers Pass	Diameter	mm	356	219	
48 km	wall thickness	mm	5.8	4.5	
	Grade	API 5L	X60	X75	X70
	MAOP	kPa	9,650		
Tylers Pass to Mataranka	Diameter	mm	356	273	
1,062 km	wall thickness	mm	5.8	5.62	5.3
	Grade	API 5L	X60	X75	X80
	MAOP	kPa	9,650	15,300	
Mataranka to Darwin	Diameter	mm	324	273	
391 km	wall thickness	mm	5.25	5.62	5.3
	Grade	API 5L	X60	X75	X80
	MAOP	kPa	9,650	15,300	
Channel Island extension	Diameter	mm	324	273	
12 km	wall thickness	mm	7.92	4.5	
	Grade	API 5L	X60	X75	X80
	MAOP	kPa	9,650	6,950	
Laterals	Diameter	mm	114		
29 km					
km x mm			559,596	445,431	
Number of compressor sites/units	in first year		1/1	2/2	
Compressor power		kW	1,200		

[46] Access Arrangement Information, p. 18.

In its ORC analysis NT Gas considered three different demand scenarios when determining the appropriate valuation for the ABDP– a base, base reduced and a high case. NT Gas' calculated its ORC value of $335m based on the optimal configuration obtained from both the high and base case scenarios. However, the Commission considers the base reduced case scenario a more appropriate basis for determining the ORC valuation for the ABDP. NT Gas' uncertainty about future pipeline throughput supports the view that the most likely demand scenario is represented by the base reduced case. NT Gas' own ORC calculations using the base reduced case yielded an optimal configuration valued at $313m, which is lower than its proposed existing system ORC of $318.96m.

The Commission concurs with Connell Wagner's view that an assessment term of 15 years, compared to NT Gas' 30 year term, is a more reasonable time frame for the NPV analysis of pipeline system costs. A similar 15-year time horizon was proposed by EAPL in its evaluation of the ORC for the Moomba to Sydney pipeline (MSP) system.[47] The Commission therefore adopted the more conservative time horizon of 15 years in its analysis.

Based on its own optimal configuration, the Commission has calculated an ORC of $322m (at 1 July 1999) for the ABDP. A comparison of the different ORC valuations can be seen in Table 2.4.

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47 ACCC, Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System, *Draft Decision*, 19 December 2000, p. 18.

Table 2.4: Comparison of ORC valuations

Cost in $m 30 June 1999	NT Gas proposed	NT Gas adjusted by Venton	Connell Wagner	Connell Wagner adjusted by Venton	ACCC Draft Decision
Transmission pipelines	300.3	300.3	257.4	262.9	256.4
Compressors	7.0	9.5	21.6	28.0	20.8
Regulating, metering, odourisation	10.0	11.0	5.0	10.7	7.0
SCADA and communications	1.6	1.6	0.7	0.7	4.7
Linepack	0.0	0.0	0.0	0.0	0.0
Operations facilities	0.0	0.0	6.7	6.7	8.3
Native title allowance	0.0	10.0	5.0	10.0	8.3
Sub-total	393.3	460.8	452.4	543.4	501.9
Interest during construction	0.0	12.0	12.1	12.1	16.8
Total	**318.9**	**344.4**	**308.5**	**331.1**	**322.3**
km x mm	559,596	559,596	445,431	445,431	445,431
Weighted average unit cost on total $/km.mm	0.0	0.0	0.0	0.0	723.6

It appears that in its ORC valuation, NT Gas has either not shown or omitted separate allowances for native title, operations and maintenance facilities of a capital nature and interest during construction. It is unclear whether such allowances have actually been provided for by NT Gas or whether they were included under other headings.

Detailed estimates, provided to the Commission by NT Gas on a confidential basis, show that a general contingency, typically amounting to 10 per cent of the total, has been included for each main pipeline segment. While the inclusion of such an allowance might be justified under certain circumstances (for example, when budgeting for a new project to place a cap on the total cost), it is not considered appropriate in a regulatory sense for determining the replacement cost of an existing pipeline.

However, NT Gas may have considered the general contingency a sufficient provision to cover allowances for native title and interest during construction, although this has not been stated. The most recent Venton review, commissioned by NT Gas, has made what it regards as an appropriate adjustment for native title and interest during construction (all adjustments proposed by Venton are shown in separate columns in the table above). The Venton review does not provide reasons for such adjustments other than to assume they have been overlooked in NT Gas' detailed costing. The Connell Wagner report makes a similar assumption.

Venton's total proposed adjustment for these two possible significant omissions in the NT Gas estimate is $22m. Coincidentally, the total of the general contingency amounts shown in NT Gas' detailed costing of its replacement option is $23m, so the net effect of any decision by the Commission to disallow the general contingency but to allow adjustment for native title and interest during construction has little effect on the total cost.

In any event, as can be seen, the Commission's ORC of $322m, which includes estimates for the items discussed above is $3m more than that proposed by NT Gas. Based on its own analysis, the Commission proposes to adopt an ORC of $322m.

Consideration of Agility's DORC proposal

As discussed earlier, Agility on behalf of NT Gas, proposed an alternative methodology for constructing the DORC valuation from the estimated ORC. A detailed analysis of Agility's approach to the construction of ORC from DORC was provided in the Commission's *Draft Decision* on EAPL's access arrangement for the MSP.[48] Essentially, the Commission does not consider Agility's proposed methodology to be appropriate for regulated gas assets for two main reasons:

- it is inconsistent with the depreciation proposed in the regulatory framework and the historical treatment of depreciation for the purpose of setting tariffs. It therefore loses its relevance for setting an initial capital base which needs to comply with fairness requirements of the Code, (sections 8.10(f) and (g) in particular); and

- the hypothetical contestable model used to establish the revenue profiles of new and existing assets has limited relevance to the regulated gas pipeline industry where prices are established on the basis of straight line depreciation.

Depreciation

Section 8.33 of the Code gives guidance on the depreciation schedule for regulatory purposes. The depreciation schedule for each asset or group of assets should be designed so that, to the maximum extent that is reasonable, it is adjusted over the life of the asset or group of assets to reflect changes in the expected economic life of the asset or group of assets. In depreciating the ORC to arrive at a DORC valuation for a pipeline system, the Commission favours depreciation by asset class.

The Draft Regulatory Principles interprets DORC as the price that a firm with a certain service requirement would be prepared to pay for 'second-hand' assets with their remaining service potential, given the alternative of installing new assets. That is, existing assets, with 'old' technology and higher operating costs, compared to new assets, which embody the latest technology, generally have lower operating costs, and hold greater remaining service potential.

NT Gas has depreciated its ORC on a straight-line basis over the economic life of the assets comprising the ABDP to establish a DORC of $265m at 1 July 1999. More specifically, pipeline assets, which constitute a significant portion of the ABDP's ORC

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48 For a more detailed discussion of the Commission's assessment see: ACCC, Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System, *Draft Decision*, 19 December 2000, pp. 25-29.

valuation, have been depreciated based on an 80-year life (that is, a remaining life of 67 years).

NT Gas' use of technical lives to depreciate ORC represents the traditional approach to calculating a DORC valuation, that is, DORC is given by ORC times the proportion of the remaining life of existing assets relative to the technical life of new assets. NT Gas' .approach assumes that the technical life and economic life of the assets correspond. Using the Commission's ORC and NT Gas' approach to depreciation, the DORC for the ABDP would be $267.2m.

However, the Commission considers that the DORC valuation, as calculated by NT Gas, does not provide an appropriate valuation of the ABDP's pipeline assets. It is the Commission's view that the risk of stranding currently faced by the pipeline was evident during the construction of the pipeline. The evidence of this risk leads the Commission to believe that the appropriate valuation for the ABDP's pipeline assets lies below that established by NT Gas' proposed DORC.

NT Gas submitted in its access arrangement information that the residual value of the pipeline on 1 July 2011 will be $61.84m.[49] NT Gas provided the Commission with information on a confidential basis to support this value. Based on the evidence provided, the Commission is satisfied that $61.84m is an appropriate estimate of the residual value of the ABDP in 2011. In addition, the Commission has reason to believe that the residual value was established prior to the pipeline being commissioned. Further, the Commission considers that two key factors also support this residual value.

First, as discussed later in section 2.4.4, according to the NT Government and PAWA, the proven probable reserves for the Amadeus Basin are only expected to be able to meet the Northern Territory's demand for gas until 2015.[50] Confidential consultants' reports provided to the Commission indicate that there have been several downward reassessments of the production expectations of the Palm Valley field since the pipeline was commissioned. Therefore, it would appear that the diminished supply capacity of the Palm Valley gas reserves and the uncertainty regarding the availability of future reserves has been known for a number of years.

Second, NT Gas' major foundation contract is expected to expire in 2011. Based on the gas sales agreements, submitted by NT Gas to the Commission on a confidential basis, the expiration date of the original contract was extended to 2011 in 1995.[51]

Given the above information, the Commission is of the view that the ABDP has been facing a risk of stranding since it was commissioned in 1986. Specifically, the existence of the 2011 residual value of $61.84m prior to 1999 leads the Commission to believe that the earning potential of the ABDP was expected to be significantly reduced by 2011. The expiration date of the foundation contract combined with the increasing

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[49] Access Arrangement Information, p. 18.

[50] NT and PAWA submission, 17 November 1999, p. 3.

[51] Gas Sales Agreement between the Northern Territory Electricity Commission and NT Gas, and Gas Sales Agreement – Amended Agreement between PAWA and NT Gas.

uncertainty regarding remaining accessible reserves in the Amadeus Basin further supports the Commission's view.

It is therefore difficult to accept that NT Gas, as a prudent investor, would not recognise the likelihood of stranding earlier and structure its tariffs accordingly. NT Gas' proposed approach seeks to gain the advantage of a rate of return on a high asset base, as well as a generous depreciation allowance.

After consideration of the factors given above and other confidential information, the Commission has determined an initial capital base (before adjusting for deferred tax liability) of $198.8m for the ABDP as at 1 July 1999. To calculate its initial capital base the Commission depreciated ORC on the following basis:

- pipeline assets were depreciated (straight line) based on the residual value of $61.84m at 1 July 201l, assuming that 13 years of the asset's life has already expired.

- all other asset classes were depreciated (straight line) based on their remaining economic lives (discussed in the following section)

The Commission considers that its initial capital base valuation represents a more appropriate value for the ABDP's assets in light of the risk of stranding apparent on the pipeline.

Further, the Commission believes that its initial capital base valuation is consistent with an estimate of the 'second hand' value of the service provider's assets. In this case, a new investor is unlikely to pay the DORC value proposed by NT Gas if the potential future revenue streams are substantially reduced due to the risk of stranding in 2011.

Sections 8.10 (f) and (g) of the Code provide for the regulator to give consideration to the basis upon which tariffs have been (or appear to have been) set in the past, historical returns and the reasonable expectations of persons under the regulatory regime that applied prior to the Code.

To further substantiate its assessment of past depreciation the Commission has also undertaken a detailed analysis of confidential information supplied by NT Gas (including information relevant to section 8.10 (f) and (g) of the Code). An analysis of this confidential information has been provided to NT Gas in a confidential appendix to this Draft Decision. The analysis supports the Commission's view that its initial capital base is consistent with section 8.10 (f) and (g) of the Code.

Effective asset life

As mentioned above, section 8.33(b) of the Code states that an asset forming part of the covered pipeline should be depreciated over its economic life. A pipeline's economic life may differ substantially from its technical life if there are factors other than the condition of the pipeline that limit its usefulness. The outcome of taking economic life into account should be greater correspondence between the return of capital and the utility of the asset in producing regulated revenues for the entity.

A decrease in gas reserves has the potential to limit the remaining economic life of the pipeline. The Commission understands that advisers to the Victorian transmission systems owner took this factor into account in arriving at depreciated values (pre-privatisation) for the pipeline systems in that State.

Typically the threat of stranding would be reflected in a reduced economic asset life. However, NT Gas' proposed accelerated depreciation (over 12 years from 1999 to 2011) for the pipeline assets while maintaining its remaining economic life at 67 years. The economic lives assumed by NT Gas were set out earlier in Table 2.1.The asset life assumptions used by NT Gas suggest that throughput is expected to drop significantly after 2011, but the ABDP will continue to be used until the end of its technical life.

Although NT Gas' foundation contract expires in 2011 and continuation of the status quo appears unlikely, there is still the potential for smaller quantities of gas to be transported on the pipeline and a possibility that it may be used to back haul Timor Sea gas from Darwin. The likelihood of such circumstances leads the Commission to believe that the pipeline will continue to hold some, albeit limited, economic value after 2011. This implies that the economic life of the asset will not expire until much later.

The Commission has therefore adopted the asset lives proposed by NT Gas in its analysis. However, the Commission will review this matter in subsequent access arrangements, once more information is available on the future use of the pipeline.

DAC, book value, residual value based on economic depreciation and sale price

Section 8.10 of the Code states that in addition to the DORC, the depreciated actual cost (DAC) and other well-recognised asset valuation methodologies should be considered in establishing the initial capital base.

NT Gas calculated a DAC of $234.7m for the ABDP. Because the ADBP is a leased asset NT Gas has not been obliged to calculate accumulated depreciation for statutory accounting purposes. Therefore, the DAC proposed by NT Gas is essentially an estimate, calculated on the basis of 'reasonable accounting standards.' No indication of the asset life assumptions used to calculate the accumulated depreciation was given by NT Gas.

As discussed earlier, Connell Wagner was also asked by the Commission to calculate a reasonable DAC for the ABDP. Connell Wagner's analysis provided a range of $145m to $211m for the DAC based on the assumption that NT Gas structured its tariffs to recuperate all pipeline capital by 2011 and 2025, respectively. Utilising the same methodology as Connell Wagner, the Commission also calculated a DAC for the ADBP assuming accelerated depreciation from 1986 to a residual value of $61.84m in 2011.[52] This analysis provided a DAC for the ABDP of $179.5m at 1 July 1999.

Previously, the Commission has considered the book value and residual value (based on economic depreciation) useful guides in assessing the appropriateness of the initial capital base determined under DORC. In this case however, the extended time frame

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[52] This approach utilised the same assumptions regarding depreciation as outline in Connell Wagner's Scenario 2. That is, depreciation was calculated in the same manner as DORC based on a residual value of $81.64m, but using the average actual cost of $329m as opposed to the ORC.

over which the residual value and book values were calculated resulted in valuations well in excess of the DORC (both that calculated by NT Gas and the Commission).

In the absence of reliable data, any estimate of either residual value or book value is likely to be subject to some margin of error. While this error margin may be small when calculating the initial valuation, the margin is compounded with each subsequent valuation (which inherently contains its own margin of error). Therefore, the longer the period over which the residual value or book value is calculated, the greater the likelihood that the estimated valuation will be subject to substantial error. In the case of NT Gas, this error margin would be significant because of high inflation and interest rates between 1986 and 1990. Therefore, the Commission does not consider book value and residual value to be useful guides in establishing the initial capital base for the ABDP.

An example of where residual value and book value can provide a useful guide in setting the initial capital base was the Commission's assessment of the initial capital base for Epic Energy's Moomba to Adelaide Pipeline System (MAPS). In that instance, the assets had recently been transferred and the book and residual values calculated were very similar to the DORC valuation.[53]

Notwithstanding the Commission's views on the appropriateness of calculating the residual value and book value calculations over an extended period of time, section 8.11 of the Code states that the initial capital base valuation should not fall outside the range of values determined by DAC and DORC. In this instance, both the residual value and book value calculated by the Commission were in excess of DORC. Consequently, neither can be used to establish the initial capital base.

In previous access arrangements, the Commission has also relied upon recent sale price as a guide or check on the current value of the pipeline's assets. In theory a purchaser would pay an amount up to the net present value of future earnings expected from the assets. The Commission requested NT Gas to provide it with the price paid by AGL in 1988 for its 96 per cent share in NT Gas. Agility responded on behalf of NT Gas, stating that providing the information would involve a significant amount of time and cost and that the sale price would not provide any meaningful information as to the value of the pipeline at the time of AGL's share acquisition.[54] The Commission does not accept this view and considers that it is necessary to examine the sale price to determine whether it does provide meaningful information.

Deferred tax liability

The ICB valuation is intended to reflect the valuation the business would place on its assets at the time the business is subjected to the regulatory framework.[55] A major objective of the first review is to establish a regulatory framework which allows

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53 ACCC, 'Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System', *Draft Decision*, 16 August 2000, p. 20.

54 Agility letter to ACCC, 23 February 2001.

55 Conceptually this is the maximum value the business would be willing to pay for the existing assets rather than build a new optimised pipeline to provide the same level of service and normally corresponds to its DORC valuation.

regulated tariffs and expected revenues to sustain that valuation. This is why the expected rate of return is set at a commercial level commensurate with the business risks involved. The objective requires that the returns underwrite neither a higher or lower valuation. It is important therefore to consider how the regulatory framework itself may effect the commercial valuation of the assets in the hands of the business and hence, make appropriate adjustments to the ICB.

One important aspect of the post-tax framework is that expected tax liabilities are compensated for directly in regulated cash flows. This would not occur in a contestable environment or if no regulation was imposed and the business would not necessarily seek to recover its tax liabilities at the time they were incurred, especially where the assets are eligible for accelerated depreciation. Accelerated depreciation has the effect of deferring tax on income earned in early years. Hence, looking forward under a post-tax regulatory framework there is a relative improvement in cash flows over time. So that this bonus does not appear as a windfall capital gain, the ICB based valuation should be adjusted downwards. The Commission uses the accumulated deferred tax liability normally calculated in statutory accounts to approximate this valuation bonus. The logic of this approach can be appreciated when it is recognised that the deferred tax amount is like an interest free loan from the Australian Taxation Office (ATO) or a free source of capital. Such free capital should not earn a rate of return and should therefore be removed from the asset base.

Under normal circumstances the loan is repaid when taxes are actually paid on future income. Under the regulatory framework the business does not feel the impact of tax liabilities on its cashflows because tax liabilities are specifically provided for in revenues at the point in time they are due. In the case of NT Gas it could be argued that there is no deferred tax liability since it leases its assets and there is no accelerated depreciation tax concession. While this is correct, it would be inappropriate to treat this regulated business different from others simply because it has what might be considered a different financing arrangement.

To make an appropriate deferred tax liability adjustment it is necessary to calculate a set of statutory accounts for the company as if it owned the assets in question and apply the accelerated tax provisions that would have been available to the company. When this is done the accumulated deferred tax liability remaining at 1 July 1999 is estimated to be $12.9m. Adjusting for the amount of the remaining deferred tax liability provides an initial capital base of $185.8m at 1 July 1999.

2.2.8 Conclusion

In assessing the initial capital base, the Commission has had regard to NT Gas' DORC calculations using both the straight-line methodology and Agility's proposed NPV-based approach to depreciating ORC. In addition, the Commission has been guided by the results of the Connell Wagner desk-top audit and has considered alternative valuations such as DAC, book value and residual value in determining an appropriate initial capital base for the ABDP.

The comparison of initial capital base valuations has been conducted as at 1 July 1999. The range of values is summarised in Table 2.5.

Table 2.5: Initial capital base valuations (as at 1 July 1999)

	NT Gas	Agility	Connell Wagner	ACCC
Initial Capital Base ($m)	$265[(a)]	$331 - $341[(b)]	$191[(c)]	$199[(c)]

Note: (a) Assumes straight-line depreciation to zero in 2066.
(b) Agility's NPV-based method for determining DORC
(c) Assumes accelerated depreciation from 1986 to a residual value of $61.84m in 2011.

The Commission has taken into account the Code's requirements when assessing NT Gas' proposed capital base valuation in the light of the Connell Wagner report, submissions by interested parties, the Commission's own analysis, its previous practice, the *Draft Regulatory Principles*, and NT Gas' own preference for a DORC approach. The Commission considers that its own calculation of the ICB is more robust than that of NT Gas. The Commission's assessment of the factors that section 8.10 of the Code requires the regulator to take into account is given in section 2.10.4.

In conducting its analysis the Commission has compared the proposed initial capital base values as at 1 July 1999, as was submitted in NT Gas' access arrangement. However, given that the access arrangement period will be five years from the date of final approval, the Commission has determined revenues for the five-year period commencing 1 July 2001. The Commission chose not to compare the proposed asset values as at 1 July 2001 due to the difficulty associated with accurately recalculating NT Gas' alternative asset valuations.[56] Taking the ICB valuation at 1 July 1999 adjusted for deferred tax liability, as well as inflation,[57] capital expenditure and depreciation since then, the Commission has calculated an initial capital base of **$176.2m** for the ABDP at 1 July 2001.

Proposed Amendment A2.1

In order for NT Gas' access arrangement for ABDP to be approved, the value of the initial capital base must be adjusted to the value derived by the Commission, **$176.2m** as at 1 July 2001.

56 While to some extent, the Commission was able to replicate NT Gas' asset valuations, the incomplete information regarding the exact methodology and values used by NT Gas to determine its alternative asset values, limited the accuracy of any revised valuations.

57 The actual inflation rate of 3.2 per cent was used for the year ending 30 June 2000 and a forecast inflation rate of 1.96 per cent was used thereafter.

2.3 New facilities investment and capital redundancy

2.3.1 Code requirements

The Code (section 8.9) states that the capital base at the commencement of each access arrangement period subsequent to the first is determined as:

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

(b) the New Facilities Investment or Recoverable Portion in the immediately preceding Access Arrangement Period; less

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

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

This leads to the issues of how capital expenditure and capital redundancies are to be treated under an access arrangement for the present period. These issues are the subject of this section.

New facilities investment

The Code (sections 8.15 and 8.16) allows for the capital base to be increased to recognise additional capital costs incurred in constructing new facilities for the purpose of providing services. The amount of the increase is the actual capital cost, provided the investment 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.

Unless the incremental revenue is expected to exceed the cost of the investment, the service provider (and/or users) must satisfy the regulator that the new facility has system wide benefits justifying higher tariffs for all users. Alternatively, the service provider must show that the new facility is necessary to maintain the safety, integrity or contracted capacity of services.

Under sections 8.18 and 8.19 of the Code a service provider may also undertake new facilities investment if the foregoing criteria are not met. To the extent that an investment does not meet the section 8.16 criteria or is speculative in character the augmentation of the capital base needs to be correspondingly reduced.[58]

Reference tariffs may be determined on the basis of forecast investment during the access arrangement period provided that such investment is reasonably expected to pass the requirements noted above when the investment occurs (section 8.20). However, the inclusion of forecast investment does not imply that the section 8.16 criteria have been satisfied. The regulator may reserve its judgment until the investment is undertaken or until the next review. The Code (section 8.22) also provides that the reference tariff policy should specify how discrepancies between forecast and actual investment are to be reflected in the capital base at the commencement of the next regulatory period (so as to meet the objectives of section 8.1 of the Code). Alternatively, the regulator may

[58] That part 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 necessary criteria.

determine how the expenditure will be treated for the purpose of section 8.9 (changes to the capital base) at the time the regulator considers revisions to an access arrangement.

Capital redundancy

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 is to occur at the commencement of the next access arrangement period so as 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 such a mechanism, the regulator must consider the potential uncertainty such a mechanism would cause and the effect that uncertainty would have on the service provider, users and prospective users.

Where redundant assets subsequently contribute to or enhance the provision of services, the Code (section 8.28) allows the assets to be added back to the capital base as if they were new facilities investment subject to the associated criteria noted earlier in this section.

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 (section 8.29 of the Code).

2.3.2 NT Gas' proposal

New Facilities Investment

As permitted by section 8.18 of the Code, section 4.4 of NT Gas' reference tariff policy states that 'NT Gas may undertake New Facilities Investment that does not satisfy the requirements of the Code for inclusion in the Capital Base'.[59]

In addition, the policy states that the speculative investment fund (the balance after deducting the recoverable portion of the new facilities investment), may subsequently be added to the capital base. This can occur if the type and volume of services provided, which use the increase in capacity attributable to the new facility, change such that any part of the speculative investment fund would then satisfy the requirements of the Code for inclusion in the Capital Base.[60]

In accordance with section 8.22 of the Code, the reference tariff policy stated that:

> … for the purposes of calculating the capital base at the commencement of the subsequent Access Arrangement Period, where the actual cost of New Facilities differs from the forecast New Facilities

59 Access Arrangement, p. 15.

60 Access Arrangement, p. 15.

> Investment on which the Capital Base was determined, the New Facilities Investment will be included at actual cost.[61]

NT Gas has disaggregated its new facilities investment into three components for this access arrangement period:

- capacity expansion – capital required to expand the capacity of the ABDP to meet demands both within the Access Arrangement Period and beyond;
- system replacement – capital required to maintain the integrity of the ABDP which would include items such as replacement of instrumentation (eg metering, telemetry remote terminal units etc), pipeline hardware (eg pipes, meters valves, regulators and fittings etc), site capital improvements (eg fencing, security etc), and specialised major spares; and
- non-pipeline system expenditure – capital required for replacement of items such as vehicles and computer equipment.[62]

NT Gas proposed the following capital expenditure program over the next five years (Table 2.6). NT Gas stated that the proposed expenditure represents best estimates and is required to maintain either the safety and integrity of the ABDP or its services to the satisfaction of Code requirements.[63]

Table 2.6: Estimated Capital Expenditure ($m)

Year Ending 30 June ($m)	2000	2001	2002	2003	2004
Expansion Capital	0	0	0	0	2.26
Replacement Capital	0.67	0.22	0.32	0.25	0
Non-System Capital	0.74	0.67	0.70	0.55	0.56
Total Capital Expenditure	1.41	0.89	1.02	0.80	2.82

Source: Access Arrangement Information, p. 21.

NT Gas stated that the $2.26m estimated expansion capital in 2004 is intended to increase the capacity of the Mereenie supply line.[64]

Capital redundancy

The reference tariff policy makes no comment on the treatment of redundant assets. NT Gas stated that there is currently no redundant capital in the ABDP.[65]

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61 Access Arrangement, p. 15.

62 Access Arrangement Information, p. 21.

63 Access Arrangement Information, p. 21.

64 Access Arrangement Information, p. 21.

65 Letter from Agility to the Commission, 7 December 2000.

2.3.3 Submissions by interested parties

No comments were received on this issue.

2.3.4 Commission's considerations

NT Gas' access arrangement does not comment on determining the asset base in subsequent access arrangement periods. While this is dealt with in section 8.9 of the Code, the Commission considers that there is some merit in the service provider acknowledging in an access arrangement the relevant sections of the Code and the intention of the service provider to implement the Code at the appropriate time. In relation to the ABDP access arrangement, the Commission considers that users and prospective users would benefit from clarification of how the capital base for the subsequent access arrangement period will be determined.

New facilities investment

The provisions in the access arrangement for adding new investments to the capital base follow the Code closely. However, an amendment to section 4.4 of the access arrangement is proposed by the Commission to aid in the interpretation of the access arrangement. The Commission considers that section 4.4 should be amended to state that new facilities investment may be undertaken by NT Gas irrespective of whether it satisfies section 8.16 of the Code, however, only that portion of investment which meets the requirements of section 8.16 may be included in the capital base.

Forecast capital expenditure

As permitted by section 8.20 of the Code, NT Gas has determined tariffs on the basis of forecast capital expenditure. However, section 8.20 states that this can only occur where the forecast expenditure is reasonably expected to pass the requirements in section 8.16. Based on the information available, it appears that the capital expenditure forecast by NT Gas would meet the criteria in section 8.16 of the Code. However, pursuant to section 8.21 of the Code, this does not imply that the Commission considers that the section 8.16 criteria are met. An assessment of the actual capital costs incurred will be made by the Commission at the time of the review of the access arrangement.

As discussed earlier, the Commission proposes to calculate revenues for the five-year period commencing 1 July 2001. The forecast capital expenditure for the years ending 30 June 2005 and 2006 are shown in Table 2.7. The Commission has completed its analysis and determined the revenue requirement on the basis of this forecast expenditure. The Commission acknowledges that total capital expenditure for 2005 and 2006 is lower than previous years and may only represent an approximation of capital expenditure. NT Gas will therefore be given the opportunity to provide the Commission with a revised estimate of capital expenditure for assessment.

Table 2.7: Estimated Capital Expenditure ($m) for 2005 and 2006

Year Ending 30 June ($m)	2005	2006
Expansion Capital	0	0
Replacement Capital	0.1	0.1
Non-System Capital	0.57	0.59
Total Capital Expenditure	0.67	0.69

Source: NT Gas' financial model for the ABDP.[66]

In addition, given that the capital expenditure for 2000 and 2001 is an input to the initial capital base at 1 July 2001, the Commission seeks verification from NT as to actual capital expenditure in 2000 and 2001, prior to the release of the Final Decision.

Adjustment to capital base for actual capital expenditure

Section 8.22 of the Code requires either the regulator to determine or the reference tariff policy to describe whether (and how) the capital base at the commencement of the next access arrangement period should be adjusted if actual capital expenditure differs from forecast capital expenditure. In this instance, NT Gas has included a statement in the reference tariff policy that new facilities investment will be included at actual cost (section 4.6). While this statement satisfies the requirement of section 8.22 of the Code, the Commission considers that it is inconsistent with section 8.16 of the Code.

At the commencement of the next access arrangement review, any new investment during the regulatory period has to be assessed by the Commission against section 8.16 of the Code, before it can be included in the capital base. However, section 4.6 of NT Gas' reference tariff policy currently appears to imply that *all* new facilities investment will automatically be included at actual cost regardless of whether it satisfies section 8.16 of the Code. The Commission therefore proposes the access arrangement be amended to remove any inconsistencies with section 8.16 of the Code.

Proposed Amendment A2.2

In order for NT Gas' access arrangement for the ABDP to be approved, clause 4 of section 4 of the access arrangement (the reference tariff policy) must state that new facilities investment that does not satisfy the requirements of section 8.16 of the Code may be undertaken by NT Gas. However, only that portion of the investment that satisfies section 8.16 of the Code may be included in the capital base.

In order for NT Gas' access arrangement for the ABDP to be approved, clause 6 of section 4 of the access arrangement must be amended to clearly specify that any new facilities investment must meet the requirements of section 8.16 of the Code before it can be included in the capital base.

66 Provided to the Commission on a confidential basis.

Capital redundancy

NT Gas has not included in its reference tariff policy a mechanism that will remove redundant capital from the capital base at the start of the subsequent access arrangement period, as provided for by section 8.27 of the Code. The Commission considers that such a mechanism is needed in order to ensure that users do not pay for assets that have ceased, or have substantially ceased, to contribute to the delivery of services. In this instance, the risks cited by NT Gas' regarding the potential redundancy of the ABDP further support the inclusion of a mechanism for the removal of redundant assets from the asset base. Accordingly, the Commission, pursuant to section 8.27 of the Code, requires that a mechanism dealing with redundant capital be included in the ABDP reference tariff policy.

Section 8.27 of the Code also states that the regulator must take into account any uncertainty caused by the inclusion of a redundant capital policy and the possible effects that uncertainty would have on the service provider, users and prospective users. It further states that if such a mechanism is included, the rate of return and the economic life of the assets should take account of the resulting risk (and cost) to the service provider of a fall in the revenue received from the sales of its services.

The Commission does not consider that placing a redundant capital policy in NT Gas' access arrangement materially increases uncertainty for the service provider or users. The current risk of stranding cited by NT Gas is the very reason that such a mechanism should be included in the access arrangement. The risk of stranding has already been clearly identified and providing for the removal of any redundant assets is unlikely to increase uncertainty for the service provider or users.

Further, the Commission also considers that the possible risks to revenues due to the inclusion of the redundant capital policy are minimal. Given that the ABDP is fully contracted until 2011, barring a force majure event, revenues are virtually guaranteed under the contract. Therefore, the revenue risk faced by NT Gas due to the inclusion of a redundant capital policy is negligible. In addition, the provision for accelerated depreciation of the pipeline assets allows for a substantial return of capital by 2011 sufficiently compensating NT Gas for the risks associated with the stranding of the pipeline assets.

Proposed Amendment A2.3

In order for NT Gas' access arrangement for the ABDP to be approved, the reference tariff policy must be amended to allow the Commission, at the commencement of the subsequent access arrangement period, to review, and if necessary adjust, the asset base for wholly or partially redundant assets, within the meaning of section 8.27 of the Code.

2.4 Depreciation and inflation

2.4.1 Code requirements

Sections 8.32 and 8.33 of the Code set out the principles for calculating depreciation for the purposes of determining a reference tariff. In brief, the depreciation schedule should meet the following principles:

- It should result in the reference tariff changing over time consistently with the efficient growth of the market for the services provided.
- Depreciation should occur over the economic life of each asset or group of assets, with progressive adjustments to the maximum extent that is reasonable to reflect changes in expected economic lives.
- Subject to the capital redundancy provisions (section 8.27), an asset is to be depreciated only once. Thus the total accumulated depreciation of an asset will not exceed the value of the asset at the time the asset or group of assets was first incorporated in the capital base.

Section 8.5 permits any methodology to be used to determine the total revenue requirement, provided it can be expressed in terms of one of the methodologies described in section 8.4 of the Code.

2.4.2 NT Gas' proposal

Depreciation

NT Gas proposed the use of a 'kinked straight line' depreciation methodology for the accelerated depreciation of its transmission pipeline assets and a standard straight line methodology for its remaining assets (ie compressor stations, regulation, metering and odourisation stations, SCADA and communications and non system assets). Depreciation has been applied over the economic lives of the relevant assets in both cases.

NT Gas considered the use of straight line depreciation to be in accordance with the Code, and intends to revisit and where necessary adjust the depreciation schedule to reflect changes in expected asset economic lives.[67]

As shown in Figure 2.2, NT Gas proposed to depreciate the transmission pipeline assets from its DORC valuation of $251.51m at 1 July 1999 to $61.84m in 1 July 2011 using accelerated depreciation. It is further proposed that from 1 July 2011 until the end of the asset's useful life (2066) it will be depreciated on a straight line basis. NT Gas chose 2011 as the timing of the kink to coincide with the expiry of the existing transportation contract. NT Gas believed 'that it is appropriate that the depreciation schedule should mirror the existing contractual and financial arrangements for the pipeline.'[68]

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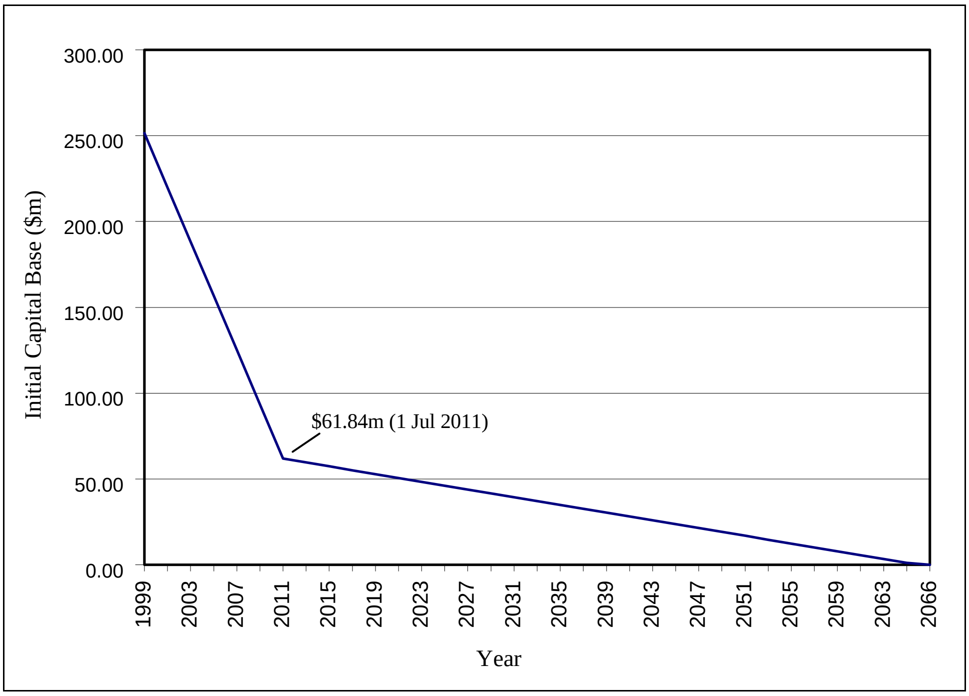
[67] Access Arrangement Information, p. 17.

[68] Access Arrangement Information, p. 19.

NT Gas proposed the kinked depreciation profile 'to reflect its concern about the sustainability of current levels of throughput over the economic life of the pipeline (that is out to 2066).'[69] NT Gas contended that there is significant uncertainty as to the remaining economic life of the pipeline given the expiration of its foundation gas transportation contract in 2011, the lack of information on future production expectations of the Amadeus Basin, and the potential for the Timor Sea to become the prominent source of gas in the Northern Territory at some future time.[70]

Figure 2.2: NT Gas' proposed pipeline depreciation schedule (commencing 1 July 1999)



NT Gas submitted that given the growth prospects of the Australian domestic gas market and the depressed demand for LNG in Asia, it is likely that any near term development of the Timor Sea gas fields would focus on delivering gas to the Australian domestic market. Should the Timor Sea project proceed, gas would be brought on-shore to Darwin effectively by-passing the ABDP. Furthermore, should Timor Sea gas be delivered to other parts of Australia, NT Gas believes it unlikely that the gas would be delivered via the ABDP, given the relatively small capacity of the pipeline.[71]

Working capital

In calculating its return on assets, NT Gas has included an allowance in the capital base for working capital, calculated as accounts payable less accounts receivable plus

69 Access Arrangement Information, p. 18.

70 Access Arrangement Information, p. 18.

71 Access Arrangement Information, p. 18.

taxation payable. NT Gas estimated the working capital required to fund the day to day operation of the ABDP to be $0.28m (negative) as at 30 June 1999.[72]

2.4.3 Submissions by interested parties

The Commission received substantial comment on NT Gas' proposed depreciation methodology.

Santos questioned the justification for NT Gas' proposal to accelerate depreciation of the transmission pipeline:

> This depreciation profile equates to $15.6 million per year of depreciation, which adds approximately $1/GJ to the total Reference Tariff. This approach is at odds with the modest $48 million total depreciation applied since the pipeline commenced operation in 1987 (ie $4 million per year).[73]

Santos suggested that should the access arrangement be considered in the context of future use by off-shore gas suppliers (for back haul services), then this would significantly extend the useful life of the ABDP in which case the proposed depreciation schedule would be inappropriate.[74]

NTPG claimed that the proposed depreciation schedule 'ignores the fact that under any credible scenario of gas demands, significant reserves of economically recoverable gas will remain to be shipped after 2011'[75] and considers 26 years a reasonable remaining economic life to use for depreciation purposes.

NTPG estimated that approximately 640 PJ of proven plus probable gas reserves remain, which could be shipped on the ABDP. Based on used and remaining reserves, NTPG then calculated depreciation to be $0.65/GJ (July 2000 dollars) or a total of $10.2m in 2000 reducing the reference tariff in 2000 from $3.63/GJ to $3.16/GJ. NTPG stated:

> …the depreciation methodology used to determine tariff charges for the Reference Service is counter to the public interest. It appears designed to raise the barrier to entry for prospective competitors in the Katherine-Darwin regional electricity market. It is an approach which results in price discrimination favouring the foundation customer, and counter to the interests of prospective users of the Reference Service.[76]

NTPG also considered that the potential for Timor Sea gas to supply the Darwin market is not new as Timor Sea gas discoveries were known prior to the approval and commissioning of the pipeline.

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72 Access Arrangement Information, p. 19.

73 Santos submission, 17 September 1999, p. 5.

74 Santos submission, 17 September 1999, p. 4.

75 NTPG submission, 12 September 1999, p. 8.

76 NTPG submission, 12 September 1999, p. 10.

Finally, NTPG contended:

> By depreciating transmission pipeline assets from a DORC valuation of $251.52 million in July 1999 to $61.84 million in 2011, the approach seeks to recover from potential users of the proposed Reference Service, any under-recovery of capital to date.[77]

Woodside submitted that the proposed accelerated depreciation schedule is inappropriate given that the pipeline is only ten years old. According to Woodside, 'depreciation should be a straight line over the lesser of the commercial lifetime or technical lifetime of each asset type that makes up the pipeline system.'[78]

2.4.4 Commission's considerations

Depreciation

As discussed earlier in section 2.2.7, the Commission is concerned that NT Gas' proposed initial capital base and accelerated depreciation schedule are inconsistent. This inconsistency arises because accumulated depreciation for valuation purposes has been calculated on a straight line basis assuming an economic life of 80 years, whilst the proposed accelerated depreciation profile suggests a significant decrease in the utilisation of the pipeline after 2011. It would appear from this that NT Gas is seeking to simultaneously maximise the return on assets and return of assets..

In the *Draft Regulatory Principles* (DRP),[79] the Commission proposed that service providers identify, at the start of each regulatory review, those assets that are subject to by-pass risk and to nominate a more appropriate asset valuation. The Commission's preferred approach, as outlined in the *Draft Regulatory Principles,* is for the service provider to anticipate potential asset redundancy. The Commission would then appropriately provide for the redundancy of the identified assets via an increased depreciation allowance.

As discussed in section 2.2.7, the Commission considered that a number of the risks cited by NT Gas were valid when determining an appropriate ICB for the ABDP. Given the Commission's approach, the arguments for accelerated depreciation of the ABDP's pipeline assets are even stronger. This is especially the case in the context of recent developments in respect of Timor Sea gas reserves.

Timor Sea gas

In its submission, PAWA signalled its interest in purchasing Timor Sea gas, depending upon the terms and conditions of supply and when the gas becomes available. However, PAWA cautioned that for each of the three potential offshore sources,[80]

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77 NTPG Submission, 12 September 1999, p. 9.

78 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p. 4.

79 ACCC, *Draft Statement of Principles for the regulation of Transmission Revenues*, 27 May 1999, p. 25.

80 Petrel and Tern field, Bayu-Undan field & Greater Sunrise/Evans Shoal fields.

PAWA's demand alone would not be sufficient to economically justify bringing gas onshore to Darwin. At least one other customer of PAWA's size would be required.[81]

In November 2000 Woodside and Phillips Petroleum announced that they had reached an in-principle agreement to pursue cooperative development of their Timor Sea gas resources for the supply of gas to Darwin.[82] According to Woodside, it is expected that supply from the Bayu-Undan field will commence in 2004 and production from the Greater Sunrise field is targeted for 2005-7. Woodside stated that the combined reserves of both fields have the ability to meet the long term requirements of a large customer base including Nabalco, PAWA and domestic gas markets in South East Australia.[83]

More recently, it was reported that the $10 billion development of the Timor Sea gas reserves was almost certain to go ahead with Phillips announcing that it had signed a letter of intent for a 25-year supply of LNG from its plant, to be constructed in Darwin.[84]

Epic Energy has also announced its intention to construct a $1-$1.5 billion high pressure pipeline to transport Timor sea gas from Darwin to Moomba for distribution to South East Australia.[85] If the project proceeds, Epic anticipates delivery of gas to occur in the first quarter of 2004 with an initial pipeline capacity of 100PJ per annum, increasing to a fully compressed capacity of 200PJ per annum.[86]

Given the limited capacity of the ABDP, it appears that Epic Energy currently has no intention of utilising the ABDP and should the project go ahead it is more than likely to result in a major by-pass of the pipeline. With the majority of the ABDP's market located in Darwin, it is likely that gas transportation along the ABDP would be limited to supplying a small number of users located along the lower portion of the pipeline. It should be noted however, that while planning for Epic Energy's proposal has advanced significantly, the construction of the pipeline is by no means a forgone conclusion.

The Commission cannot rule out the possibility that alternative project proposals involving Timor Sea gas exist. While some of these projects might involve the ABDP, others may by-pass the pipeline entirely. Therefore, the ultimate involvement of the ABDP in the delivery of Timor Sea gas to South East Australia remains uncertain. However, it is evident that the majority of options for the delivery of Timor Gas to Southern markets are likely to result in the significantly reduced utilisation and/or the partial stranding of the ABDP.

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81 NT and PAWA submission, 17 November 1999, p. 6.

82 Woodside Media Release, *Woodside and Phillips agree to Timor sea cooperation*, 30 November 2000.

83 Woodside Petroleum, *Investor Presentation*, December 2000.

84 The West Australian, *WA to Ride $10B Timor Gas Play*, 10 March 2001, p. 54.

85 Epic Energy Media Release, *MPF Status for Epic's Timor Sea Project*, 8 November 2000.

86 Gas Regs, *2,200km 300TJ/d East Timor Bayu-Undan pipeline from Darwin to Moomba in SA*, Monday, 12 February, 2001. Vol 1, No 14, p. 5.

Expiration of foundation contract

The NT Government and PAWA have confirmed that the contract between PAWA and NT Gas for gas transportation expires in 2011. Whether PAWA chooses to renew its contract with NT Gas will depend on the commercial terms being offered for the supply of gas by the Amadeus Basin and offshore gas producers at that time.[87]

Future production expectations of Amadeus Basin

The NT Government and PAWA contend that if the Mereenie field were to supply the balance of PAWA's requirements for gas, the field's remaining proven reserves would be exhausted by about 2015.[88]

A report to the Timor Sea Consultative Group in May 1999 stated:

> PAWA suggests that contracted gas from the Amadeus Basin may not meet demand and anticipates that little gas will be available under existing contracts by 2010 … I understand that the Amadeus Basin producers and PAWA are negotiating for additional gas supplies to alleviate shortfalls in gas supply over the period to 2005. However, supplies thereafter remain problematic.[89]

More recently, both Phillips and Woodside/Shell have been negotiating to pick up a 30 PJ per annum contract with PAWA, which would gradually replace supplies from the Amadeus Basin by 2012.[90]

Confidential projections provided to the Commission by the NT Government and PAWA and others also lent support to the uncertainty regarding future production expectations of the Amadeus Basin.

Use of ABDP for back haul services

The NT Government and PAWA consider that the supply of offshore gas to southern markets through the ABDP is unlikely, given that the size of those markets would require a pipeline of much greater capacity or substantial augmentation of the pipeline. Rather, only a relatively small amount of gas would travel through the pipeline from the Amadeus Basin to supply regional areas such as the McArthur River Mine and Tennant Creek. [91]

While it currently uses imported fuel oil, Nabalco has investigated the viability of using gas as the main energy source for its mine and alumina refinery at Gove (equivalent to 25PJ per annum, with the potential for consumption increasing up to 40PJ). Nabalco envisages that there is little likelihood that gas could be delivered to Gove from the Amadeus Basin, however, it is possible that Timor Sea gas could be economically

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[87] NT and PAWA submission, 17 November 1999, pp. 2 – 3.

[88] NT and PAWA submission, 17 November 1999, p. 3.

[89] M J Kimber Consultants, *Opportunities for Timor Sea Gas in the Northern Territory and Queensland*, A Report to Timor Sea Consultative Group Convened by Northern Territory Office of Resource Development, 27 May 1999, p. 12.

[90] The Australian, *Huge Timor Gas Deal Looms as Darwin Plant Deal Firms*, 23 January 2001, p. 26.

[91] NT and PAWA submission, 17 November 1999, p. 7.

delivered by upgrading and reversing the direction of pipeline flow and constructing a 600km spur line to Gove.[92]

As discussed in section 3.2.6 of this Draft Decision, the development of offshore gas reserves and submissions by interested parties indicate that there is evidence to suggest a back haul service could be sought on the ABDP.

Assessment of the risk of stranding

Given the discussion above, the Commission considers it likely that Timor gas will be onshore before 2011. Evidence suggests that an alternative source of gas will become necessary in the future, and Timor Sea gas reserves may well be in the best position to meet the demands of current and prospective users. If Timor Sea were to replace the Amadeus Basin as the major supplier of gas to Darwin, a significant portion of the ABDP's current market could potentially be eliminated, severely diminishing pipeline usage.

The Commission notes the submissions by Woodside/Shell and Nabalco, stating that a back haul tariff on the ABDP would be appropriate. While there is an expectation that a back haul service could be requested on the ABDP, there are no formal requests or proposals for a back haul service currently in existence and the Commission cannot be certain that such usage would eventuate. Furthermore, the Commission is not in a position to estimate the ABDP's level of involvement in potential projects to transport Timor Sea gas to southern markets.

It is the Commission's view that the risk of stranding faced by the ABDP due to the expiration of its foundation contract in 2011 and the uncertainty surrounding the remaining Amadeus Basin gas reserves appear valid. On their own, these circumstances suggest a risk of at least partial stranding. When combined with the potential for Timor Sea gas to replace Amadeus Basin gas as the supply source for the Darwin market, the result is a substantial risk that utilisation of the pipeline would be significantly reduced.

Based on the information provided, the Commission is satisfied that there is sufficient evidence to support NT Gas' assertion that the ABDP is likely to face a significant risk of stranding after 2011.

Residual value of the pipeline in 2011

As stated earlier, the Commission is satisfied that $61.84m is an appropriate valuation for the ABDP's pipeline assets in 2011. In light of further developments, it may become necessary to reassess the residual value, and hence depreciation, of the pipeline in subsequent access arrangements.

Conclusion

It should be noted that the redundancy of assets can also reflect an error in judgement on the part of the investor and it may not be appropriate to compensate a service provider for a poor investment decision through accelerated depreciation. While the

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[92] Nabalco submission, 9 September 1999, pp. 1-2.

Commission has accepted NT Gas' proposal for accelerated depreciation in this instance, it will continue to assess other proposals for accelerated depreciation on a case by case basis.

The Commission believes that its approach to accelerated depreciation appropriately reflects the projected usage of the pipeline and the risks of partial stranding after 2011. Future developments in the gas market may, however, affect the risk of stranding faced by NT Gas. The Commission will monitor these developments and reassess the risk of stranding and the residual value of the pipeline (currently estimated at $61.84m) in subsequent revisions.[93] NT Gas also has the ability to submit revisions to the access arrangement under section 2.28 of the Code at any time during the access arrangement period.

Proposed Amendment A2.4

In order for NT Gas' access arrangement for the ABDP to be approved, the depreciation schedule must be based on straight line accelerated depreciation of the Commission's initial capital base of $176.2m at 1 July 2001 (discussed in section 2.2.8) to a residual value of $61.84m at 1 July 2011.

Working capital

The Commission notes NT Gas' proposal to include an allowance (negative $0.28m in the first year) in the capital base for the purposes of calculating the return on capital. A US authority quoted by EAPL defined working capital as follows:

> … the average amount of capital provided by investors … over and above the investment in plant … required to bridge the gap between the time that expenditures are required to provide service and the time collections are received for that service.[94]

The Commission has not explicitly modelled the timing of NT Gas' cash flows throughout the year. Rather, the Commission's cash-flow analysis assumes that all costs and revenues are incurred on the last day of the financial year (ie, 30 June). In reality, NT Gas' cash flows would occur at regular intervals throughout the year, giving the company a benefit over and above the regulated revenue. That benefit is equal to the time value of money on all net cash flows prior to 30 June each year. The Commission considers that this benefit more than compensates NT Gas for any 'gap' between payments and collections that may occur throughout the year.

Consequently, the Commission proposes not to include the initial allowance for working capital, and changes in the level of working capital thereafter, in the capital base for the purpose of calculating NT Gas' return on capital.

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[93] Any reduction or increase in the estimated residual value in 2011 would be addressed through an adjustment to the depreciation schedule.

[94] Ohio PUC, Re *Columbus Southern Power Co*, 1992 133 PUR4th 525, 550, quoted by EAPL in *Access Arrangement Information*, 5 May 1999, p. 28.

Proposed Amendment A2.5

In order for NT Gas' access arrangement for the ABDP to be approved, for the purpose of calculating NT Gas' return on capital assets, the working capital component must not be included in the capital base.

2.5 Rate of return

2.5.1 Code requirements

As noted earlier, the Code (sections 8.30 and 8.31) states that the rate of return should provide a return that is commensurate with prevailing conditions in the market for funds and with the commercial risk associated with providing the reference service. The Code suggests as an example using a weighted average of the returns applicable to each type of capital (equity, debt and any other source of funds), commonly known as the 'weighted average return on (cost of) capital' or 'WACC'. Such returns would be determined on the basis of a well accepted financial model such as the capital asset pricing model (CAPM). The financing structure assumed should also reflect standard industry structures and best practice. However, a service provider may adopt other approaches if the regulator is satisfied that the objectives regarding the design of the reference tariff and reference tariff policy set out in section 8.1 of the Code are met.

2.5.2 NT Gas' proposal

NT Gas relied heavily on the Commission's *Final Decision* for the access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others (Victoria *Final Decision*)[95] in calculating the weighted average cost of capital (WACC), but argued for a higher WACC on the basis that the ABDP is a comparatively riskier venture.

NT Gas pointed out the following differences between the ABDP and the Victoria infrastructure:[96]

- The Victoria decision was substantially completed prior to the full impact of the accident at the Longford gas processing plant was known, and therefore, the risks associated with pipeline investment are unlikely to have been fully incorporated into the Commission's decision on risk;

- There is a greater risk of field failure as the Amadeus Basin is much smaller than Bass Strait and there is less associated oil and on site and off site support and analysis available to the Amadeus Basin field;

- The location and commercial environment is more risky than in Victoria. Much of the ABDP is located in remote and relatively inaccessible regions. Demand for gas

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95 ACCC, Access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others, *Final Decision*, 6 October 1998.

96 Access Arrangement Information, pp. 22-25.

is dependent on the condition of the resource market, the armed forces and South East Asian economies. In addition, NT Gas does not hold easements for the pipeline but relies on the NT government providing right of way;

- The inability of insurance to adequately cover all natural and force majeure style risks. ABDP is subject to greater risks than other Australian pipelines ie flooding, wash outs and earthquakes. These disasters affect gas usage levels of ABDP customers which cannot be fully recovered from 'natural risk' style expenses through insurance;

- Explicit regulation has never been applied to the ABDP. It is uncertain how industry participants and customers will react to regulation;

- The much lower levels of maturity of the ABDP's markets. Markets are slowly developing but there is only a limited range of applications suitable for gas;

- The much higher levels of concentration of usage among ABDP's consumers. PAWA has contracted 99 per cent of pipeline throughput to generate electricity and as a consequence ABDP is vulnerable to any shift in fuel usage or gas source;

- The risky nature of many of the ABDP's smaller consumers. Mining sites are usually served by dedicated lateral pipelines which are uneconomic if the mine folds. Given the exposure to commodity markets this risk of failure is significant; and

- The high city gate price for gas in the NT restricts market growth and the competitiveness of natural gas with other fuels.

In view of these risks specific to the ABDP, NT Gas proposed a pre-tax real WACC of 11 per cent.

The underlying parameters, equations and other assumptions used within the CAPM framework to develop the proposed post-tax nominal WACC and other WACC derivatives are summarised below in Table 2.8.

Table 2.8: Parameter ranges proposed by NT Gas for WACC calculations

Parameter		Ranges	
		High	Low
General Economic Parameters	Inflation Corporate Tax Rate Imputation Take Up Rate	2% 36% 25%	3% 36% 50%
Gearing	Debt Equity	50 50	60 40
Cost of Debt	10 Year Bond Rate 2010 CPI Linked Bond Rate Debt Margin Bank Costs	5.9% 3.7% 1.4% 0.5%	5.5% 3.4% 1.0% 0.5%
Nominal Cost of Debt	Based on 10 Year bond rate Based on CPI Linked Bonds	7.3% 7.6%	6.5% 6.9%
Cost of Equity	Market Risk Premium Asset Beta Equity Beta Margin for Asymmetric Risk Margin for Self Insured Risk	7.0% 0.9 1.65 1.0% 0.5%	6.0% 0.55 1.25 0 0
Nominal Cost of Equity	Based on 10 Year Bond Rate Based on CPI Linked Bonds	19.0% 19.3%	12.9% 13.3%
WACC Results	Nominal Post Tax WACC Nominal Pre Tax WACC Real Pre Tax WACC	10.9% 17.0% 14.1%	6.5% 10.2% 7.5%

NT Gas modified the usual CAPM calculation of the cost of equity by adding a measure for asymmetric risk and an allowance for self insurance. Consequently, NT Gas' nominal cost of equity (r_e) equation is:

$$r_e = r_f + \beta_e (r_m - r_f) + \text{asymmetric risk} + \text{self insurance}$$

The nominal cost of equity is a key variable in determining the rate of return. NT Gas defined the post-tax nominal WACC (W) by the formula:

$$W = r_e \frac{(1-T)}{(1-T(1-\gamma))} \frac{E}{D+E} + (r_f + D_m)(1-T)\frac{D}{D+E}$$

NT Gas' conversion from post-tax nominal to pre-tax real WACC was performed on the basis of firstly adjusting for tax and then for inflation.

Recognising that the upper and lower ends of all the ranges of the above parameters are unlikely to occur simultaneously, NT Gas identified the following as being reasonable ranges:

Parameter	Low	High
Cost of Equity	14.3%	17.3%
Cost of Debt	6.7%	7.4%
Real Pre Tax WACC	8.5%	11.7%

NT Gas chose a pre-tax real WACC of 11 per cent from the upper end of the range, arguing that a WACC from the lower end could be a disincentive for investment given the immature state of infrastructure development in the NT.[97]

2.5.3 Submissions by interested parties

Woodside submitted that the pre-tax real WACC of 11 per cent is too high and that this is the driver for the proposed 'unrealistic' tariffs. Woodside stated:

> …there would seem to be no strong qualitative reasons that suggest that the systematic risk of the Northern Territory assets would be any different to those in other parts of Australia or, for that matter, the world. That is, there is no basis for Northern Territory onshore gas transmission pipeline assets' WACC to be greater than the rates determined in Victoria.[98]

NTPG made a number of comments regarding NT Gas' WACC proposal, including that the financing of the ABDP by a prudent operator should be at the lowest available cost of capital. NTPG wrote:

> Nominal cost of equity capital appears twice as high as that of debt. In these circumstances a prudent operator would finance the project solely by debt. The question as to whether lenders would support a project such as ABDP without requiring a significant component of equity financing needs to be addressed.[99]

NTPG also commented on the proposed cost of debt. Given that ABDP revenues are underpinned by the NT Government's guaranteed shipping contract, NTPG is of the view that the long term Australian government bond rate would be the appropriate cost of debt.[100]

Both Santos and Nabalco submitted that the proposed real pre tax WACC is too high given the WACC determinations made in respect of other declared pipelines, and the current gas delivery arrangement.[101] Nabalco stated:

> In particular the risk factor appears overstated for what is essentially a fixed supply to a Government utility.[102]

2.5.4 Commission's considerations

Calculation of WACC

Given the critical nature and complexity of the WACC in determining revenue, hence profits, there is a substantial degree of sensitivity regarding the value of the WACC. Consistent with section 8.30 of the Code, the Commission's approach is to determine

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97 Access Arrangement Information, p. 29.

98 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p 2.

99 NTPG submission, 12 September 1999, p 4.

100 NTPG submission, 12 September 1999, p 5.

101 Nabalco submission, 9 September 1999, p 2 & Santos submission, 17 September 1999, p. 5.

102 Nabalco submission, 9 September 1999, p 2.

the WACC with due consideration of prevailing financial market benchmarks[103] and the level of commercial risk involved in maintaining the service infrastructure through which the reference service is delivered.

NT Gas converted the post-tax nominal WACC to a pre-tax real WACC by adjusting for tax and then for inflation. As noted in its Victoria *Final Decision*, the Commission considers that such conversions to the pre-tax real WACC give rise to errors.[104] In that instance, the Commission used cash-flow modelling to derive the pre-tax real WACC that yielded the post-tax nominal cost of equity indicated by the CAPM.

The Commission indicated in its Victoria *Final Decision* that a post-tax WACC framework is preferred to a pre-tax WACC framework. Commercial returns to investors, including those indicated by CAPM, are invariably expressed in post-tax nominal terms. If two investments involving similar risks provide the owner with the same return before tax but a different net return after tax, an investor will prefer the investment that gives the higher net after-tax return. Indeed, if the investments are available as shares listed on the stock exchange the price of the one with the higher return will be bid up relative to the other so that the post-tax returns to investors are equalised.

It follows that if, in regulating a service provider's revenues, the regulator takes account of the taxes likely to be paid by the service provider given its financial structure, the output from application of CAPM to the regulatory accounts will be the appropriate commercial return for the business.

If there are features of the taxation system that give benefits to shareholders in addition to dividend cash-flow, for completeness these need to be taken into account when assessing the prospective return to shareholders. The value of imputation credits to shareholders is one such benefit to be accounted for in the Australian context.

Following the release of the *Draft Regulatory Principles*,[105] the Commission has applied the post-tax methodology in all of its subsequent decisions including the Transgrid *Final Decision*,[106] Central West Pipeline (CWP) *Final Decision*,[107] MAPS *Draft Decision*,[108] and MSP *Draft Decision*.[109]

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[103] The Commission has used financial market data as at 24 April 2001 to determine the WACC in this Draft Decision. This will be updated for the most recent market data available at final decision stage.

[104] ACCC, Access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others, *Final Decision*, 6 October 1998, p. 61.

[105] ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999.

[106] ACCC, 'NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04', *Final Decision*, 25 January 2000.

[107] ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision*, 30 June 2000.

[108] ACCC, 'Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System', *Draft Decision*, 16 August 2000.

Section 8.30 of the Code states that the rate of return used in determining the reference tariff should provide a return that is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service. In the Commission's view, a post-tax WACC better achieves that objective than does a pre-tax WACC. Applying a pre-tax WACC without consideration of the service provider's financial needs in the light of its tax liabilities would risk under or over-providing for revenues over the life of the asset. Therefore, the Commission is of the view that the post-tax methodology is superior and has applied that methodology in determining NT Gas' revenues and tariffs in the Draft Decision.

WACC parameters

The development of a WACC figure from the cost of equity requires certain parameters and assumptions. The values assigned to the financial parameters remain contentious and warrant discussion in some detail since they form the basis for determining the permitted rate of return on the regulated assets. Accordingly, each parameter will be dealt with in turn in the remainder of this section.

The key parameters are:

1. the risk-free interest rate (r_f), the real risk-free rate (rr_f) and, by implication, the anticipated rate of inflation (f) and the interest rate applicable to debt (r_d);
2. the market risk premium (MRP);
3. the likely level of debt funding (D/V);
4. the likely utilisation of imputation credits (γ);
5. the effective tax rate (T_e); and
6. the equity beta (β_e) relevant to stand-alone operation within the proposed regulatory framework.

Interest rates and inflation

As discussed earlier, the Code (section 8.30) states that the rate of return should be 'commensurate with prevailing conditions in the market for funds.' This implies that all information for deriving the rate of return should be as up to date as possible at the point the access arrangement comes into effect. It also means that the rate of return should match the circumstances (economic conditions) of the regulatory framework. For example, the term of the interest rate should correspond to the term of the regulatory period. Interest rates and inflation expectations are parameters set by the financial markets on a daily basis and are readily determined.

Generally, the relevant WACC for regulatory purposes should be a forward-looking concept, giving an indication of the minimum average expected commercial return on debt and equity. Selected interest rates and inflation estimates relevant to the setting of the WACC have been derived from financial market data and are shown below in Table

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[109] ACCC, 'Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System' *Draft Decision*, 19 December 2000.

2.9. These figures will be recalculated using the most recent financial data at final decision stage.

NT Gas adopted a nominal ten-year bond rate and the CPI indexed bond 2010 series plus inflation component as indicators of the risk free rate. NT Gas recognised that these rates should be ‘on the day’ but has averaged the figures over an undefined ‘short period of time’ to remove volatility.[110]

Ten-year bond rates can be used as a proxy for the risk free rate. However, the Commission considers that the term associated with the risk free rate should coincide with the duration of the access arrangement period. Thus, five-year bond rates are used in reference to access arrangements with an expected initial access arrangement period of five years. In addition, the five-year bond rate has the advantage of a lower built-in premium to compensate for inflation risk. A ten-year bond rate is usually higher than the five year rate because, in part, it accommodates a risk premium for inflation uncertainty. As the regulatory framework already compensates the service provider for inflation risk through the use of a CPI-X adjustment mechanism, the inclusion of an inflation risk premium in the risk free rate used for determining the cost of capital is inappropriate. Accordingly, the Commission considers that five-year rates are appropriate for this analysis.

As discussed in section 0, the absence of a CPI adjustment mechanism in NT Gas’ tariff escalator means that NT Gas bears the risk that the inflation rate may be lower or higher than currently forecast, resulting in tariffs which may over or under compensate for actual costs. An amendment to the access arrangement is proposed by the Commission to implement a CPI-X mechanism to calculate future tariffs. This amendment removes the inflation risk currently borne by NT Gas in its proposed access arrangement.

Although, in theory, an on-the-day rate is considered the best indicator of the opportunity cost of capital at any point in time, the Commission accepts that there is some merit in averaging rates over a short period to abstract from day-to-day market volatility. The *Draft Regulatory Principles* proposes the use of a 40-day moving average of the relevant bond rates covering the period prior to the decision analysis. This methodology was used by the Commission in the CWP and Transgrid *Final Decisions* and the MAPS and MSP *Draft Decisions*. This approach has been adopted by the Commission for NT Gas, resulting in a nominal risk-free rate of **5.0 per cent** and a real risk-free rate of **2.98 per cent** as indicated in Table 2.9 below. These rates will be revised at final decision stage.

110 Access Arrangement Information, p. 27.

Table 2.9: Current financial market interest rates and inflation expectations

Financial Indicator	Proposed by NT Gas (per cent p.a.)	40-day moving average ending 24 April 2001 (per cent p.a.)[(a)]
5 year government bond rate		5.00
10 year government bond rate	5.5 - 5.9 [(b)]	5.30
CPI indexed bonds (2005 series)		3.07
CPI indexed bonds (2010 series)	3.4 - 3.7 [(b)]	3.19
Estimated 5 year real rate[(c)]		2.98
Implied 5 year inflation expectation[(d)]		1.96

Notes:

(a) Based on daily closing quotations as published by the Reserve Bank of Australia. The Commission finalised its calculations of WACC for this Draft Decision on 24 April 2001.
(b) NT Gas calculated this as the average over an undefined 'short period of time'.
(c) Interpolations based on indexed bond figures.
(d) Inferred from the difference between nominal and real interest rates over the corresponding period using the Fisher Equation, (1+ir) = (1+in)/(1+CPI), where:
ir = real interest rate, in = nominal interest rate and CPI = inflation rate.

While the inflation rate is not an explicit parameter in the WACC estimation, it is an inherent aspect of the nominal risk-free rate and cost of debt parameters. It is fundamental to deriving real rates of return, which are used in the target revenue and economic depreciation calculations. It is also an important determinant of the effective tax liability. NT Gas has suggested a range for the annual rate of inflation of two to three per cent over the initial five year price setting period but has used a rate of 2.5 per cent in all its analysis.

An indication of the rate of inflation anticipated by financial markets is provided by the difference between the nominal bond rates and rates for inflation-indexed bonds for the same term. The indexed bond series have maturity dates that do not correspond to current five or ten-year bond rates. However, the corresponding figures are readily derived by interpolation and are shown in Table 2.9 above. These figures represent the real risk-free rate corresponding to the current nominal risk-free rate (based on the five-year bond yield) and indicate that the current expectation of inflation (f) over the initial regulatory period is **1.96 per cent**.

The Commission will use this market-derived inflation rate in its calculations. Official forecasts of inflation are inevitably a little out of date, may be subject to institutional bias[111] and do not necessarily relate to the access arrangement period under consideration.

Accordingly, the Commission considers that NT Gas' revenue requirement for the access arrangement period should be recalculated using a forecast rate of inflation of

111 NERA, *A critique of the WACC parameters proposed for Transgrid – a report for the Commission,* March 1999, p. 9.

1.96 per cent and observed inflation rates where this is appropriate. The Commission will revise the forecast rate of inflation based on the most up-to-date information available at the date of final decision.

Debt margin and cost of debt

NT Gas has suggested that the appropriate margin for the cost of debt is around 100-140 basis points above the relevant risk-free rate and noted that the Commission had adopted 120 basis points in the Victoria *Final Decision*.[112]

The lending margin is essentially an empirical matter. In the Victoria *Draft Decision* the Commission proposed a debt margin of 80 basis points. However, in the period following the release of the *Draft Decision* there was evidence that margins might have increased because of the then growing uncertainties in global financial markets. On the basis of comments by financial institutions, the Commission adopted an assumed debt margin of 120 basis points in the *Final Decision*.

The Commission notes the recent decision by the Office of the Regulator General (ORG) to increase the debt margin from 1.20 to 1.50 for Victorian electricity distributors, in light of current information from capital markets.[113] The ORG accepted evidence provided in submissions and by market practitioners that a debt margin of 1.20 per cent might understate the benchmark borrowing costs for an efficiently financed electricity distributor.[114]

The Commission also notes IPART's final decision on the AGL Gas Network's (NSW) access arrangement in which it determined a range for the debt margin of 0.90-1.10. In arriving at this decision the Tribunal considered recent corporate debt issues as a guide for the current premium on long term debt. IPART found that margins over the 10-year bond rate for five corporate debt issues that took place between June 1999 and March 2000 ranged between 80 and 100 basis points.[115]

In view of this recent financial market data, the Commission considers it appropriate to continue using a debt margin of **120 basis points** for its calculations on the ABDP. The Commission will continue to monitor capital markets for further evidence that the debt margin could be other than 120 basis points.

The 120 basis point margin in combination with the nominal risk-free rate of 5.0 per cent suggests a nominal cost of debt (r_d) figure of **6.20 per cent** for use in the WACC estimate. With an inflation rate of 1.96 per cent, the corresponding real cost of debt (rr_d) is **4.16 per cent**.

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112 Access Arrangement Information, p. 27.

113 ORG, Electricity Distribution Price Determination 2001-2005, Vol 1, September 2000, p. 301.

114 ORG, Electricity Distribution Price Determination 2001-2005, Vol 1, September 2000, p. 298.

115 IPART, Final Decision, Access Arrangement for AGL Gas Networks Ltd – Natural Gas System in NSW, July 2000, p. 65.

The market risk premium

The market risk premium is a parameter in the CAPM that, together with the risk-free rate and firm-specific equity beta, determines the expected cost of equity in the business. NT Gas proposed a range of 6.0-7.0 per cent for the market risk premium. This has been the conventionally accepted range under the classical tax system. However, Professor Kevin Davis has suggested that this may not be in keeping with the forward-looking CAPM framework favoured by the Commission.[116] For example, the more stable inflationary environment now prevailing may mean that the relevant market risk premium is less than has been observed in the past. Also, following the introduction of imputation, the premium as measured in the conventional way, would have fallen to reflect the additional value of franking credits. In the Victoria *Final Decision* the Commission considered the probable range to be 4.5-7.5 per cent and chose to use a mid-value of 6.0 per cent.[117] More recently, in the *Draft Regulatory Principles*, the Commission suggested that a market risk premium of around 5 per cent may be more appropriate given the downward reassessment of the market risk premium over recent years.[118]

In its *Final Decision* on GSN,[119] IPART noted further observations (both Australian and overseas) that the market risk premium had fallen in recent years. One indicator considered by IPART was a study by Tro Kortian that estimated the equity premium to be 3.9 per cent over the period 1928-1996. Kortian's study noted that the premium had been falling over time and estimated the current equity premium to be around 3 per cent.[120] In view of this trend, IPART revised downward the market risk premium range from 6-7 per cent in the *Draft Decision* to 5-6 per cent in the *Final Decision*.[121]

The Commission accepts that there is considerable information from recent studies of financial markets suggesting that the market risk premium is now lower than it has been in past decades. The Commission considers the studies sufficiently compelling to lower the bottom end of the probable range of the market risk premium, giving a probable range of 3.5–7.5 per cent. This is a particularly large range, reflecting the uncertainty (experienced both in Australia and overseas) associated with estimating the market risk premium.

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116 Professor Kevin Davis, *The Weighted Average Cost of Capital for the Gas Industry*, report prepared for the Commission and the Office of the Regulator General, 18 March 1998, p. 14.

117 ACCC, Access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others, *Final Decision*, 6 October 1998, p. 53. See also 'Welcome to bull country', *The Economist*, 18 July 1998, pp. 17-19.

118 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p. 79

119 IPART, 'Access arrangement Great Southern Energy Gas Networks Pty Limited', *Final Decision*, March 1999, p. 24. See also IPART, 'Access arrangement Albury Gas Company Limited', *Draft Decision*, June 1999, pp. 24-25.

120 Tro Kortian, Australian Sharemarket Valuation and the Equity Premium, September 1998, Department of Finance, University of Sydney.

121 IPART, 'Access arrangement Great Southern Energy Gas Networks Pty Limited', Final Decision, March 1999, p. 24. See also IPART, 'Access arrangement Albury Gas Company Limited', Draft Decision, June 1999, pp. 24-25.

The Commission acknowledges that indications of a downward trend are not fully accepted by market participants and commentators. However, there does appear to be sufficient support to suggest that the market risk premium is now unlikely to be above 6.0 per cent. While the lower end of the range for the market risk premium remains the centre of debate, the Commission has decided to adopt the upper limit of 6.0 per cent in its WACC calculations for ABDP. This figure is at the bottom end of the range proposed by NT Gas. The Commission will reconsider the appropriate level of the market risk premium over time as each regulatory decision is made and more empirical evidence becomes available.

Level of debt funding (gearing)

NT Gas suggested that the proportion of debt funding applicable to ABDP to be 50-60 per cent.[122] The Commission notes that the Modigliani-Miller theorem suggests that the relevant cost of capital should be invariant over a broad range of gearing possibilities. Therefore the gearing assumption used for WACC purposes should not be a critical one.[123] The Commission has tested alternative gearing ratios in its model and found these alternative values to have minimal impact on the final revenues and tariffs derived from the model.

The Commission notes Standard & Poors' most recent global financial projections for global power companies. Standard & Poors' estimate that the gearing ratio for global transmission and distribution power companies lies somewhere between 55 and 65 per cent.[124] Therefore, for the purpose of deriving the WACC for the ABDP, the Commission considers a gearing ratio of **60:40** to be reasonable. This gearing ratio is consistent with the Commission's other regulatory decisions.

Utilisation of imputation credits

The availability of tax imputation credits requires a modification to the standard CAPM/WACC model to reflect the return to shareholders of tax credits associated with their share dividends. Thus, gamma (γ) is included in the WACC calculation to represent the proportion of franking credits that can, on average, be used by shareholders of the company to offset tax payable on other income. The higher the gamma, the lower the required return to equity holders and therefore the lower the estimated WACC. Consequently, gamma becomes a significant parameter.

NT Gas proposed a range of 25-50 per cent for gamma. The Commission's Victoria *Final Decision* and the *Draft Regulatory Principles* note that the analysis of imputation credits is a controversial issue and that there is considerable debate as to the value that should be ascribed. Ultimately, the Commission's choice of gamma will be a matter of judgement based on available empirical evidence.

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122 Access Arrangement Information, p. 27.

123 Modigliani and Miller establish that the value of the company is unaffected by its choice of capital structure using the principle of 'no arbitrage'. This principle states that assets that offer the same cash flows must sell for the same price. Thus, a company's borrowing decision does not affect either the expected return on the company's assets or the required return on those assets.

124 Standard and Poor's Rating Methodology for Global Power Companies, 1999, p. 4.

The analysis of imputation credits and their impact on assessed cost of capital in Australia is a developing field and thus far the measurement of the average value of Australian franking credits to the owner of Australian firms is imprecise. Estimates of the average value once distributed range from around 50 per cent to as high as 90 per cent.[125]

The Commission has considered a range of 40 to 60 per cent appropriate for the average value of Australian input credits and has used 50 per cent for the value of gamma in all its decisions on gas access arrangements to date.

However, for regulatory purposes it is debatable whether an average for the value of imputation credits is appropriate. Generally, if an average rate is used in the regulatory rate of return investors who are able to take advantage of more than the average will receive a rate of return greater than their expected rate of return. As a consequence the company's share price will bid up until the actual rate of return (based on the market value of the assets and not the regulated value) equals the required rate of return of those investors able to take the most advantage of the tax credits. Investors who are at a comparative disadvantage will either sell their shares or accept a lower rate of return. This argument tends to suggest that the appropriate value for utilisation of imputation credits for regulatory purposes should approach 100 per cent.

Furthermore, recent changes to Australia's taxation law[126] now mean that resident individuals and complying superannuation funds that previously may not have been able to receive the full benefit of franking credits, can now do so.[127] This implies a gamma of 100 per cent for domestic investors.

In light of empirical evidence and recent changes to the tax system, the Commission is of the view that it might be more appropriate to set a gamma equal to one for regulatory purposes, assuming a private Australian ownership structure. However, uncertainty still remains regarding the appropriate value of gamma and until further research is undertaken the Commission considers it appropriate to assume a gamma of 50 per cent in its Draft Decision for the ABDP.

Effective tax rate

Infrastructure owners are permitted to accelerate depreciation for tax purposes, hence tax depreciation may be significantly higher than economic depreciation. This difference between tax depreciation and economic depreciation means that there is an excess tax allowance in the early years of a project or pipeline service, resulting in a

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125 According to IPART, Australian stocks in 1998 had an average dividend pay out ratio of approximately 70 per cent. IPART, *The Rate of Return for Electricity Distribution Networks, Discussion Paper*, November 1998, p. 22.

126 On 30 June 2000 the New Business Tax System (miscellaneous) Bill 1999 received royal assent as Act 79.

127 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 franking credits being eroded. Under the new tax system, franking credits are paid to the fund as a rebate from the Australian Tax Office.

considerable deferral of any tax liabilities associated with the project. These deferred liabilities serve to improve early cash flows to the investor and improve the internal rate of return of the project above that indicated by the assumed WACC parameters. This effect results in an effective tax rate for the return on equity (T_e) that is less than the statutory rate (T) assumed by NT Gas for the CAPM/WACC framework. The effective tax rate for NT Gas derived from the Commission's cash flow model is approximately **1.53 per cent**.

In the CAPM/WACC equations there is an issue as to whether to use the statutory tax rate or the effective tax rate. This issue becomes irrelevant in the post-tax regulatory framework adopted by the Commission, as taxes are calculated on an 'as you go' basis. This involves using a post-tax WACC directly available from CAPM estimates to reflect the return on assets and to capture the impact of taxes in the cash flows. Such taxes are simply added, along with other capital costs and operations and maintenance costs, to calculate the target revenue requirement for the business. This approach avoids the need for a special conversion formula, which is discussed later, and handles tax in a very transparent way.

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

Because the Commission has adopted a post-tax regulatory framework, it is necessary to carry over aspects of historic financial accounts that impact on post-tax returns likely to be achieved in the future. Therefore, it is important that the residual asset value for tax depreciation be transferred to the post-tax framework and that tax depreciation concessions that can be used to offset future taxes are accounted for in regulated revenues.

To the extent that tax depreciation claimed in previous years may not have been fully exhausted in the reduction of tax liabilities, the amount will still be available (as a carried-forward tax loss) to reduce future taxable income. This carried-forward tax loss is calculated as the difference between depreciation for tax purposes (tax depreciation) and depreciation for accounting purposes (book depreciation) since 1986.

Identifying available tax concessions (as a carried-forward tax loss) in NT Gas's cash flows ensures that NT Gas receives an allowance for taxes over the access arrangement period in accordance with its (concession-inclusive) tax liability for the period.

This adjustment should be considered quite separately from the adjustment to the initial capital base that was discussed earlier, in section 2.2.7.

That adjustment is a direct deduction from the initial capital base of the deferred tax liability (measured as the accumulated prima facie tax expenses). This approach acknowledges that the deferred tax amount is similar to an interest free loan from the ATO or a free source of capital. It recognises that, under the post-tax regulatory framework, NT Gas will be fully compensated in regulated revenues for expenditure to meet those liabilities as they become due. In other words, the adjustment ensures that the service provider is not compensated twice for its tax liabilities.

Beta and risk

The equity beta is a measure of the expected volatility of a particular stock relative to the market as a whole. It measures the systematic risk of the stock, that is, the risk that cannot be eliminated in a balanced, diversified portfolio. Generally, the Australian Stock Exchange (ASX) is used as a proxy for the whole market. The market average being equal to 1, an equity beta of less than 1 indicates that the stock has a low systematic risk relative to the market as a whole. Conversely, an equity beta of more than 1 indicates that the stock has a relatively high risk.

Where an equity beta is calculated for a particular company, it is only applicable for the particular capital structure of the firm. A change in the gearing will change the level of financial risk borne by the equity holders. Hence the equity beta will change. There is a common method to enable beta to be compared across companies with different capital structures. The approach is to derive the beta that would apply if the firm were financed with 100 per cent equity, known as the 'asset' or 'unlevered beta'. The analyst can then calculate the equivalent equity beta for the level of gearing. This technique is known as 're-levering' the asset beta.

NT Gas has proposed an asset beta (β_a) range of 0.55–0.90 and an equity beta (β_e) range of 1.25-1.65. When calculating the equity beta NT Gas states that it contrasted the results derived from the Monkhouse, Davis and CSFB formulas. Although the actual results of each of the calculations were not provided in the access arrangement information, NT Gas noted that the resulting equity betas 'were similar when identical inputs were used'.[128]

As outlined in section 2.5.2, NT Gas made several observations relating to its perception of the higher risk of ABDP compared to the Victorian gas transmission system, in which the Commission adopted an asset beta of 0.55 and an equity beta of 1.20. Given that the ABDP is fully contracted until 2011 it is difficult to accept the submissions by NT Gas that the pipeline faces higher risks than the TPA in Victoria. Notwithstanding this, the Commission does not consider that the factors outlined by NT Gas impact on beta (which measures systematic risk).

Under the CAPM assumptions, the equity beta is meant to reflect only market-related or non-diversifiable risks. However, in the assessment process for the Victorian transmission systems, it was suggested in the public debate that increasing the value of beta could accommodate an allowance for unique (diversifiable) risks. An increase in the equity beta would only be justified if there were a downside bias in the unique risks faced by the business.

It is often argued that greenfields projects require a higher beta and therefore higher WACC. The Commission notes that in its original access arrangement for the Central West Pipeline AGL proposed a pre-tax real WACC range of 9 to 9.5 per cent (which was subsequently revised down to 7.78 per cent to comply with the Commission's

[128] Access Arrangement Information, p. 28

required amendments).[129] This is significantly less than the 11 per cent WACC proposed by NT Gas for the ABDP.

It is the Commission's view that risks such as those cited by NT Gas should be dealt with by way of accelerated depreciation rather than the WACC. The Commission considers that the accelerated depreciation allowance substantially compensates for the risks associated with the ABDP. It does this by providing a substantial return of capital to NT Gas by 2011 (excluding residual value).

Submissions to the Victorian access arrangement suggested that the 'newness' of the regulatory framework introduced perceived uncertainties on the part of investors. Submissions suggested that these uncertainties be taken into account via an increase in the beta value in setting the cost of capital. Whilst this treatment is no longer considered appropriate, the Commission took this argument into account at the time and assessed an asset beta of 0.55 as being appropriate for the Victorian system.

The Commission also notes the findings of a report prepared by Professor Kevin Davis for the South Australian Independent Pricing and Access Regulator (SAIPAR) on the WACC proposed by Envestra Limited for its distribution network in South Australia. Like NT Gas, Envestra[130] argued for a higher WACC than that for the Victorian distribution network on the basis of:

- slower market growth;
- a more concentrated customer base and therefore greater variability of demand; and
- greater competition from alternative fuel sources.

Professor Davis considered that none of these arguments provides any rationale for assuming greater systematic (non-diversifiable) risk.[131] According to Professor Davis, slower market growth does not imply any higher systematic risk. Rather, it will imply, through the determination of target revenues that return a stated rate of return on capital, that the average price received will be higher for a given asset base.[132] Further, there is no *a priori* reason to expect that a more concentrated customer base, and therefore greater variability of demand, leads to a greater correlation of demand with market returns.[133] Finally, greater competition from alternative fuel sources has no obvious implications for the assessment of systematic risk.[134] Professor Davis

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129 ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision*, 30 June 2000, p.15.

130 Envestra Limited, *Access Arrangement Information for the South Australian Distribution System*, 22 February 1999, Appendix B, p. 4.

131 Kevin Davis, *The Weighted Average Cost of Capital for Access Arrangements for Envestra – A Report prepared for the SAIPAR*, 20 October 1999, p. 7.

132 If two assets with the same initial cost and equivalent risk are to both be zero NPV projects, the one with a lower output level must generate a higher price per unit of output.

133 An increase in total risk can occur from an increase in non-systematic risk without there being any change in beta.

134 Kevin Davis, *The Weighted Average Cost of Capital for Access Arrangements for Envestra – A Report prepared for the SAIPAR*, 20 October 1999, p. 7.

concluded that there would appear to be no obvious reason to assume a higher asset beta for the South Australian market than for Victoria.[135]

In view of these considerations, the Commission proposes an asset beta of **0.50** as appropriate for the ABDP.

In addition to assessing the level of systematic risk facing the ABDP, the Commission has relied on a combination of empirical evidence and regulatory precedence in determining an asset beta of 0.50 for the ABDP.

A recent study undertaken by NERA into international regulated rates of return found that asset betas set by regulators in the UK are consistent with the Commission's proposed asset beta of 0.50. NERA stated:

> Explicitly reported asset betas in the UK and those implicit (given assumed regulatory gearing ratios) would appear to be around or less than 0.5. This is consistent with the Australian average of 0.48.[136]

A survey of US and UK asset betas was undertaken by the ORG as part of its *Electricity Distribution Price Determination 2001-2005*. The ORG estimated the average asset betas for proxy groups of companies in the UK, US and Australia.[137] The ORG concluded that for a debt beta of zero, the average asset beta ranged from 0.22 to 0.37 in Australia, 0.19 to 0.40 in the UK and between 0.15 to 0.35 in the US.[138] These estimates would be slightly higher with a debt beta of 0.06, as has been assumed by the Commission.

With this empirical evidence in mind and an understanding of the complexities associated with comparing international asset betas, the Commission is of the view that an asset beta of 0.50 is appropriate for the ABDP. The Commission also notes that this is consistent with recent regulatory decisions in Australia. The following table compares the asset betas established by IPART, the ORG and the ACCC in respect of transmission and distribution gas and electricity businesses over the past three years.

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135 Kevin Davis, *The Weighted Average Cost of Capital for Access Arrangements for Envestra – A Report prepared for the SAIPAR*, 20 October 1999, p. 7.

136 NERA, International Comparison of Utilities' Regulated Post Tax Rates of Return in: North America, the UK and Australia, March 2001, p.19.

137 Equity betas were provided by Bloomberg (US,UK, Aust), Ibbotson (US), the London Business School (UK) and the Australian Graduate School of Management Risk Measurement Service(Aust).

138 The location of the averages within these ranges is dependent upon which adjustment (eg. Blume, Vasicek) was considered appropriate. For a detailed discussion of these adjustments, see ORG's *Electricity Distribution Price Determination 2001-2005*, Vol 1, pp. 275-9.

Table 2.10: Comparison of Asset Betas

Regulatory Decision	Asset Beta
ACCC – SMHEA Transmission Network (Feb 2000)	0.30-0.50
ORG – Vic Electricity Distribution (Sept 2000)	0.38
ACCC – Moomba Sydney Pipeline (Dec 2000)	0.50
ACCC – Moomba Adelaide Pipeline (Aug 2000)	0.50
IPART – AGLG GN Final Decision (Jul 2000)	0.40-0.50
ACCC – Central West Pipeline (Jun 2000)	0.60
ACCC – Transgrid (Jan 2000)	0.35-0.50
IPART – AGL (ACT) Gas Network (Jan 2000)	0.40-0.50
IPART – Electricity Distribution (Dec 1999)	0.35-0.50
IPART – Albury Gas Company (Dec 99)	0.40-0.50
IPART – GSN (Mar 1999)	0.4-0.5
ORG – Vic Gas Distribution (Oct 1998)	0.55
ACCC – Vic Gas Transmission (Oct 1998)	0.55

In recent decisions the Commission has suggested a range for the debt beta of 0.00 to 0.06. The Commission proposed a debt beta of 0.06 in the MAPS and MSP *Draft Decisions*. The Commission considers that a debt beta of 0.06 is also appropriate for the ABDP. As a result, the equity beta (β_e) for the ABDP is **1.16**.

Asymmetric risk and self insurance

In addition to outlining the additional risks it sees facing the ABDP, NT Gas has included margins for asymmetric risk and self insurance risk in its calculation of the nominal cost of equity.

NT Gas estimated a margin of 0.0-1.0 per cent for asymmetric risk and a margin of 0.0-0.5 per cent for self insurance costs. NT Gas did not provide further reasoning or empirical support for the proposed margins.

A similar adjustment to the cost of equity to allow for asymmetric risk and self insurance was proposed by AGLP in its CWP access arrangement. AGLP argued that it faced a significant asymmetry in specific risks and this should be reflected in a higher return. However, the Commission noted that while AGLP had drawn attention to its downside risks, it had made comparatively little assessment of any upside benefits. In the case of the CWP, upside benefits included those available as a result of the incentive based arrangements operating in the regulatory framework and the reduction in the company tax rate from 36 per cent to 30 per cent.[139]

In the case of NT gas, the Commission acknowledges that because the ABDP is fully contracted there is little scope for NT Gas to grow the market. Consequently upside benefits are most likely to arise as a result of achieving less than forecast operating and maintenance expenditure. However, while there may be little upside benefits available, the Commission believes that NT Gas faces virtually no downside risks. As the pipeline is fully contracted until 2011, there are no volume risks. Further, the Commission is proposing an accelerated depreciation schedule that provides a substantial return of pipeline capital to NT Gas by 2011.

On the issue of insurable risks, NT Gas states that the ABDP is subject to a higher level of natural and force majure style risks (eg. flooding, earthquake, lightening strikes) than many other pipelines and an allowance for self insurance cost should therefore be added to the cost of equity. The Commission considers that, where those risk can be substantiated, it may be appropriate to recognise the risk of self insurance in the cash flows.

In its CWP Final Decision the Commission provided for an asset beta of 0.6, considered to be at the high end of a plausible range, to accommodate for the asymmetric and self insurance risks raised by AGLP.[140] However, in that case the asset beta adjustment was motivated by a recognition that some of the asymmetric risks were linked to market uncertainties and likely to be correlated with changes in general economic conditions. In the case of NT Gas the pipeline is fully contracted for the duration of the access arrangement and market related uncertainties are minimal. The Commission considers that compensation for self insurance risks in addition to those already covered by insurance should be quantified and included in the cash flows (as an operating cost) rather than as a premium in the calculation of the WACC.

Many risks of the nature described by NT Gas are insurable and are captured as insurance premiums forming part of the operating and maintenance cost of the business. Further, the Commission would only consider it appropriate to incorporate an additional allowance for self insurance if it can be demonstrated that there are remaining risks which the service provider self insures against.

The Commission has not included an allowance for self insurance in its cash flow analysis, however, it may reconsider the issue of self insurance pending further substantive and quantitative evidence from NT Gas to support its inclusion. The Commission would also welcome any comments from interested parties on the issue.

Calculation of the rate of return

Table 2.11 summarises the parameter values proposed by NT Gas in its access arrangement information and by the Commission in this Draft Decision.

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[139] ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision,* 30 June 2000, p.30.

[140] ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision,* 30 June 2000, p.30.

Table 2.11: Comparison of WACC parameters used by NT Gas and Commission

CAPM parameter	NT Gas proposal	Commission Draft Decision
Real risk-free rate (rr_f) %		2.98
Expected inflation rate (f) %	2.0-3.0	1.96
Nominal risk-free rate (r_f) %	5.5-5.9	5.00
Cost of debt margin (DM) %	1.0-1.40	1.20
Cost of debt (r_d) %	6.5-7.6	6.20
Real cost of debt (rr_d) %	n/a	4.16
Market risk premium (r_m-r_f) %	6.0-7.0	6.0
Debt funding (D/V) %	50-60	60
Usage of imputation credits (γ) %	25-50	50
Corporate tax rate (T) % [(a)]	36	30
Effective tax rate (T_e)	36	1.53
Asset beta (β_a)	0.55-0.90	0.50
Debt beta (β_d)	n/a	0.06
Equity beta (β_e) [(a)]	1.25-1.65	1.16

Source: Access Arrangement Information, p. 26 and Commission analysis.

Note: (a) The Commission uses the Monkhouse formula as follows:

$$\beta_e = \beta_a + (\beta_a - \beta_d)(1 - r_d/(1+r_d)T_e).D/E.$$

This formula assumes an active debt policy aimed at maintaining a specific gearing ratio.

The parameter values used by the Commission are those considered most appropriate for the ABDP as a stand-alone business. These generally fall near the middle of a narrow range based on the information available.

NT Gas chose to convert the nominal post-tax WACC to a pre-tax WACC by first adjusting for tax then inflation. The Commission does not consider such an approach valid where the corporate tax rate is used. The conversion formula requires the use of an effective tax rate and the rate of inflation. These are both a source of uncertainty over the long term.

Table 2.12 below shows the WACC figures proposed by NT Gas in its access arrangement and the Commission in this Draft Decision.

Table 2.12: WACC estimates based on parameters given in Table 2.11.

	per cent	
	NT Gas proposal	**Commission Draft Decision**
Nominal cost of equity $r_e = r_f + \beta_e (r_m - r_f)$	14.3-17.3	11.96
Nominal pre-tax cost of debt (r_d)	6.7-7.4	6.20
Nominal vanilla WACC $W_n = r_e.E/V + r_d.D/V$	n/a	8.51
Post-tax nominal WACC $W = r_e [(1-Te)/(1-Te(1-\gamma))].E/V + r_d (1-T).D/V$	6.5-10.9	7.35
Post-tax real WACC $W_r = (1+W)/(1+f) - 1$	n/a	5.28
Pre-tax nominal WACC $W_t = r_e /(1-Te(1-\gamma)).E/V + r_d .D/V$	10.2-17.0	8.54
Pre-tax real WACC	8.5-11.7[(a)]	6.49[(b)]
Pre-tax nominal WACC – cash flows (W_{trci})	n/a	8.59[(b)]
Implied tax wedge $= W_{trci} - W_n$	n/a	0.08

Source: Access Arrangement Information, p. 26 and Commission analysis.

Note: (a) calculated by NT Gas using the forward transformation formula: $W_{tr} = (1+W_t)/(1+f)-1$
(b) obtained from the Commission's cash flow analysis.

In calculating the post-tax revenue requirement that is consistent with the nominal cost of equity established by the CAPM, the return on capital has been calculated using the nominal vanilla WACC. Taxes have been addressed specifically in the cash flows as they arise.

The nominal vanilla WACC can be defined as the weighted-average cost of debt and equity before any adjustments for tax and inflation. In other words, it represents the most basic post-tax return required by the business after all costs have been paid. That is it covers the post-tax cash flow required by equity holders and interest payments on debt.

The difference between the nominal pre-tax WACC and the nominal vanilla (post-tax) WACC is represented by the 'tax wedge'. The tax wedge has been used by the Commission to normalise tax payments over the life of the assets. This approach is discussed below in section 2.7.4.

Given the known shortcomings of the conversion formulae, the Commission has replicated the post-tax cash flows in a pre-tax framework to find the pre-tax real WACC that is consistent with the nominal cost of equity.

The Commission has found that a pre-tax real WACC of **6.49 per cent** is consistent with a post-tax nominal cost of equity of 11.96 per cent.[141]

While 12 per cent is the expected post-tax cost of equity under the assumptions of the regulatory framework, this is a long-term expectation. In reality, returns may vary from year to year and can be expected to exceed this benchmark under the incentive provisions of the access arrangement.

Proposed Amendment A2.6

In order for NT Gas' access arrangement for ABDP to be approved:

- the WACC estimates and associated parameters forming part of the access arrangement must be amended to reflect the current financial market settings, by adopting the parameters set out by the Commission in Table 2.11 and Table 2.12; and
- the target revenues and forecast revenues must be based on these new parameters.

Given the resulting scope for variation between the key rates of return, it is important to note the assumptions made to arrive at the Commission's outcome. The model used is strictly in line with the regulatory framework proposed by the Commission. Post-tax cash flows have been assessed over the remaining life of the ABDP, that is, 67 years. Asset values, operating and maintenance costs, capital expenditure and financial parameters are as specified in this Draft Decision. Capital expenditure beyond the access arrangement period has not been included in the model because the Code requires the Commission to set a rate of return on the value of the assets that form the covered pipeline (capital base), that is, on the value of the existing assets plus capital expenditure during the access arrangement period.[142] Asset values beyond the access arrangement period have been indexed by the estimated rate of inflation. The Commission has used NT Gas' forecast operating and maintenance cost, as given in its financial model until 2011[143] and indexed operating and maintenance costs by the estimated rate of inflation thereafter.

2.6 Non-capital costs

2.6.1 Code requirements

The Code (sections 8.36 and 8.37) allows for recovery of the operating, maintenance and other non-capital costs that a prudent service provider, acting efficiently and in accordance with good industry practice, would incur in providing the reference service.

141 While these amounts have been applied to the revenue model, they have been referred to in rounded terms (6.5 and 12 per cent respectively) elsewhere in this Draft Decision.

142 Code section 8.4(a).

143 The financial model provided to the Commission by NT Gas accounted for the period 1999 to 2011.

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

2.6.2 NT Gas' proposal

NT Gas aggregated forecasts of non-capital costs and historical costs to arrive at best estimates for this access arrangement period.

Table 2.13: Total Operating Costs 1999-2004

Year Ending June 30 ($'000)	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Operations & maintenance	5469	5354	5481	5764	5836	6022
Administration & general	1126	1226	1258	1289	1321	1354
Sales and marketing	128	131	134	138	141	145
Total Operating Costs	**6723**	**6711**	**6873**	**7191**	**7298**	**7521**

Source: Access Arrangement Information, p. 35.

All of the operating and maintenance costs are direct costs and are to be recovered from reference tariffs on the basis of length of pipeline operated in each of the three pricing zones. Administration and general costs are allocated on the same basis, while sales and marketing costs are allocated on the basis of the quantity of gas delivered.[144]

2.6.3 Submissions by interested parties

The joint NT Government and PAWA submission was the only submission to comment on the forecast operating and maintenance costs proposed by NT Gas. PAWA noted that operating costs have 'been a bone of contention' between PAWA and NT Gas since 1986.[145] In particular:

> ...NT Gas' operations and maintenance costs for the Pipeline are unreasonable and do not represent the efficient costs of delivering the reference service in accordance with global best practice.[146]

2.6.4 Commission's consideration

Two industry accepted benchmarks for operations and maintenance costs are cost per pipeline length and cost per volume transmitted. Comparisons between the ABDP and other transmission pipelines in Australia are shown in Table 2.14 below. In terms of cost per 1 000km, the ABDP compares favourably with the other pipelines. However,

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[144] Access Arrangement Information, p. 35.

[145] NT and PAWA Submission, 17 November 1999, p. 8.

[146] NT and PAWA Submission, 17 November 1999, p. 8.

in terms of cost per GJ, the ABDP appears to be more expensive to operate than other pipelines.

It must be noted that while these measures of pipeline cost efficiency have been accepted in the industry, they do have limitations. The comparisons can be made, but in doing so other aspects of the pipelines such as compression, age and throughput should generally be noted.

Table 2.14: Comparison of transmission pipeline non-capital costs

	$/1 000km ($m)	**$/GJ**
NT Gas – ABDP (1999)[a]	3.9	0.42[d]
EAPL – MSP (2001)[b]	6.1	0.12
Epic – Moomba-Adelaide Pipeline (1999)[c]	19.2	0.16
TPA – Victorian transmission systems (1998)	16.0	0.13
AGLP – CWP (1999)[e]	2.8	2.62
AGLP – CWP (2004)[e]	2.8	0.52

Notes: (a) NT Gas, Access Arrangement Information, p. 46.
(b) EAPL, Proposed Access Arrangement Information, p. 65.
(c) Epic, Proposed Access Arrangement Information, attachments 1 & 4.
(d) Total operating costs divided by total throughput, Access Arrangement Information, pp. 36 & 41.
(e) AGLP, Revised Access Arrangement Information, pp. 27-31. 2004 figures based on forecast throughputs.

The higher $/GJ measure calculated for NT Gas may be attributed to the differences in capacity/throughput between the pipelines and the subsequent economies of scales inherent in larger capacity pipelines. For example, while both the ABDP and MAPS are fully contracted, the current capacity for each of the pipelines is approximately 16 PJ and 95PJ[147] per year respectively.

Another measure that is sometimes employed is to determine forecast operating costs as a percentage of the overall capital assets employed.[148] Typically, results range from 2 per cent for an uncompressed pipeline to 5 per cent for a fully compressed pipeline. In NT Gas' case, forecast operating costs are approximately 2.2 per cent of the ORC value calculated by the Commission. On this measure, the Commission considers NT Gas' forecast costs to be reasonable.

Chapter 4 of this Draft Decision discusses the use of key performance indicators (KPIs) and performance benchmarks in more detail. It concludes that, on the basis of the available information and KPIs, the operating, maintenance and other non-capital costs for the ABDP are reasonable.

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[147] Epic Energy's Access Arrangement Information for MAPS, p. 36.

[148] In the interests of comparison between pipeline systems, the ORC figure may be used as a measure of the value of the capital assets employed.

In line with the Commission's assessment of NT Gas' revenues over the five-year period commencing 1 July 2001, total operating costs for 2005 to 2006 were obtained from data in NT Gas's financial model for the ABDP (Table 2.15). As with forecast capital expenditure, NT Gas will be given the opportunity to provide the Commission with a revised estimate for operating costs for 2005-2006 prior to the release of the Final Decision.

Table 2.15: Total Operating Costs 2005-2006

Year Ending June 30 ($'000)	**2005**	**2006**
Operations & maintenance	7333	6327
Administration & general	1388	1423
Sales and marketing	149	152
Total Operating Costs	**8870**	**7902**

Source: NT Gas' financial model for the ABDP.

2.7 Forecast revenue

2.7.1 Code requirements

As noted previously, the Code (section 8.4) sets out three alternative methodologies for determining total revenue. In this access arrangement, the service provider has proposed to use a cost of service methodology. Total revenue is calculated as the return on the value of the capital base, depreciation of the capital base plus the operating and maintenance and other non-capital costs incurred in providing its services over the covered pipeline.

2.7.2 NT Gas' proposal

NT Gas did not anticipate that any revenue would be generated from the sale of the reference service or negotiated service during the access arrangement period, because the capacity of the ABDP is fully committed to users under pre-existing transportation contracts.[149] Furthermore, NT Gas contended that the revenue being earned by NT Gas under those pre-existing contracts is less than the total revenue NT Gas is likely to be entitled to recover under the Code.[150]

NT Gas also considered that there is great uncertainty regarding the usage of, and hence revenue from, the rebatable service and has made no provision for this in its forecast of total revenue. NT Gas' forecasts for total revenue reflect the amounts to be generated from selling current contracted throughput at the proposed reference tariffs over the access arrangement period. This is provided in Table 2.16 below.

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149 Access Arrangement Information, p. 30.

150 Access Arrangement Information, p. 30.

Table 2.16: Forecast revenue, NT Gas proposal, 2000 to 2004

	Forecast revenue ($m)	
Year ending 30 June	**Real dollars[(a)]**	**Nominal dollars**
2000	52.7	54.0
2001	52.1	53.4
2002	52.0	53.3
2003	51.6	52.9
2004	51.5	52.8

Source: ACCC calculations from data in the Access Arrangement Information, p.30.
Note: (a) assumes an inflation rate of 2.5 per cent.

NT Gas was also given the opportunity to respond to NTPG's submission (discussed below) that PAWA is required to fund a second compressor station. NT Gas stated:[151]

> Where a party (including PAWA) has capacity requirements which require an additional compressor, that party will be responsible for funding the installation of the compressor. In respect of any obligation which may exist under the Gas Sales Agreement for PAWA to fund another compressor, this is a confidential contractual matter between NT Gas and PAWA and is not an appropriate matter for third parties to seek to enforce through the access arrangement.

2.7.3 Submissions from interested parties

PAWA noted that the statements made by NT Gas are consistent with PAWA's understanding that there is no firm capacity presently available on the pipeline without further compression.[152] PAWA also submitted that although there is likely to be some interruptible capacity available, given that the significant current market for gas in the NT is for electricity generation, peak gas and electricity demand periods are likely to be the same for most users.[153]

NTPG submitted that the existing lease obligations provide for PAWA (the foundation customer) to fund an adequately sized second compressor. NTPG claimed that if an additional compressor were installed, then extra capacity would be made available for sale under the reference service tariff during the access arrangement period. NTPG also suggested that failure to install the second compressor would represent a strategic move by PAWA to lessen potential competition in the electricity industry.[154]

NTPG contended that:

> were ABDP pipeline capacity actually to become a significant factor preventing the sale of the Reference Service, it would be the consequence of NT Gas choosing not to request PAWA's installation of additional compressor capacity on a timely basis. Such a scenario of events would be

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151 Email from Agility Management, on behalf of NT Gas, to Commission staff, 27 March 2001.

152 NT and PAWA Submission, 17 November 1999, p. 3.

153 NT and PAWA Submission, 17 November 1999, p. 3.

154 NTPG submission, 12 September 1999, p. 6.

> consistent with PAWA's apparent strategic business interest in creating barriers to entry for potential competitors in the electricity industry.[155]

In reply, PAWA rejected that it has any immediate obligation to fund another compressor.[156]

2.7.4 Commission's considerations

NT Gas applied a cost of service framework to determine total revenue as permitted by section 8.4 of the Code.

As a result of the Commission's amendments proposed for the WACC, inflation and tariffs, the forecast regulated revenue path for the ABDP will be different to that proposed by NT Gas. Given that the access arrangement was submitted in 1999, the Commission has updated its forecast revenues to reflect the five-year period commencing 1 July 2001. In doing so, the Commission has allowed for capital expenditure, additional depreciation of the asset base and accounted for actual inflation since 1 July 1999.[157] The forecast revenues resulting from the Commission's analysis are provided in Table 2.17 below.

Table 2.17: Commission's Forecast revenue for 2002 to 2006

Year ending 30 June	Forecast revenue ($m)
2002	29.9
2003	29.6
2004	30.2
2005	30.1
2006	29.9

Source: ACCC calculations.

According to NT Gas, the ABDP currently has no available firm capacity and only a small amount of interruptible capacity. Given this, NT Gas is expected to earn its revenues primarily from it existing haulage agreements, with little or no revenue accruing from negotiable or interruptible services. Faced with the difficulty of estimating revenues arising from interruptible and negotiated services, and the likelihood of low or non-existent sales of the transportation service, the Commission has assessed NT Gas' total revenue for the purposes of section 8.2 as if it were to account for 100 per cent of NT Gas' total revenue.

[155] NTPG submission, 12 September 1999, p. 6.

[156] NT and PAWA Submission to, 17 November 1999, p. 3.

[157] The actual inflation rate of 3.2 per cent was used for the year ending 30 June 2000 and a forecast inflation rate of 1.96 per cent was used thereafter.

As outlined in the ACCC's *Application of the Price Exploitation Guidelines to regulated industries: the process,*[158] an adjustment for the GST impact on CPI is necessary to ensure that regulated business operating under a CPI-X annual revenue adjustment mechanism do not receive a windfall gain. This would occur if the business were to adjust its prices by a GST inclusive CPI figure in addition to receiving compensation via the pass through of the GST in its prices.

The Commission's stated position on the CPI adjustment is that it would deduct from the CPI the most up to date official Treasury forecast of the GST impact.[159] At the time the Commission released its guidelines, the GST was predicted to create a 2.75 per cent rise in the CPI between July 2000 and July 2001.[160] Since then, the predicted impact of the GST on CPI has been revised downward to 2.5 per cent.

In modelling NT Gas' regulated revenues for the access arrangement period, the Commission has applied CPI indexation that is exclusive of the GST impact on CPI (2.5 per cent) between July 2000 and July 2001.

Further, in order to comply with the Commission's GST pricing guidelines,[161] NT Gas was required to ensure that all net cost savings from the NTS were passed on to customers. Early last year, NT Gas undertook a preliminary review of cost savings resulting from the introduction of the New Tax System in respect of each of its customers. Based on these savings, NT Gas calculated an indicative GST pass through amount of approximately 9.59 per cent (that is, charges increased by 9.59 per cent on 1 July 2000).[162] The Commission considered this figure reasonable and on 9 August 2000 approved the pass through amount of 9.59 per cent for the ABDP.

Normalisation of tax payments and 'CPI-X' revenue smoothing

In establishing the cost of service revenue requirement, the Commission has normalised NT Gas' tax payments over the life cycle of the asset to remove the 's-bend' phenomenon.[163] This arises under the post-tax framework because the regulatory revenue stream provides compensation for actual tax liabilities as they occur. As a result, the profile of that revenue stream will initially be low when the firm takes advantage of available tax concessions such as accelerated depreciation, and will become much higher as those concessions expire and tax liabilities become payable. Therefore the objective of normalisation is to ensure that customers do not, as a result of higher tax payments that will need to be made in a later period, have to pay a

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158 ACCC, *Application of the Price Exploitation Guidelines to regulated industries: the process*, March 2000.

159 ACCC, *Application of the Price Exploitation Guidelines to regulated industries: the process*, March 2000, p. 6.

160 Source: Treasury mid year estimates November 1999.

161 ACCC, *Price Exploitation and the New Tax System*, March 2000.

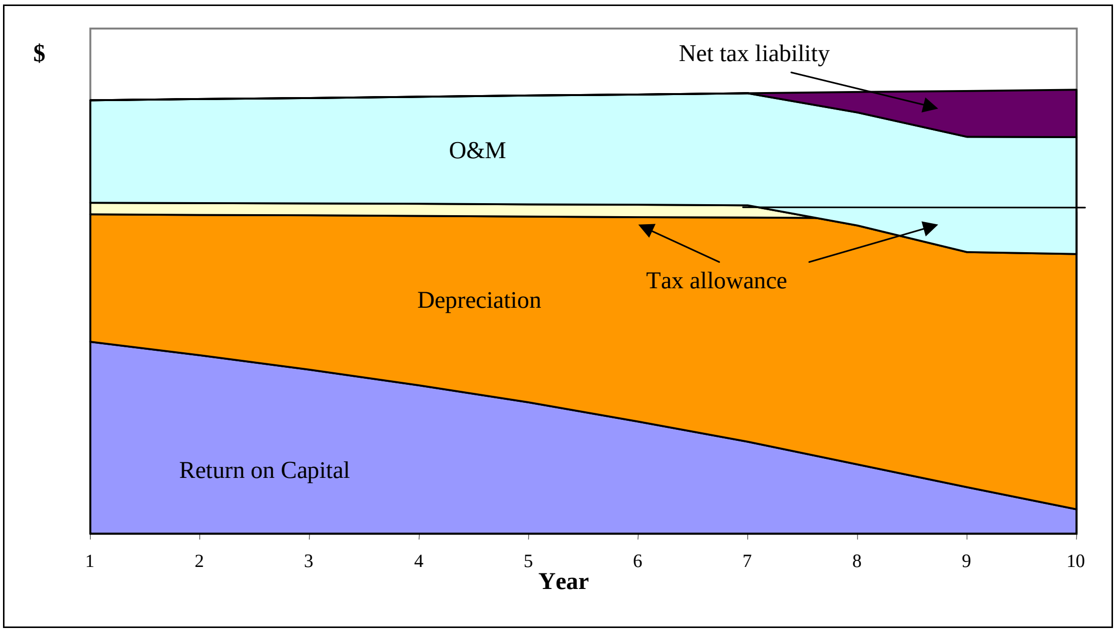
162 Letter from AGL to Commission dated 21 July 2000.

163 A detailed discussion of the 's-bend' problem is provided in Attachment B to ACCC, 'NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04', *Final Decision*, January 2000, and Attachment C to ACCC, 'Access Arrangement by AGC, Pipelines (NSW) Pty Ltd for the Central West Pipeline, *Final Decision*, June 2000.

disproportionately higher charge for services produced by the assets at that time. To normalise tax liabilities the Commission has included in the post-tax revenue requirement a factor that, in effect, represents additional depreciation (return of capital) that accumulates initially and subsequently reduces when taxes become payable and enter the cash flows. This allowance is calculated as the tax wedge[164] multiplied by the asset base less the net tax liability in each year. This ensures that when taxes enter the cash flows there is no sudden increase in the revenue requirement and therefore reference tariff.

Tax normalisation is represented in the following diagram. The top line in the diagram represents the normalised post-tax revenue stream.

Figure 2.3: Normalised post-tax revenue stream



As discussed later in section 0, the Commission has calculated a smoothed tariff path for each of the three zones during the access arrangement period. The total forecast revenue shown in Table 2.17, is based on the smooth tariff path set out in Table 2.19 (section 2.9.4) and NT Gas' volume forecasts for the access arrangement period. Amendments proposed in this Draft Decision would result in a regulated revenue stream over the access arrangement period that is approximately 45 per cent less than that proposed by NT Gas.

2.8 Cost allocation and tariff setting

2.8.1 Code requirements

Section 8.38 of the Code requires that, to the maximum extent that is commercially and technically reasonable, reference tariffs recover all costs directly attributable to the

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164 Equal to the difference between the nominal vanilla WACC and the nominal pre-tax WACC that has been derived from the Commission's cash flow analysis.

reference service and a fair and reasonable share of joint costs. The Code (section 8.42) requires that a particular user's share of reference service revenues recover costs according to the same principles.

2.8.2 NT Gas' proposal

In its access arrangement, NT Gas stated that tariffs would be charged on the basis of throughput (dollar per GJ of throughput). Where the quantity of gas transported for a user is less than 80 per cent of annual contract quantity (ACQ) in a contract year, the user will pay an amount equal to the charge for delivery of 80 per cent of ACQ in that contract year.[165]

NT Gas proposed to allocate total revenue across the following 3 pricing zones:

- Zone 1 – Amadeus Basin to Warrego (730 km)
- Zone 2 – Warrego to Mataranka (521 km)
- Zone 3 – Mataranka to Darwin (407 km)

Total operating costs are generally allocated to each zone on the basis of length of pipeline operated in each zone. The return on capital and return of capital (depreciation) are allocated on the basis of the proportion that the ORC of pipeline assets in each zone bears to the total ABDP ORC as at 30 June 1999.

NT Gas claimed that the introduction of zonal pricing is an attempt to develop the market for pipeline services and to replicate the outcome of a competitive market. Under the proposed tariff structure, receipt and delivery of gas to any point within a zone is charged at the throughput tariff applicable to that zone. Should gas be transported across two or more zones, then the throughput charge is the sum of the relevant throughput tariffs for each of those zones.[166]

NT Gas considered that the adoption of zonal tariffs is more cost-reflective of a user's utilisation of the pipeline than a single postage stamp tariff (existing), while avoiding the complexities and expense of administering a strictly distance based tariff.[167]

2.8.3 Submissions from interested parties

Several submissions commented on NT Gas' proposed zonal tariff regime and the level of the proposed tariffs. NTPG and Santos both stated that the zonal pricing structure is discriminatory, and that more efficient prices would be set on the basis of distance transported, or \$/GJ/km.[168]

Santos pointed out that under the proposed zonal prices, the same tariff applies for gas transportation 407 kilometres from Mataranka to Darwin as would apply for 30

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165 Access Arrangement, pp. 3 & 11

166 Access Arrangement Information, p. 7.

167 Access Arrangement Information, p. 7.

168 NTPG submission, 12 September 1999, p. 12 & Santos submission, 17 September 1999, p. 4.

kilometres from an injection point near Darwin.[169] NTPG also raised this concern, stating that the reference tariff fails to reflect ‘efficient’ costs of delivering transportation services as required by the Code.[170]

NTPG also noted that the zonal pricing structure creates a locational cost advantage for power plants situated closest to the Darwin electricity market over more distant generating plants. NTPG argued:

> A distance rather than zonal based tariff policy would do much to create a level playing field in the Katherine-Darwin energy grid, and counter market power presently stemming from Channel Island’s location relative to electricity demands which are concentrated in the Darwin area.[171]

NTPG also submitted that the proposed reference tariff of $3.63/GJ (Zone 3) is unacceptably high. In particular,

> The proposed level of Reference Tariff is excessive and will discourage prospective users. This appears a deliberate pricing policy to ensure the expectation…that *“NT Gas does not anticipate that any revenue will be generated by the sale of the Reference Service”* becomes a self-fulfilling prophecy.[172]

Furthermore, NTPG argued that if the tariff regime was based on shipping distances rather than the arbitrary zonal approach, the tariff would become $1.23 per GJ shipped 1000km on the ABDP system.[173]

2.8.4 Commission considerations

Tariff Structure

The Commission notes that existing contracts on the ABDP incorporate a ‘postage-stamp’ tariff, that is, a single tariff applies for receipt and delivery of gas at any point along the pipeline. NT Gas considers that potential users most affected by postage stamp pricing are those with price sensitive projects located part way along the pipeline, which would be charged for delivery of gas as if that gas was transported the entire length of the pipeline.[174]

The zonal tariff structure proposed by NT Gas creates three postage stamp tariffs in the place of the existing single tariff, with gas transportation charges varying between each zone. Thus, two customers in the same zone would still pay the same price, regardless of the distance gas is transported within that zone.

While the Commission considers zonal tariffs an improvement on postage stamp pricing, zonal pricing still has the potential to result in inefficient pricing signals. As noted by NTPG, a user located in zone three would be charged the same tariff

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169 Santos submission, 17 September 1999, p. 4.

170 NTPG submission, 12 September 1999, p. 12.

171 NTPG submission, 12 September 1999, p. 13.

172 NTPG submission, 12 September 1999, p. 12.

173 NTPG submission, 12 September 1999, p. 12.

174 Access Arrangement, p.6.

regardless of whether they are located in Katherine or 300km further along the pipeline in Darwin.[175]

Generally, the Commission considers that distance based tariffs are the most efficient means of charging for gas transportation. However, when making its assessment the Commission must weigh the benefits of distance based tariffs against the additional costs of determining and administering a distance based pricing regime. Given that the majority of the ABDP's customers are located towards the end of the pipeline, the practical difference between distance based pricing and zonal pricing is likely to be minimal.

Consequently, the Commission considers zonal pricing a reasonable methodology for determining tariffs for the ABDP at this stage. However, the Commission seeks further comment from interested parties regarding the potential benefits and costs associated with distance based pricing. The Commission intends to conduct further analysis of the potential price distortion created by NT Gas' proposed tariff structure in light of any information supplied by interested parties in response to this Draft Decision.

Allocation of costs

In determining its proposed tariff schedule the Commission used the same methodology as NT Gas for the allocation of costs to each zone. Under this approach:

- sales and marketing costs are allocated based on the quantity of gas delivered in each zone;
- all other operating costs are allocated based on pipeline length; and
- return on capital and return of capital are allocated on the proportion of ORC the pipeline assets in each zone represents in relation to the total ORC.

In calculating the tariffs the Commission has also utilised its own estimates of ORC for the pipeline assets in each zone, resulting in slightly different ORC proportions for Zone One and Zone Three. This leads to an increase in the Zone One tariff and a reduction in the Zone Three tariff of approximately 3 cents per GJ. While the effect on tariffs from adjusting the ORC proportions are minimal, the Commission considers that every effort should be made to ensure that the tariffs are consistent with the new ORC valuation, and are as cost reflective as possible.

Proposed Amendment A2.7

In order for NT Gas' access arrangement for the ABDP to be approved, the ORC valuations for each zone used for the calculation of tariffs should be amended as follows:

Zone One	$147.2m
Zone Two	$100.1m
Zone Three	$75.0m

[175] NTPG submission, 12 September 1999, p. 12.

A breakdown of the ORC valuations for each Zone can be found in Appendix B of this Draft Decision.

2.9 Tariff path and incentive structure

2.9.1 Code requirements

The Code (section 8.3) gives discretion to service providers as to how reference tariffs may be varied during an access arrangement period. For example, tariffs may change according to a 'price path' approach where tariffs follow a path determined at the start of the period. The alternative method specified in the Code is the 'cost of service' approach. Under this approach, tariffs are set according to forecast costs and are adjusted throughout the access arrangement period in light of actual outcomes. The Code also allows variations or combinations of the approaches to be used.

Section 8.44 of the Code provides for the regulator to require or approve an incentive mechanism. Such a mechanism enables a service provider to retain all or a share of any returns from the sale of a reference service that exceeds the level expected at the beginning of the access arrangement period. This mechanism operates particularly where the increased returns are attributable, at least in part, to the service provider's efforts. This incentive mechanism should encourage the service provider to increase sales volumes, minimise costs, develop new services, and undertake only prudent investment (section 8.46). The mechanism should be designed to ensure that users gain from any increased efficiency, innovation and improved sales volumes. The mechanism may include:

- specifying that tariffs are based on forecast, not realised, values of variables;
- setting a target revenue and specifying how revenue in excess of this is to be shared between the service provider and users; and
- establishing a rebate mechanism for rebatable services that does not provide a full rebate to users.

Sections 8.47 and 8.48 of the Code allow a reference tariff policy to include certain principles that remain fixed for a set period (referred to as the 'fixed period'). These fixed principles can not be changed without the agreement of the service provider and may only include structural elements and not 'market variable' elements.

While a fixed period may apply for all or part of the duration of an access arrangement, the regulator is required to consider the interests of users and prospective users in determining the period.

Section 10.8 of the Code defines a market variable element as:

> … a factor that has a value assumed in the calculation of a Reference Tariff, where the value of that factor will vary with changing market conditions during the Access Arrangement Period or in future Access Arrangement Periods, and includes the sales or forecast sales of Services, any index used to estimate the general price level, real interest rates, Non Capital Cost and any costs in the nature of capital costs.

2.9.2 NT Gas' proposal

As shown in Table 2.18, NT Gas proposed a set of 'smoothed' reference tariffs applicable to each pricing zone.

Table 2.18: Reference Tariffs ($/GJ) proposed by NT Gas

Year Ending 30 June	2000	2001	2002	2003	2004
Zone 1	1.49	1.46	1.42	1.39	1.35
Zone 2	1.11	1.08	1.06	1.03	1.01
Zone 3	1.03	1.00	0.98	0.95	0.93

Source: Access Arrangement Information, p. 32.
Note: In dollars of the day.

Reference Tariffs for each zone were determined by dividing the estimated throughput into the required revenue for that year. A smoothing parameter of X=-2.44 was applied to the Reference Tariffs calculated for 2000 to provide a smooth price path for Users over the access arrangement period, and to avoid price shocks at the commencement of the next access arrangement period. NT Gas used the following formula when applying the X factor to its tariffs:

$$t_n = t_{n-1}\,(1 + X)$$

NT Gas' access arrangement also provided for the calculation of reference tariffs if the revisions commencement date is later than 30 June 2004. The reference tariff would be adjusted on 1 July 2004 and then on each adjustment date thereafter using the following formula:

$$\text{Reference Tariff} = \text{Reference Tariff prior to Adjustment Date} \times \left[1 + \frac{\text{CPI}_n - \text{CPI}_{n-1}}{\text{CPI}_{n-1}}\right]$$

where 'adjustment date' means 1 January, 1 April, 1 July and 1 October.

Incentive Mechanism

NT Gas proposed that the following mechanisms would provide an incentive for NT Gas to reduce total operating costs and increase pipeline throughput:[176]

- The rebate mechanism under the Interruptible Service permits some of the revenue from the Rebatable Service to be retained by NT Gas.
- The Reference Tariff for the Reference Service will apply during each year of the access arrangement period, regardless of whether the forecasts on which the Reference Tariff was determined are realised.

[176] Access Arrangement, p.15.

Fixed principle

NT Gas proposed the following as a fixed principle:

> For the purposes of calculating the Capital Base at the commencement of the subsequent Access Arrangement Period, where the actual cost of New Facilities differs from the forecast New Facilities Investment on which the Capital Base was determined, the New Facilities Investment will be included at actual cost.[177]

2.9.3 Submissions from interested parties

NTPG submitted that the proposed incentive mechanism is 'perfunctory, and consistent with the NT Gas' strategy to discourage sales of the Reference Service.'[178] NTPG is of the view that rather than encouraging pipeline throughput, the zonal structure and level of the Reference Tariff will discourage throughput and create barriers to entry in the electricity industry. In support of this claim, NTPG compared PAWA's average shipment cost on the ABDP of $3.15 with the proposed $3.63 that would apply to an entrant in the Katherine-Darwin regional electricity market.[179]

Woodside proposed that average tariff revenue should be capped at CPI-X where X is an efficiency improvement factor of between 0.8 per cent and 1.5 per cent per annum over the access arrangement period.[180] Woodside stated:[181]

> We believe that such a mechanism will promote efficiency and help lead to lower delivered prices for customers. We would encourage ACCC to consider whether a higher efficiency improvement factor would provide a greater incentive for the onshore gas transmission pipeline or distribution network operator to reduce costs and increases volumes.

2.9.4 Commission Consideration

Tariff Path

Under the zonal tariffs proposed by NT Gas (Table 2.18 above), in the first year of the revised access arrangement period (that is the year ending 30 June 2002)[182] a customer situated in Zone Three would pay the sum of the throughput charges for each zone, or $3.46/GJ.

In section 2.2.7 the Commission outlined its adjustment of NT Gas' initial capital base to be consistent with the proposed depreciation schedule. As a result of this adjustment revenue and tariffs are substantially reduced, limiting any price shocks in the initial and subsequent access arrangement periods. Based on its own calculations, the Commission proposes an alternative tariff path. This is set out in Table 2.19.

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177 Access Arrangement, p.16.

178 NTPG submission, 12 September 1999,p. 14.

179 NTPG submission, 12 September 1999, p. 13.

180 Woodside/Shell submission, 9 September 1999, p. 4.

181 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p. 4.

182 As discussed in section 2.2.8, the access arrangement period will be five years from the date of final approval, the Commission has therefore determined revenues for the five-year period commencing 1 July 2001.

Table 2.19: Reference Tariffs ($/GJ) calculated by the Commission

Year Ending 30 June	2002	2003	2004	2005	2006
Zone 1	0.82	0.82	0.81	0.81	0.81
Zone 2	0.57	0.57	0.57	0.57	0.56
Zone 3	0.51	0.51	0.50	0.50	0.50

Under the Commission's proposed tariff path, for the year ending 30 June 2002, a customer in Zone Three would pay $1.90/GJ, this represents a reduction of approximately 45 per cent when compared to NT Gas's proposal of $3.46/GJ. The proposed tariffs calculated by the Commission have been escalated using a CPI-X mechanism where X = 2.47 per cent. This approach is discussed below.

CPI-X adjustment

As discussed earlier, NT Gas has proposed a price path using a tariff escalator of X = -2.44. While it is possible that the X factor used may already incorporate forecast changes in CPI, NT Gas' approach does not appear to explicitly provide for the effect on tariffs due to actual changes in the CPI.

Due to the absence of CPI in its formula, NT Gas' approach to smoothing tariffs over the access arrangement period results in NT Gas bearing the risk that inflation may be higher than expected. If this were the case, NT Gas would be under compensated for its actual costs. The Commission preference, as outlined in previous decisions, is to adopt a CPI-X tariff adjustment mechanism. This removes any inflation risk to the service provider as tariffs are annually adjusted for actual changes in inflation. In calculating the tariff (t) for a particular year (year n) using a CPI-X adjustment, the Commission prefers the use of the following formula:

$$t_n = t_{n-1}\ (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X)$$

The Commission proposes that an amendment should be made to the access arrangement to adopt the CPI-X tariff adjustment mechanism. However, should NT Gas provide the Commission with further justification to support its approach, the Commission will review this position.

When NT Gas lodged its proposed access arrangement it was assumed that the access arrangement would commence on, or soon after, 1 July 1999 and that the revisions commencement date would be on, or soon after, 1 July 2004. Consistent with that expectation, NT Gas proposed reference tariffs for the years up to 30 June 2004 followed by CPI-X indexation thereafter until the revisions commencement date.

While the current approval process only covers reference tariffs for the initial access arrangement period, the Commission notes that, based on the underlying assumptions, the resulting tariff path over the life of the asset would be consistent with the reference tariff principles established in section 8 of the Code.

NT Gas applied its X factor of -2.44 uniformly across all three zones. However, the Commission's preferred approach is to determine a different X factor for each zone. The volume forecasts provided by NT Gas show that throughputs for each zone do not increase uniformly over the access arrangement period. As throughput volumes are a key determinant of the level of tariffs, using the same X factor for each zone may not always adequately reflect the differences in throughput growth across zones.

For example, suppose throughputs for zone A of pipeline XYZ are expected to increase steadily over the next five years, but, throughput in zone B is expected to decrease substantially over the same period.[183] Smoothed individually, zone A would be subject to a positive X factor (that is, decreasing tariffs over time), whilst zone B would be subject to a negative X factor (that is, increasing tariffs over time). Moreover, applying the same X factor in both zones would effectively result in zone A subsidising zone B (that is, both tariffs would increase over time).

Consistent with this approach the Commission calculated an X factor for each zone. The X factor for Zones One, Two and Three were established as 2.46, 2.48 and 2.46 per cent respectively. The three X factors calculated are almost identical, which is most likely due to the pipeline being fully contracted with throughputs remaining fairly constant during the access arrangement period. Given the similarity in X factors across the three zones the Commission is of the view that the additional complexity associated with implementing individual X factors is unnecessary, and would have limited impact on the final tariffs calculated. Therefore, while the approach outlined above reflects the Commission's preferred approach to smoothing zonal tariffs, in this case the Commission proposes that a single X factor of 2.47 per cent be applied when smoothing tariffs in each zone.

Proposed Amendment A2.8

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas must amend the reference tariff proposed in Section 3 of the access arrangement. The amendment must have the effect that:

- the initial tariff (in 2001/02) is derived from the cost of service revenue resulting form the amendments proposed by the Commission in this Draft Decision; and

- in each subsequent year, the reference tariffs will be calculated using the CPI-X tariff escalator:

$$t_n = t_{n-1}\,(1 + (CPI_n\text{-}CPI_{n-1})/CPI_{n-1}).(1 - X)$$

where X = 2.47 per cent.

Section 3 of the access arrangement must be amended to remove the reference to CPI adjustment of NT Gas' proposed reference tariff for the year to 30 June 2004. In the event that there is a gap between the reference tariff years specified in the access arrangement and the revisions commencement date, the interim reference tariff will be

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[183] As the majority of costs are allocated based on the proportion of ORC and pipeline length, the costs attributed to each zone will remain fairly constant over the five year period.

determined by adjusting the final year's reference tariff in accordance with the CPI-X methodology discussed in this amendment.

Incentive Mechanism

An incentive mechanism is an important component of an access arrangement and effective regulation. The Commission accepts that to the extent the reference tariff is able to encourage greater pipeline utilisation, the incentive mechanism proposed by NT Gas is consistent with the requirements of the Code.

In its access arrangement NT Gas states that revenue from interruptible services will be distributed in accordance with the requirements of the Amadeus Gas Trust.[184] The Commission acknowledges that section 2.25 of the Code provides for the recognition of pre-existing contractual obligations and does not intend to interfere with existing contractual rights. It is the Commissions view, however, that while the rebate mechanism cannot be modified, details of how interruptible revenues will be distributed should be included in the access arrangement. This will allow potential users to further understand their rights under the access arrangement.

Proposed Amendment A2.9

In order for NT Gas' access arrangement for the ABDP to be approved, the access arrangement must be amended to include details of how revenue from interruptible services will be distributed.

Fixed principle

NT Gas has proposed one Fixed Principle that requires new facilities investment be incorporated in the capital base at the commencement of the next access arrangement period at actual cost rather than forecast cost. The proposed fixed principle is duplicated in section 4.6 of the reference tariff policy and as such the Commission has previously analysed the provision in section 2.3.4 of this decision.

Previous decisions by state regulators have expressed considerable concern with proposed fixed principles that appear to unnecessarily limit the normal discretion provided to the regulator. These decisions have also argued that where a proposed fixed principle appears to reproduce the Code then the fixed principle is unnecessary and should not be accepted.[185]

Section 8.22 of the Code states that either the reference tariff policy should describe or the relevant regulator should determine whether (and how) the capital base at the commencement of the next access arrangement period should be adjusted if actual new facilities investment is different from forecast new facilities investment.

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184 Access Arrangement, p. 6.

185 SAIPAR, Draft Decision: South Australian distribution system, April 2000; IPART, Final Decision: Albury Gas Company, December 1999; ORG, Final Decision: Victorian distribution, October 1998.

In this instance, section 4.6 of the reference tariff policy (after implementation of the Commission's Proposed Amendment A2.2) satisfies section 8.22 of the Code. Therefore, the fixed principle simply repeats a fundamental concept already established by the Code, the reference tariff policy and the Commission's own approach to regulation. The Commission considers that, in the absence of further evidence or support for the clause from NT Gas, the inclusion of the fixed principle is unnecessary and repetitious.

Proposed Amendment A2.10

In order for NT Gas' access arrangement for the ABDP to be approved, the fixed principle (section 4.8) must be deleted.

2.10 Assessment of reference tariffs and reference tariff policy

2.10.1 Code requirements

Section 3.4 of the Code requires the regulator to be satisfied that the access arrangement and any reference tariff included in the access arrangement comply with the reference tariff principles described in section 8 of the Code.

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

The reference tariff policy and all reference tariffs should be designed to achieve the objectives set out in section 8.1. These cover efficient service delivery, replicating a competitive market outcome, safe and reliable pipeline operation, signals for investment, efficient tariff design and incentives for cost reduction and market growth.

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

Similarly, the relevant regulator is to be satisfied that the reference tariff and reference tariff policy is consistent with the criteria set out in section 8.2. These cover the revenue to be generated from the sales (or forecast sales) of all services, the portion of total revenue to be recovered from users of various services. The criteria require that appropriate incentive mechanisms be incorporated in the access arrangement and that any forecasts used in setting the reference tariff represent best estimates arrived at on a reasonable basis.

In assessing all of these matters, the Commission must take into account the matters set out in section 2.24 of the Code. Stated briefly, the matters set out in that section are: the service provider's legitimate business interests and investment in the pipeline; firm and binding contractual obligations; the safe and reliable operation of the pipeline; the economically efficient operation of the pipeline; the public interest; the interests of users and prospective users; and any other matter that the regulator considers relevant.

2.10.2 NT Gas' proposal

Section 4 of the access arrangement is the reference tariff policy for the ABDP. This outlines the basis on which tariffs have been structured and states that NT Gas may undertake new facilities investment that does not meet the requirements of section 8.16 of the Code. The reference tariff policy also sets out incentive mechanisms for NT Gas and a fixed principle.

Section 3 of the access arrangement specifies the reference tariffs for the ABDP. This is supported by the reference tariff policy itself in addition to other material provided to the Commission by NT Gas.

2.10.3 Submissions from interested parties

Submissions to the Commission included significant comment on NT Gas' compliance with sections 8.1 and 8.2 of the Code. In particular, these comments focused on the proposed incentive mechanism, zonal pricing and the level of the Reference Tariff. These concerns have been discussed in the relevant sections of this Draft Decision.

2.10.4 Commission considerations

The Commission considers that NT Gas has complied with section 3.5 of the Code in providing a reference tariff policy in the access arrangement. As noted above, each of the aspects of the reference tariff policy have been assessed in the relevant sections of this Draft Decision. The following discussion draws together the Commission's conclusions within the framework of sections 8.1 and 8.2 of the Code.

Section 8.1 Objectives

Recovery of efficient costs associated with the provision of the reference service (8.1(a))

NT Gas has proposed a cost of service approach under which the total revenue requirement equates to the cost of providing the reference service. Under this approach the regulator is obliged to approve reference tariffs which deliver a revenue stream sufficient to recover the efficient costs of providing reference services. The 'efficient costs' test refers to both non-capital costs (such as operating and maintenance costs) and capital expenditure. Only those costs incurred by a prudent service provider acting efficiently should be included.

The Commission considers that the cost of service proposed by NT Gas would provide NT Gas with a return that is in excess of the recovery of efficient costs associated with the reference service. In the Commission's view the WACC and associated parameters, the initial capital base and the depreciation schedule proposed by NT Gas are not consistent with the principle of recovering efficient costs. The Commission is not satisfied that a tariff based on revenues proposed by NT Gas would satisfy the objective in section 8.1(a).

In this Draft Decision the Commission has also assessed the future capital expenditure and non-capital costs proposed by NT Gas. On the basis of available information and a number of key performance indicators, the Commission considers the forecast capital expenditure and non-capital costs proposed by NT Gas to be reasonable. Forecast capital expenditure will also be assessed again at the end of the access arrangement period under section 8.16 of the Code.

It is unlikely that reference services will be sold in this access arrangement period. However, the reference tariff resulting from the parameters proposed in the Draft Decision would provide the service provider with the opportunity, if it were supplying the reference service, to earn a stream of revenue that would recover efficient costs associated with that service.

Replicating the outcome of a competitive market (8.1(b))

Setting the regulated return on CAPM benchmarks means the returns achieved are expected to be similar to those achieved by a firm facing similar commercial risks operating in a competitive environment. The return is based only on those assets necessary to deliver the services required. The tariff path derived from the amendments in this Draft Decision represent pricing that is reflective of efficient cost, which is also a feature of competitive markets.

The incentive structure implemented in association with the reference tariff allows the service provider to achieve a return in excess of a normal return from increased efficiencies and growth in sales, which can also occur in a competitive market. However, over time, as in a competitive market, it is expected that these efficiency savings will be passed onto customers.

Ensuring the safe and reliable operation of the pipeline (8.1(c))

The reference tariffs are based on cost forecasts as being necessary for the safe and reliable operation of the pipeline. Each review of the access arrangement provides an opportunity for NT Gas to increase its revenue if the safety and reliability of the pipeline demands it. NT Gas may also request a review of the access arrangement at any time during the regulatory period.

Not distorting investment decisions in pipeline transmission or in upstream or downstream industries (8.1(d))

The rate of return set by the regulator should be sufficient to cover the service provider's cost of capital. A rate of return that is lower than that required by investors will be insufficient to attract investment in the long run. On the other hand, a higher than required rate of return will enable the service provider to set higher tariffs, earn monopoly rents and will result in a misallocation of resources. The Commission considers that the rate of return determined in this Draft Decision will not distort investment decisions.

Inter-temporal investment distortions are minimised by the smoothed price path provided by the Commission's proposed CPI-X tariff adjustment mechanism, which produces stable prices over the access arrangement period. The shift from 'postage stamp' pricing to zonal tariffs also represents an improvement in the locational pricing signals sent to downstream investors.

In its access arrangement information, NT Gas stated that the revenue earned under existing transportation contracts is less that the total revenue NT Gas would be entitled to recover under the Code. In the Commission's view the ICB and rate of return used by NT Gas overstate the initial capital base, depreciation schedule and return on capital. If the ICB and rate of return methodologies are correctly applied in accordance with the principles outlined in this Draft Decision, the result is a lower reference tariff that, in the Commission's view, still meets the revenue requirement of an efficient pipeline operator.

These outcomes suggest that the amendments the Commission has proposed to NT Gas' reference tariff policy and reference tariff are consistent with the objective of not distorting investment decisions.

Efficiency in the level and structure of the reference tariff(s) (8.1(e))

The zonal tariff structure proposed by NT Gas creates three postage stamp tariffs in the place of the existing 'postage stamp' tariff, with gas transportation charges varying between each zone. The Commission is of the view that distance based tariffs are likely to provide better price signals to the market than 'postage stamp' or zonal tariffs. However, given that most customers are located at the end of the ABDP the Commission considers that any loss in efficiency due to a zonal tariff would be minimal.

The Commission's Draft Decision rejects NT Gas' proposed tariff and the use of a smoothing parameter of X=-2.44. When determining the tariff path for the access arrangement period, the Commission prefers the use of a CPI-X approach. This approach, unlike NT Gas' explicitly provides for the effect on tariffs due to actual changes in the CPI and removes the inflation risk inherent in NT Gas' approach.

Incentives to reduce costs and expand the market (8.1(f))

NT Gas has sufficient incentive to reduce costs and expand the market, as any benefits arising from reduced costs and/or higher than forecast volumes can be retained by NT Gas during the term of the access arrangement period.

In its access arrangement NT Gas stated that its rebatable service is designed to provide NT Gas with an incentive to promote the efficient use of pipeline capacity and to share gains with users from additional sales of services. However, it is currently unknown what portion (if any) of revenue from interruptible services is retained by NT Gas under the rebate mechanism. The Commission has therefore proposed an amendment that requires NT Gas to reveal in its access arrangement how it intends to distribute revenue from the sale of interruptible services.

Section 8.2 Factors

Section 8.2 of the Code lists five factors about which the Commission is to be satisfied in determining whether to approve the reference tariff. These are assessed below.

Total revenue is established consistently with the principles and according to one of the methodologies contained in section 8 of the Code (8.2(a))

NT Gas has determined its revenue requirement based on a cost of service approach with a smooth price path to avoid price shocks. This approach is consistent with the Code.

However, while NT Gas has utilised the cost of service approach in determining its reference tariff, it is the Commission's view that NT Gas' proposed capital base, rate of return and depreciation allowances are overstated. As a result of the amendments proposed in this Draft Decision, NT Gas' revenue stream would be less that that proposed by NT Gas.

The proportion of total revenue that any one reference tariff is designed to recover is calculated consistent with the principles of section 8 of the Code (8.2(b))

Sections 8.38 to 8.41 of the Code provide guidance favouring cost-reflective pricing, to the maximum extent that is commercially and technically reasonable. These provisions are subject to considerations of providing incentives for market growth and avoiding loss of supply opportunities.

NT Gas' access arrangement includes a single reference service (transportation service). Accordingly, for tariff setting purposes NT Gas has allocated all costs to this service and assumed all volumes relate to this service. While this approach may at first seem inconsistent with the Code, little revenue is expected from other services and a more precise methodology of allocating total revenue is not considered necessary at this point in time.

The proportion of total revenue recovered from users of a service is calculated consistent with the principles of section 8 of the Code (8.2(c))

NT Gas has determined only one reference tariff (comprising of three zonal tariffs) for its reference service. The Commission has assessed the information used by NT Gas to determine and allocate costs for each zone and is satisfied with the methodology used.

The Commission considers that, after implementation of the proposed amendments, the tariffs would recover from each user a fair and reasonable share of costs.

Incentive mechanisms that are incorporated are consistent with the principles of section 8 of the Code (8.2(d))

In addition to the ability to retain additional revenue from an increase in volumes, NT Gas' proposed an incentive mechanism that permits some of the revenue from the rebatable service to be retained by NT Gas. The Commission accepts that to the extent the reference tariff is able to encourage greater pipeline utilisation, the incentive mechanism proposed by NT Gas is consistent with the requirements of the Code. However, as noted above, the Commission has proposed an amendment to the access arrangement to include details of exactly how revenue from interruptible services will be distributed.

Forecasts used are best estimates determined on a reasonable basis (8.2(e))

The Commission considers the forecast costs are reasonable. The forecast volumes provided by NT Gas are essentially equivalent to the existing capacity of the pipeline and are therefore considered acceptable.

3. Non-tariff elements

In this chapter the mandatory non-tariff elements of the proposed access arrangement for the ABDP are assessed for compliance with the Code. The Code requirements are outlined for each mandatory element followed by a summary of the service provider's proposal, the issues raised in submissions, and the Commission considerations. Where relevant these are followed by amendments that the Commission proposes to be made for the access arrangement to be approved. All amendments are replicated in the executive summary.

3.1 Code Requirements

Section 3 of the Code establishes the minimum content of an access arrangement, which includes the following non-tariff mandatory elements:

- a services policy that must contain at least one service that is likely to be sought by a significant part of the market;
- terms and conditions on which the service provider will supply each reference service;
- a capacity management policy to state whether the covered pipeline is a contract carriage or market carriage pipeline;
- in the case of a contract carriage pipeline, a trading policy which refers to the trading of capacity;
- a queuing policy which defines the priority that users and prospective users have to negotiate capacity where there is insufficient capacity on the pipeline;
- an extensions/expansions policy which determines whether an extension or expansion of a covered pipeline is or is not to be treated as part of the covered pipeline for the purposes of the Code; and
- a review date by which revisions to the access arrangement must be submitted and a date on which the revisions are intended to commence.

An access arrangement must also contain a reference tariff policy and at least one reference tariff. These provisions were assessed for compliance with the Code in chapter 2.

3.2 Services Policy

3.2.1 Code requirements

Sections 3.1 and 3.2 of the Code require an access arrangement to include a services policy which must include a description of one or more services that the service provider will make available to users and prospective users. The policy must describe any services likely to be sought by a significant part of the market, and that in the relevant regulator's opinion should be included in the services policy.

When practicable and reasonable, a service provider should make available those elements of a service required by users and prospective users and, if requested, apply a separate tariff to each element.

3.2.2 NT Gas' Proposal

NT Gas' proposed services policy consisted of three services – a Transportation Service, an Interruptible Service and a Negotiated Service.

NT Gas has described the three services in the following manner:

> **Transportation Service** — Reference Service for transport from the Receipt Points to any Delivery Points on the Pipeline with tariffs charged on the basis of throughput ($ per GJ of throughput).
>
> **Interruptible Service** – Rebatable Service (non-Reference Service) for transport from the Receipt Points to any Delivery Points on the Pipeline with tariffs charged on the basis of throughput ($ per GJ of throughput), where NT Gas is entitled to cease receiving gas from, or delivering gas to, the User when pipeline capacity is constrained/curtailed or to meet the capacity requirements of other Users.
>
> **Negotiated Services** — agreements negotiated to meet the needs of a User which differ from those in the Transportation Service or the Interruptible Service.

Transportation service

NT Gas stated in its access arrangement that there is currently no firm capacity available in the pipeline, with all capacity utilised under pre-existing Service Agreements for forward haul in the nature of the Transportation Service. Given that forward haul is the service most likely to be sought by the market, NT Gas has defined the Transportation Service in this access arrangement to enable prospective users to understand the conditions on which the service would be offered if capacity becomes available.

Key factors relating to the proposed transportation service include:[186]

- users are required to establish a level of MHQ which fairly reflects their maximum hourly requirement at each delivery point, and a yearly level of an ACQ and MDQ to reflect their needs under the transportation service;
- NT Gas' maximum obligation to deliver gas is MHQ in any hour, MDQ on any day and ACQ over a contract year;
- an overrun will occur when withdrawals by the user at a delivery point exceed the MHQ in any hour or the MDQ on any day. Overruns may be authorised or unauthorised; and

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[186] NT Gas Access Arrangement, 25 June 1999, Section 1, p.4.

- the term of the transportation service will be one year or longer if the user so elects.

Interruptible service

The Interruptible Service is also offered to enable prospective users to understand the conditions on which capacity may be available at this time. NT Gas does not believe this service will be sought by a significant part of the market. The interruptible service will be available on a day if all the pipeline system capacity is not required to provide transportation service to other users.

Key factors relating to the proposed interruptible service include:[187]

- users are required to establish a level of MHQ which fairly reflects their maximum hourly requirement at each delivery point, and a yearly level of an ACQ and MDQ to reflect their needs under the interruptible service;
- where NT Gas reasonably believes the MDQ established by the user does not fairly reflect the user's needs, NT Gas may revise the MDQ to fairly reflect the User's needs;
- NT Gas' maximum obligation to deliver gas is MHQ in any hour, MDQ on any day and ACQ over a contract year; and
- an overrun will have occurred if withdrawals by the user at the delivery point exceed the MHQ in any hour, or the MDQ on any day. Overruns may be authorised or unauthorised.
- services to users will be curtailed or interrupted prior to services to other users where necessary for operational purposes or in response to emergencies or events of force majeure, or to ensure NT Gas is able to comply with any pre-existing service agreement; and
- the term of the interruptible service will be one month or longer if the user elects so, but not extending beyond the revisions commencement date.

The general terms and conditions in schedule 2 apply to both interruptible and transportation services.

Negotiated Service

Where a prospective user has specific needs and would neither be satisfied with the reference (transportation) or the interruptible service, the user might seek to negotiate different terms and conditions as a Negotiated Service.[188]

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[187] NT Gas Access Arrangement, 25 June 1999, Section 1.2, p.5.

[188] NT Gas Access Arrangement, 25 June 1999, Section 1.3, p.7.

Access and Requests for Services

Conditions, which a prospective user must observe before gaining access to the service, were set out in section 1.4 and summarised as follows:[189]

- a prospective user must lodge a request and meet NT Gas' prudential requirements;
- a prospective user may have only one active request for the same tranche of capacity to a particular delivery point;
- NT Gas within 30 days of receiving a complete request advice whether capacity is available and at what price;
- a request will lapse unless, within 30 days of NT Gas advising that capacity is available, the prospective user has either entered into a service agreement or commenced negotiations;
- whether there is sufficient capacity to meet a request, there will be no queue; and
- where there is insufficient capacity to satisfy a request, then a queue will be formed and the queuing policy will apply.

Distinction between 'prospective user' and 'user'

In section 1.4 the term 'prospective user' and 'user' are separately defined. A 'prospective user' does not include a 'user', who is exercising its rights under a Service Agreement, which existed as at 25 June 1999. In most respects the access arrangement applies only to users, those who would be supplied with the specified transportation or interruptible services. The arrangement applies to prospective users where they are specifically mentioned, for instance, in determining order of priority of service relative to users.

3.2.3 Submissions by interested parties

In their submissions parties raised the following issues in respect of NT Gas' proposed services policy:

- ABDP system capacity constraint; and
- the lack of provision in the access arrangement for a back haul tariff.

System capacity constraint

NTPG has disputed the claim by NT Gas that capacity limitations are a constraint on sale of the reference service or negotiated service within the access arrangement. NTPG submitted, 'that provided an adequately sized second compressor is funded by PAWA under existing lease obligations, ABDP system capacity constraints will not prevent sale of the Reference Service over the access arrangement period'.[190]

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[189] NT Gas Access Arrangement, 25 June 1999, Section 1.4, p. 8.

[190] NTPG submission, 12 September 1999, p. 6.

PAWA responded to NTPG's comments in relation to PAWA's obligation to fund a second compressor pursuant to its agreement with NT Gas. PAWA rejected that it had an immediate obligation to fund another compressor.[191] In addition, NT Gas stated:

> Where a party (including PAWA) has capacity requirements, which require an additional compressor, that party will be responsible for funding the installation of the compressor. In respect of any obligation, which may exist under the Gas Sales Agreement for PAWA to fund another compressor, this is a confidential contractual matter between NT Gas and PAWA and is not an appropriate matter for third parties to seek to enforce through the access arrangement.[192]

Back haul tariffs

Santos and Woodside have both commented on the lack of provision for back haul in the access arrangement. Santos argued that an offshore NT Gas development such as the Petrel-Tern Project would require a back haul of gas. Santos and Nabalco noted that the proposed access arrangement does not account for the potential gas transportation issue associated with an offshore NT Gas development such as the Petrel-Tern Project. Santos is concerned that the Petrel-Tern project would require them to negotiate for back haul tariffs. If a commercial tariff could not be agreed upon, this could potentially cause the project to remain undeveloped.[193]

Santos considered that it would potentially require access to the ABDP for back haul services sometime between 2002 and 2005, that is within this access arrangement period.[194] Woodside stated that it is planning together with Shell the development of its Timor Sea gas resources. This project does require the provision of a back haul tariff but does not require access to the ABDP during this regulatory period, beyond 2005.[195] Nabalco raised the possibility that gas brought onshore from Timor Sea could be available in Darwin as early as late 2003. [196]

3.2.4 Relevance of existing haulage agreements to range of services offered to third parties.

Outline of existing haulage agreements

The main existing haulage agreement is between NT Gas and PAWA, which is due to extend until 2011.

The ABDP was constructed with the support of PAWA's predecessor (the Northern Territory Electricity Commission) and the Territory. PAWA was the foundation customer for the Pipeline and is still the major user of the pipeline.

In the Territory the only economically viable fuel for electricity generation has been gas. Since the early 1980's, the Territory's planning for electricity supply has

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191 PAWA submission, 17 November 1999, p. 3.

192 Email from Agility Management, on behalf of NT Gas, to Commission staff, 27 March 2001.

193 Santos submission, 8 September 1999, p.4.

194 Santos submission, 8 September 1999, p. 3.

195 Woodside submission, 9 September 1999, p. 1.

196 Nabalco submission, 9 September 1999, p. 2.

encompassed the development of indigenous gas as the primary fuel. All major decisions by PAWA in relation to the implementation of this policy are subject to Ministerial or Cabinet endorsement.[197]

Impact on access

According to NT Gas, there is currently no firm capacity available in the pipeline, with all capacity utilised under pre-existing service agreements for the transportation service.

The fully-contracted state of the pipeline system, together with a number of features of the current haulage arrangements, means that transportation services are unavailable to third parties unless the pipeline system is expanded or extended or the party negotiates with existing users for access to capacity they have reserved.

In relation to the potential for interruptible service, there is in the vicinity of 5TJ/d of capacity available on an interruptible basis. The availability of such capacity depends on seasonal factors reflecting that gas is transported through the ABDP is primarily used for power generation. PAWA has indicated that there is likely to be some interruptible capacity available. However, PAWA has noted that it is unlikely that the capacity will be available when required by any other generator of electricity.[198]

In addition to the users rights to use the pipeline's total capacity, the current users with existing contractual rights in force as at 25 June 1999 have the right to increase capacity reservation over any request from a user that has not yet entered into a service agreement.[199]

Section 3.6.4 of the Draft Decision discusses the impact that the existing users pre-emptive rights to capacity have on the queuing policy.

Code provisions

The main objective of the Code is to ensure that users and prospective users are able to gain access, on reasonable terms, to services utilising spare capacity in the pipeline system. The notion of spare capacity includes not only uncontracted capacity but also contracted but unused capacity. (See in particular the definition of 'Spare Capacity' in section 10.8 of the Code, and sections 3.2, 3.6, 3.12, 5.4, 5.9 and 6 and the overview of section 6 of the Code.)

The notion of access to reserved but unused capacity does not confer any power on the regulator or arbitrator to interfere with the rights of existing users under contracts already in place. However, there is an exception to the requirement to give effect to existing firm and binding contractual obligations. Sections 2.25, 2.47 and 6.18 of the Code all state that the regulator or the arbitrator must not make a decision that has the

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[197] PAWA submission, 17 November 1999, p. 1.

[198] PAWA submission, 17 November 1999, p.3.

[199] NT Gas Access Arrangement, 25 June 1999, Section 6.4, p. 19.

effect of depriving a person of an existing contractual right, ‘other than an Exclusivity Right which arose on or after 30 March 1995’.

3.2.5 Commission’s considerations

In the Draft Decision the Commission’s consideration of the proposed access arrangement has been influenced by the existing haulage agreements to which NT Gas is a party. NT Gas has argued that given its existing capacity is fully committed it has limited scope to offer the reference service during the first access arrangement without enhancement of the pipeline system.

As mentioned, NTPG claimed that PAWA has an immediate obligation to fund a second compressor pursuant to its agreement with NT Gas. The Commission in reviewing the agreement between NT Gas and PAWA could not find any conclusive evidence that supported the claim that PAWA has an immediate obligation to fund a second compressor.

Reference Transportation Service

The Commission considers that the transportation service proposed by NT Gas meets the requirements of users and potential users in terms of section 3.2 of the Code.

In reaching this decision, the Commission has been guided by the code, which requires the Commission to have regard to the constraints arising from the existing haulage contracts other than exclusivity rights arising on or after March 1995. This approval of the proposed reference service is qualified by the modifications of the reference tariff provisions, access policies and terms and conditions of service required by the Commission in amendments proposed elsewhere in this Draft Decision.

Section 3.2.6 of the draft decision discusses back haul tariffs.

Rebatable Interruptible Service

The Commission accepts that the revenues likely to be derived from interruptible service are unpredictable and that it is appropriate to propose the interruptible service as a rebatable service. The Commission acknowledges that provisions of the existing haulage agreements prevent NT Gas from specifying in its access arrangement the exact quantity of gas that will be available for the interruptible service.

Negotiated Service

A negotiated service is a common element in recent access arrangements and proposed access arrangements. They enable service providers to accommodate any special requirements of a user or a potential user, presumably at additional cost to the user over the regulated services offered.

Access and Requests for Services

The Commission considers that NT Gas provides a reasonable time to complete a request. Given that there is insufficient capacity to satisfy a request for a prospective user, the Commission considers that the queuing policy and extensions and expansions policy becomes a significant factor for the prospective user in gaining access to capacity.

The Commission notes that the provision for access and requests for services and queuing policy requires users and prospective users to meet NT Gas' prudential requirements prior to the user requesting a service or assigning a request on a queue.[200] For reasons set out in section 3.3.4 of the Draft Decision, the Commission considers that it is important for users and prospective users to be aware of the specific prudential requirements when using the ABDP.

3.2.6 Requests for a back haul reference service

In the event of gas being brought onshore from the Timor Sea to Darwin, the ABDP will be able to offer a back haul service given the alternative source of gas supply now available. The Commission can require the inclusion of a tariff for back haul services if the Commission is of the view that section 3.3 of the code is satisfied.

Section 3.2 of the Code specifies the principles according to which services must be described in the access arrangement. Section 3.2(a)(ii) allows the Commission to require the service provider to include a service description for any service that it considers 'should be included in the Services Policy', whether or not it is likely to be sought by a significant part of the market.

Section 2.24 of the Code provides, relevantly, that:

> The Relevant Regulator may approve a proposed Access Arrangement only if its is satisfied that the proposed Access Arrangement contains the elements and satisfies the principles set out in section 3.1 to 3.20. The Relevant Regulator must not refuse to approve an Access Arrangement solely for the reason that the proposed Access Arrangement does not address a matter that sections 3.1 to 3.20 do not require an Access Arrangement to address.

In the light of section 2.24 of the Code, the intention of section 3.3 is that, while the service provider must include a tariff for at least one service that is likely to be sought by a significant part of the market, and may include a tariff for more than one service, the Code does not require it to include a Reference Tariff for any service that is not 'likely to be sought by a significant part of the market'.

Does a back haul service satisfy the test in section 3.3?

In analysing whether or not a service is 'likely to be sought by a significant part of the market', it is worth testing the notion of 'likely' and 'significant' in regard to the particular service.

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200 NT Gas Access Arrangement, 25 June 1999, p. 8. and p. 18.

Likely

The notion of 'likely' means at its lowest that there is a 'real chance or possibility' that something will occur,[201] and at its highest that is 'more probable than not' that an event will occur.[202]

When looking at the notion of 'likely' there are two main issues that must be tested:

- the likelihood of any parties seeking a back haul tariff in the event that Timor Sea gas comes onshore to Darwin; and
- the likelihood that Timor Sea gas will come onshore to Darwin.

In regard to any parties seeking a back haul tariff, the Commission notes that three independent entities, Woodside, Santos and Nabalco have made submissions indicating an intention of seeking a back haul tariff. These submissions are strong evidence of a likelihood that at least one of these entities will seek the service in the event that Timor Sea gas comes onshore to Darwin.

In regard to gas coming onshore from the Timor Sea, the Commission notes that a number of plans for developing gas reserves have been articulated, however, at this stage it is inconclusive whether or not these plans will reach fruition.

The Timor Sea is regarded as one of the most accessible prospective regions in the world for oil and gas. Timor Sea could find its way into new markets in the NT, Queensland and the South-Eastern States.[203]

There are a number of significant investment projects that are currently being conducted in the Timor Sea.

Potential Projects

The Northern Australia Gas Venture (Greater Sunrise and Evans Shoal Gas fields)

The Gas fields lie in the Bonaparte Basin, about 400km northwest of Darwin and proven probable reserves are estimated to be about 15.5 trillion cubic feet (tcf) of gas and 160 billion barrels of condensate. Shell and Woodside each hold 50 percent interest in the joint venture, while Woodside is the operator. Shell/Woodside anticipate that the potential exists for LNG sales from Darwin (around 2005) with the potential major customers being Japan, Korea, China and Taiwan.[204]

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201 See Deane J in *Tillmanns Butcheries Pty Ltd v The Australian Meat Industries Employees Union* (1979) ATPR 40-138 at p. 18,5000.

202 See Bowen CJ in the *Tillmanns Butcheries case.*

203 Australia Investment Opportunities in the Northern Territory, Database publishing company, http://www.tradeport.org/ts/countires/australia/ mrr/mark0037.html.

204 Australia Investment Opportunities in the Northern Territory, Database publishing company, http://www.tradeport.org/ts/countires/australia/ mrr/mark0037.html.

Laminaria/Corallina

The Gas fields have proven and probable oil reserves of around 200 million barrels. Woodside as the operator started production in early February 2000. The joint partners, Woodside, Shell and BHP have already signed agreements with eight existing Japanese LNG Customers for the next twenty years.[205]

The Bayu-Undan Field

The Gas fields are located approximately 500km north of Darwin. The Bayu-Undan field is estimated to contain 400 million barrels of condensate and LPG and 3.4 tcf of natural gas. Phillips the operator can process liquids offshore and pump the gas back into the reservoir or it can produce oil and gas (the gas will be exported to Darwin).[206]

Epic Energy – Darwin to Moomba Pipeline

Epic Energy is proposing to construct a new pipeline from Darwin to Moomba to bring gas from the Timor Sea to the gas markets of Southern and Eastern Australia. Epic has an alliance with Phillips Petroleum, the operator and majority unit holder of the Bayu-Undan gas field. Epic's proposed Darwin to Moomba pipeline (DMP) was granted Major Project Facilitation Status by the Commonwealth Government in November 2000.

Epic has indicated that it proposes to submit an access undertaking under Part IIIA of the Act in respect of the proposed pipeline.

In view of these proposals the Commission considers that there is some probability that Timor Sea gas will come onshore, however, the Commission at this stage considers it difficult to estimate what that probability is.

Significant

The notion of 'significant' is less onerous than 'substantial', and may mean no more than that the part of the market seeking the service must not be 'insignificant'. In determining whether a 'significant' part of the market is likely to seek the service it would be inappropriate to have regard only to numbers or percentages. In the case of one person seeking a service, the Commission would be inclined to look at whether that person is (or could be) a significant player in the market.

In regard to the parties that requested a back haul service in the event of gas coming onshore from the Timor Sea, the Commission considers that they make up a 'significant' part of the market. The three parties include:

- Woodside, a major participant in the Northern Australia Gas Venture (Greater Sunrise and Evans Shoal Gas fields) and the Laminaria/Corallina project;

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205 Australia Investment Opportunities in the Northern Territory, Database publishing company, http://www.tradeport.org/ts/countires/australia/ mrr/mark0037.html.

206 Australia Investment Opportunities in the Northern Territory, Database publishing company, http://www.tradeport.org/ts/countires/australia/ mrr/mark0037.html.

- Santos, an operator of the Petrel and Tern offshore gas fields; and
- Nabalco, manages the Gove Joint Venture bauxite mine and alumina refinery situated in Arnhem land.

In the event of gas being brought onshore to Darwin, there will be an alternative gas source for customers other then the Amadeus Basin. An indication or the demand for back haul services is reflected by the average daily and peak demands of gas for customers along the ABDP, other then Darwin customers. The access arrangement information provides a table of the load profiles in 1998[207]. It appears that 5154.6 TJ/Annual (which is 32 percent of the total annual volume) of the ABDP gas was demanded from customers other Darwin customers.

The Commission considers that in the event that Timor Sea gas is brought onshore to Darwin, a 'significant' part of the market would demand a back haul service.

Back haul services – Options available

Given the potential for Timor Sea gas to come onshore, the Commission has under the Code a number of options available to it. The Commission could require the inclusion in the access arrangement of:

- a service description and a Reference Tariff for the back haul service, see section 3.3(b) of the Code. A Reference Tariff Policy would also be required, as would terms and conditions;
- a trigger mechanism for an early review of the access arrangement, see section 3.17(b)(ii) of the Code. As part of the review the Commission could require NT Gas to include a service description and tariffs for a back haul service in the event that it became clear that it was sought by a significant part of the market; or
- a statement of principles to apply to the calculation of tariffs for back haul services, see section 3.5 of the Code,[208] in the event of gas coming onshore from the Timor Sea.

If the later option were adopted, then the principles would become binding on the arbitrator, in the sense that he/she must not make a determination that conflicts with those principles see section 6.18(a) of the Code. This could be useful in providing a framework for negotiations. In assessing the principles, the Commission would be required to have regard to the criteria set out in section 2.24. The Commission would not be required to assess them against the Reference Tariff Principles of section 8 of the Code, however, it could have regard to these principles if it considered that they were relevant to section 2.24 of the Code.

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[207] NT Gas Access Arrangement Information, 25 June 1999, Section 5.3, p. 39

[208] Section 3.5 of the Code requires the service provider to include a 'policy describing the principles that are going to be used to determine a Reference Tariff (a Reference Tariff Policy). The application of this provision implies that the policy will be used in the future (ie after the approval of the access arrangement) for determining a Reference Tariff. A "Reference Tariff", on the other hand, in the Code means a tariff that is already specified in the access arrangement (see definitions of Reference Service and Reference Tariff in Section 10.8 of the Code.)

Conclusion

The Commission at this stage cannot conclusive state whether or not back haul services satisfy section 3.3 of the Code. However, the Commission has given consideration to requiring NT Gas to incorporate in the access arrangement, pursuant to section 8.17(ii) of the Code, a trigger for early review in the event that a 'significant event' occurs. This would give other interested parties the opportunity to make submissions for changes to the access arrangement, but only if that trigger were activated. An example of such a trigger might be the event that Timor Sea gas comes onshore to Darwin.

The Commission will be assisted in reaching a final position by submission on the matter from the applicant, users and prospective users. The submissions should address the following issues:

- whether it is likely that Timor Sea gas will come onshore;
- whether to include a section 3.17 trigger in the access arrangement;
- if so, how to define a 'significant major event' for purposes of that trigger; and
- whether the regulator's scope for review of the access arrangement should be limited, for example reviews of the tariff structure only.

In the event the Commission is persuaded by submissions that the access arrangement should incorporate a trigger event it would, as part of the further process of public consultation:

- make the terms of such events known to NT Gas prior to the final decision; and
- make known its views as to the scope of any review that should be triggered by the occurrence of the specific major event.

Proposed Amendment A3.1

For the access arrangement to be approved, the Commission requires that NT Gas amend the access arrangement by defining, in response to the further process of public consultation, specific major events (if any) that would trigger an obligation on the service provider to submit revisions prior to the revisions submission date.

3.3 Terms and Conditions

3.3.1 Code requirements

Section 3.6 of the Code requires an access arrangement to include the terms and conditions on which a service provider will supply each reference service. These terms and conditions must be reasonable according to the relevant regulator's assessment.

3.3.2 NT Gas' proposal

NT Gas stated that it will provide the reference service on the terms and conditions set out in its standard service agreement for the reference service from time to time. The key terms and conditions are set out in Schedule 2 of the access arrangement.

Schedule 2 is divided into three parts:

1. general – topics include: relationship between NT Gas and user; obligation to transport: gas pressure; nominations; MHQ, MDQ and ACQ; daily variance; system use gas linepack; metering; allocation; accounts and payments; force majeure; liabilities and indemnities; interruptions and curtailments; option to extend; title to and responsibility for gas; metering and records; gas quality; part periods; and overruns;

2. calculation of imbalance; and

3. connection of metering facilities to the pipeline.

NT Gas stated that it will not discriminate between prospective users in the provision of services on the basis of:

(a) past transactions or relationships with NT Gas;

(b) the identity of the prospective user;

(c) the fact that the prospective user is a related part of NT Gas; or

(d) the source of the gas proposed to be transported, subject only to the gas meeting the specifications.

Nominations

NT Gas stated that the user must provide a nomination for each month at least 7 days prior to the first day and may vary the nomination (up to MDQ) in respect of any particular day by giving reasonable notice (but no later than 3 pm on the business day prior to that day). In addition, NT Gas stated that if it agrees to a request for an authorised overrun for a user, the user's nomination for that day will be deemed to be revised to reflect the authorised overrun quantity.[209]

MHQ, MDQ and ACQ

The user must establish for each contract year an MHQ, an MDQ and an ACQ that is to apply for the whole of that contract year. The MHQ will be no greater than 1.2 x (MDQ/24) unless agreed otherwise.

NT Gas submitted that where gas is to be delivered into more than one pipeline at more than one delivery/receipt point, the user must establish an MHQ and a delivery/receipt point MDQ.

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[209] NT Gas Access Arrangement, 25 June 1999, Schedule 2, p. 26.

NT Gas submitted that except as an authorised overrun and subject to the limitation on its obligation to receive or deliver gas up to the user's MDQ, NT Gas will not be obliged on any day:

- to deliver at any of the user's delivery points a quantity of gas greater than the delivery point MDQ for that delivery point; and
- to receive at any of the user's receipt points a quantity of gas, excluding system use gas and the user's share of user' linepack, greater than the receipt point MDQ for that receipt point.

In addition, NT Gas stated that it will not be obliged in any hour to deliver at any delivery point a quantity of gas greater than the MHQ for that delivery point.[210]

System Use Gas and Linepack

The system use gas and linepack service proposed by NT Gas can be summarised as follows:

- the user will supply at its cost the proportion of users' linepack determined by NT Gas which will not exceed the quantity determined by multiplying:
  - the ratio of the user's MDQ to the total MDQ of all users at that time; by
  - the amount determined by NT Gas as users' linepack at that time;
- if the quantity of gas supplied by a user as linepack at any time is less than 90 percent of its proportion of users' linepack, NT Gas may require the user to correct the shortfall as soon as possible. If the user fails to correct the shortfall within 4 hours of receipt of the notice, NT Gas may without liability or notice to the user reduce the quantities of gas delivered to the user.

Interruptions and Curtailments

NT Gas submitted that if it proposed to carry out any planned work which may affect its ability to provide services to users, NT Gas will give users reasonable notice of the planned work.   In addition NT Gas stated that when necessary:

- to protect the operational integrity and/or safe operation of the pipeline;
- to comply with any applicable laws and regulations;
- during an emergency situation; or/and
- the immediate repairs or maintenance required;

and after giving as much notice to the users as is reasonably practicable, NT Gas will be entitled without liability to curtail or interrupt receipts or deliveries of gas.

[210] NT Gas Access Arrangement, 25 June 1999, Schedule 2, p. 27.

NT Gas submitted that where services are to be curtailed or interrupted due to the preceding events:

- services to users of the interruptible service will be curtailed or interrupted prior to curtailment or interruption of other users;
- those services will be curtailed or interrupted downstream to the location of the affected part of the pipeline; and
- as between users whose services have the same priority, those users will be curtailed or interrupted proportionately according to the user's nominations for the first day and MDQ thereafter, or as otherwise agreed with all users.[211]

Liabilities and Indemnities

NT Gas stated that each party will be responsible and liable for the maintenance and operation of its properties and facilities under a service agreement and indemnifies the others for any claim or action respect of or arising out of them. NT Gas proposed that each party indemnifies the other in respect of any inaccuracy of representation, warranty or covenant made by it or failure to perform or satisfy any of the provisions of the service agreement.

Liability will be limited to actual damages except for:

- delivery of non-specification gas to a receipt point;
- delivery of non-specification gas to a delivery point due to the negligence or wilful default of NT Gas;
- failure by the user to cease delivery or taking of gas as required under the service agreement; or
- withdrawal at a delivery point of a quantity greater then MHQ in any hour or a quantity greater than MDQ in any day except as an authorised overrun.[212]

Allocation

NT Gas proposed that where gas is delivered to more than one user at a delivery point and/or at a receipt point:

- and those users cannot establish an appropriate allocation methodology acceptable to NT Gas and cannot provide sufficient information to NT Gas to enable it to reconcile between users quantities of gas received and delivered, then NT Gas will be entitled to adopt a reasonable methodology such as a pro-rating based on nominations.[213]

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211 NT Gas Access Arrangement, 25 June 1999, Schedule 2, p. 30.

212 NT Gas Access Arrangement, 25 June 1999, Schedule 2, p. 29.

213 NT Gas Access Arrangement, 25 June 1999, Schedule 2, p. 28.

Gas quality specifications

NT Gas' gas quality specification for the ABDP are set out in Schedule 3 of the access arrangement. The specifications include heating value, Wobbe Index, sulphur content and receipt point temperature and reflect the specifications for the MSP.

Section 5 of the access arrangement information provides details relating to the technical specifications of the pipeline.

NT Gas has nominated the pressure at which gas will be delivered to users as between 9,400 kPa and 10,000 kPa. This range of acceptable pressures is based on the pressures used in the MSP.[214]

Overruns, variances and imbalances

NT Gas stated that overruns are a method used by a pipeliner to ensure that on any day the pipeline can deliver users their MDQ. Overruns occur when either MHQ or MDQ is exceeded. That is, when gas delivered is greater than that nominated by the user. An overrun can be authorised (where NT Gas has agreed to a user's request for additional gas at a particular delivery point) or unauthorised.

Users of the ABDP face an overrun charge when the contracted capacity of the ABDP is at least 85 percent of the pipeline capacity. NT Gas purposed an authorised overrun charge of 20 percent of the reference tariff. The unauthorised overrun charge is to be 100 percent of the reference tariff.[215]

In the event that the ABDP contracted capacity is greater than 85 percent of the pipeline capacity NT Gas will limit the availability of authorised overruns to users. A user will not be entitled to an authorised overrun if that user has already exceeded MDQ for four days of the month or 105 percent of MDQ on more than 12 days in the year.

NT Gas stated that it will allow daily variances (where the delivered or received quantity exceeds the nominated amount by more then ten per cent) to occur on four days within a month (or 24 days in a year) before a user is required to pay a daily variance charge. By charging an additional 120 percent of the reference tariff for the daily variance quantity, NT Gas claimed that users are provided with an incentive to correctly nominate their gas needs.

NT Gas acknowledged that it is impossible for a user to balance receipts and deliveries on any one day and, consequently, has established an inventory system. A user's imbalance is calculated each month.[216] If an imbalance exists a user is expected to

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[214] NT Gas Access Arrangement, 25 June 1999, Schedule 3 and NT Gas, Additional General Information, p. 37.

[215] These overrun charges differ from those in the access arrangement.

[216] Imbalance = input – withdrawal – change in user's linepack. Access arrangement, Schedule 2, Part 3.

rectify it during the next month. If at the end of three months a user remains out of balance then the quantity attracts an imbalance charge.[217]

3.3.3 Submissions by interested parties

Santos submitted that existing and potential gas users and gas suppliers should be consulted regarding the appropriate gas specification for the ABDP system. Santos stated that such an approach is preferred rather than the imposition of a standard, which may result in additional upstream costs to meet a rigid specification, which is not necessary for the NT's dominant industrial user base.[218]

3.3.4 Commission considerations

The only response from interested parties to the proposed terms and conditions was Santos requesting that NT Gas consult users regarding the appropriate gas specification for the ABDP system. The Draft Decision lists the highlighted terms and conditions and notes the Commission's considerations. Overall the Commission considers that the terms and conditions satisfy the requirements of section 3.6 of the Code.

Nominations

The Commission considers that the nomination process proposed by NT Gas meets the requirements of users and potential users in terms of section 3.6 of the Code.

The Commission notes that providing for the user to vary the nomination (up to MDQ) by no later than 3 pm on the business day prior to that day is common practice.

MHQ, MDQ and ACQ

The Commission accepts that the user must establish for each contract year an MHQ, an MDQ and an ACQ that is to apply for the whole contract year.

The Commission considers that it is reasonable to ask the user to establish an MDQ for each delivery/receipt point.

The Commission considers that NT Gas has provided enough margin of error for a user when measuring their MHQ and MDQ.

System Use Gas and Linepack

The Commission accepts that users should supply gas for use as system use gas at their own cost. In addition, the Commission considers that the cost to supply the proportion of user linepack is reasonable. The Commission accepts NT Gas is in its rights to correct a shortfall in linepack, if the quantity of gas supplied by a user as linepack is less then its proportion of users' linepack.

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217 Imbalance charge = Imbalance existing on the last Day of M3 multiplied by the Imbalance rate.

218 Santos submission, 8 September 1999, p. 5.

Overruns, variances and imbalances

The Commission considers that the overruns, variances and imbalance charges are not excessive or restrictive.

In relation to a user's overrun, the Commission considers that NT Gas will provide an authorised overrun unless there are valid reasons, such as limited capacity in the pipeline and/or the user has an unfavourable record in exceeding MDQ.

The Commission accepts that it is within NT Gas' right to request the user to correct an imbalance if it is likely for example to jeopardise the ability of NT Gas to operate the pipeline properly. The Commission considers that NT Gas provides the user with a reasonable time frame to correct the imbalance.

The Commission considers that NT Gas calculates the daily variance, overrun and imbalance fairly, as NT Gas recognises that it may have caused the variation.

Allocation

The Commission considers that NT Gas provides users the flexibility in establishing their own appropriate allocation methodology. It should be noted that the pro-rating based allocation methodology is common practice.

Interruptions and curtailments

The Commission accepts that NT Gas will try to avoid or minimise so far as is reasonably practicable any curtailment of services to users. Accordingly, the Commission is satisfied that NT Gas has identified reasonable events that would justify an interruption and/or curtailment of services.

Liabilities and indemnities

The Commission considers that NT Gas has been reasonable in assessing events that might result in the user being liable or having to pay indemnities.

Gas quality specifications

The Commission notes Santos' concerns about the gas quality specification proposed for the ABDP. However, the Commission is also aware that its role and expertise is as an economic rather than technical regulator, and that it has not conducted a full technical review of this issue.

The Commission does not at this stage propose to require amendments to the proposed access arrangement to change the parameters listed for the gas quality specifications. Instead, it proposes that NT Gas' access arrangement be amended to ensure that any recommendations by the AGA Gas Quality Specification Working Group to adopt a more flexible gas specification in the NT can be reflected in the access arrangement for the ABDP.[219]

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[219] See Final Decision on the access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline, September 1999, p. 79 for further discussion on gas quality specifications.

Proposed Amendment A3.2

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend the access arrangement to state that NT Gas will seek to amend its access arrangement following any recommendations by the AGA Gas Quality Specifications Working Group to adopt more flexible gas specification.

Standard service agreement

While schedule 2 of the access arrangement includes key terms and conditions, the proposed access arrangement does not include the standard service agreement which sets out the terms and conditions on which NT Gas will provide the reference service. NT Gas stated that the standard service agreement will be consistent with the access arrangement.

The Commission is aware that NT Gas cannot at this stage be confident that its standard service agreement is consistent with the terms and conditions which the Commission will approve as part of the access arrangement. The Commission expects that users may be primarily guided as to the terms and conditions on which they will gain access to the ABDP by the content of the standard service agreement. Consequently, the Commission requires an amendment to the ABDP access arrangement to make it clear that, in the event that any apparent inconsistency arises, schedule 2 of the access arrangement prevails over the standard service agreement.

Proposed Amendment A3.3

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must clearly specify that schedule 2 of the access arrangement prevails over the standard service agreement.

Prudential requirements

The Commission notes that the provision for access and requests for services and the queuing policy of the access arrangement requires users and prospective users to meet NT Gas' prudential requirements prior to the user requesting a service or assigning a request on a queue.[220] The prudential requirements that NT Gas requires users and prospective users to meet are not specified in the access arrangement. The Commission considers that it is important for users and prospective users to be aware of all the conditions of use of the ABDP including any prudential requirements. The reasonableness of the terms and conditions of access cannot be assessed by the Commission or interested parties in the absence of NT Gas' prudential requirements.

Accordingly, the Commission proposes an amendment to the ABDP access arrangement for NT Gas to set out the prudential requirements that will apply to users and prospective users in the access arrangement.

[220] NT Gas Access Arrangement, 25 June 1999, Section 1.4, p.8 and Section 6.2, p.18.

Proposed Amendment A3.4

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must include in the access arrangement the prudential requirements relevant for users and prospective users.

3.4 Capacity Management Policy

3.4.1 Code requirements

Section 3.7 of the Code requires an access arrangement to include a statement that the covered pipeline is either a contract carriage pipeline or a market carriage pipeline.

3.4.2 NT Gas' proposal

Section 8 of the access arrangement stated that the ABDP is a contract carriage pipeline.

3.4.3 Submissions by interested parties

No comments were received on this issue.

3.4.4 Commission's considerations

As the access arrangement includes a statement that the ABDP is a contract carriage pipeline, it satisfies the requirements of section 3.7 of the Code.

3.5 Trading Policy

3.5.1 Code requirements

If a pipeline is a contract carriage pipeline, the access arrangement must include a trading policy that explains the rights of a user to trade its right to another person. The trading policy must, amongst other things, allow a user to transfer capacity:

- without the service provider's consent, if the obligations and terms under the contract between the user and the service provider remain unaltered by the transfer; and
- with the service provider's consent, in any other case.

Consent may be withheld only on reasonable commercial or technical grounds and the trading policy must specify conditions under which consent will be granted and any conditions attached to that consent.

3.5.2 NT Gas' Proposal

Section 5 of NT Gas' access arrangement stated that users could trade rights in three circumstances. These were:

- a user may make a 'bare transfer' without the consent of NT Gas provided that prior to utilising it the transferee notifies NT Gas of the portion of contracted capacity subject to the bare transfer and of the nature of the contracted capacity subject to the bare transfer.

- a user may only transfer or assign all or part of its contracted capacity other than by way of a bare transfer with the prior consent of NT Gas, which will only be withheld on reasonable commercial or technical grounds, and which may be given subject to reasonable commercial or technical conditions.

- a user may only change the receipt point and/or delivery point specified in a service agreement with the prior consent of NT Gas, which will only be withheld on reasonable commercial or technical grounds, and which may be given subject to reasonable commercial or technical conditions.

3.5.3 Submissions by interested parties

No comments have been received on this issue.

3.5.4 Commission Considerations

The Commission considers that the trading policy in the access arrangement meets the minimum requirements of the Code, specifically, sections 3.9 to 3.11.

3.6 Queuing Policy

3.6.1 Code requirements

Sections 3.12 to 3.15 set out the Code's requirements for a queuing policy. An access arrangement must include a queuing policy for determining the priority given to users and prospective users for obtaining access to a covered pipeline and for seeking dispute resolution (under section 6 of the Code). The purpose of the queuing policy is to allocate capacity where there is insufficient capacity to satisfy the needs of all users and potential users that have requested capacity.

Section 3.13 of the Code states that a queuing policy must be set out in sufficient detail to enable users and prospective users to understand in advance how it will operate. It must also, to the extent reasonably possible, accommodate the legitimate business interests of the service provider, and of users and prospective users, and generate economically efficient outcomes. Section 3.14 of the Code allows the regulator to require the queuing policy to deal with any other matter the relevant regulator thinks fit taking into account the matters listed in section 2.24.

3.6.2 NT Gas' Proposal

Section 6 of the access arrangement contained the service provider's queuing policy. Where there is insufficient capacity to satisfy a user's request to obtain a service from NT Gas, a queue will be formed. A queue will include all relevant requests which cannot be satisfied. Where an offer has been made in response to a request received prior to formation of the queue, the request will take first position in the queue.

At the time a request is placed in a new or existing queue, NT Gas will advise the prospective user of:

- its position on the queue;
- the aggregate capacity of requests which are ahead on the queue;
- its estimate of when capacity may become available; and
- the size of any surcharge that may apply to developable capacity.

NT Gas will update these details when the relative position of a request or the timing of available developed capacity changes.

Once on a queue, a prospective user may reduce but not increase the capacity sought in its request. An assignment of a request can be made to a bona fide purchaser of the prospective user's business or assets.

A request for service may lapse and be removed from the queue if:

- the prospective user does not respond to NT Gas' request for confirmation of the request within the specified 14 days;
- the prospective user notifies NT Gas that it does not want to proceed with the request; or
- the entity to whom the prospective user assigns its request does not meet NT Gas' prudential requirements.

A request will not lapse in the event that there is a dispute. The request will retain its priority until the dispute is resolved in accordance with the Code.

When capacity is made available which meets the requirements of any request in a queue, that capacity will be progressively offered to each prospective user in the queue in order of priority. NT Gas will advise each of those prospective users of its plans to make capacity available, and the terms and conditions on which the capacity will be available.

A prospective user will have 30 days after an offer is made to enter into a service agreement, failing which the request will lapse or lose priority to those entering into such a service agreement.

Priority of Prospective Users in Obtaining Services

Clause 6.4 sets out the manner in which priority is to be assigned to requests where a queue has been formed under clause 6.1. The fourth dot point in clause 6.4 provides that where a user exercises a contractual right in force as at 25 June 1999 to increase capacity reservation under its existing service agreement, that increase will be treated as a request and will be placed at the head of the queue, notwithstanding that priority would otherwise be accorded to any earlier requests.

In relation to prospective users, the proposed queuing policy is as follows:

- the earliest date a complete request is received by NT Gas; and
- if the request is for a reference service it will have priority over a request for a negotiated service or a request for an interruptible service.

3.6.3 Submissions by interested parties

Woodside submitted that pre-emptive rights to capacity for existing users could be used to restrict access for new entrants. Woodside stated that at the very least existing users should need to demonstrate a business requirement for that capacity.

3.6.4 Commission's considerations

NT Gas proposed in clause 6.4 of the access arrangement, that an existing user with a contractual right in force as at 25 June 1995 will, have pre-emptive rights over capacity reservation.

Sections 2.25, 2.47 and 6.18 of the Code all state that the regulator or arbitrator must not make a decision that has the effect of depriving a person of an existing contractual right, 'other than an Exclusivity Right which arose on or after 30 March 1995'.

The Commission has examined the pre-existing contracts and has been unable at this stage to identify any provisions, which would be defined as an exclusivity right.

However, the Commission is concerned that the fourth dot point of clause 6.4 does not reasonably accommodate the legitimate business interests of prospective users because it establishes a principle in the queuing policy where they could be denied access to capacity. Such a principle has the potential to diminish competition in downstream markets in the future.

Further, the Commission is concerned that clause 6.4 could become established in the access arrangement and, hence, form the basis of future access arrangements.

Consequently, the Commission requires that the fourth dot point of clause 6.4 must be removed. The Commission does not consider that the removal of this dot point would deny existing users of a contractual right.

Proposed Amendment A3.5

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must remove the fourth dot point of clause 6.4.

3.7 Extensions and Expansions policy

3.7.1 Code requirements

Section 3.16 of the Code requires an access arrangement to have an extensions and expansions policy. The policy is to:

- set out the method to be applied to determine whether any extensions to or expansions of the system's capacity will be treated as part of the covered pipeline;
- specify the impact on reference tariffs of treating an extension or expansion as part of the covered pipeline; and
- outline the conditions on which the service provider will fund new facilities and provide a description of those new facilities.[221]

In relation to coverage, the service provider has the option of treating the extension as either:

- part of the network; or
- a stand-alone pipeline, in which case the service provider will provide written notice to the regulator prior to the extension entering into service. The service provider will have the option of including the stand-alone pipeline as part of the network at any subsequent review of the access arrangement.

In specifying the impact on reference tariffs, the service provider has a number of options set out in section 8 of the Code, for example:

- the part of the new facilities investment that is included as part of the network that does satisfy the requirements of section 8.16(a) of the Code, the service provider may implement a surcharge in accordance with section 8.25 and 8.26 of the Code and the reference tariff will remain unchanged; or
- the part of the new facilities investment that is included as part of the network that does satisfy the requirements of section 8.16 of the Code, the service provider may require a new incremental user to make a lump sum contribution (as a capital

[221] This section is linked to section 6.22(e) of the Code which precludes a service provider from being required to fund new facilities investment in an access dispute unless the service provider has agreed to fund a new facility under certain conditions. This policy recognises that it may not be appropriate for the regulator to agree to reference tariffs being determined on the basis of forecast of new facilities investment when required.

contribution) to the cost of the new facilities investment and the reference tariffs may be determined for example, in accordance with section 8.2 of the Code.[222]

An extensions and expansions policy could specify that a review will be triggered and that the service provider must submit revisions to the access arrangement pursuant to section 2.28 of the Code.

3.7.2 NT Gas' proposal

The extensions and expansions policy is described in Section 7 of NT Gas' access arrangement. NT Gas proposes that in the event that it elects to extend the pipeline, then that extension will, at the election of NT Gas, be treated as part of the ABDP for the purposes of this access arrangement. Reference tariffs for existing delivery points will not be affected by any extension.

In the event that NT Gas expands the capacity of the pipeline, NT Gas will elect either to treat the expanded capacity as:

- part of the ABDP for the purposes of this access arrangement and NT Gas will exercise its discretion to submit proposed revisions to this access arrangement under section 2 of the Code; or

- not part of the ABDP for the purposes of this access arrangement and NT Gas will lodge a separate access arrangement in respect of any of that expanded capacity which is not subject to contract.

3.7.3 Submissions from interested parties

Nabalco submitted that the expansions and extensions policy was only suitable for a minor change and if a major expansion occurred then the entire access arrangement would need to be reviewed.[223]

3.7.4 Commission's Considerations

The Commission is required to assess whether the extensions and expansions policy is appropriate given the principles set out in section 2.24 of the Code. The Commission is not satisfied at this stage that the extensions and expansions policy as it currently stands, is consistent with the principles set out in section 2.24 of the Code. In particular, the Commission is not satisfied that section 2.24(e) of the Code has been met.

Section 2.24(e) of the Code states:

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

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222 Section 8.18 of the Code states that a service provider can undertake new facilities investment that does not satisfy requirements of section 8.16, however, the capital base may be increased only by that part of the new facilities investment which does satisfy section 8.16 of the Code.

223 Nabalco submission , 9 September 1999, p. 2.

The Commission considers that there is a possibility that the pipeline may need to be expanded to meet the growing gas demand in Darwin. The pipeline is close to or at capacity currently. As such, a need to expand the pipeline could arise if the Timor Sea project does not go ahead.

If such an expansion were undertaken the Commission would want to ensure that the pipeline owner was not in a position to exploit market power, irrespective of the expansion. One option is for the expansion to be included as part of the covered pipeline and the cost of expansion rolled into the capital base. Currently, this option could be eliminated entirely at the service provider's discretion. Such an outcome may not be in the public interest and therefore would not be consistent with section 2.24(e) of the Code.

If any extension/expansion is treated as part of the covered pipeline, the impact on the reference tariffs will depend on the extent that the new investment satisfies section 8.16 of the Code.

The Commission requires NT Gas to amend its proposed extensions and expansions policy to require it to obtain the Commission's consent before electing to omit new facilities from the covered pipeline.

Proposed Amendment A3.6

In order for NT Gas's access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must specify in the access arrangement that it will obtain the Commission's consent before electing to omit new facilities (either extensions or expansions) from the covered pipeline.

3.8 Review and expiry of the access arrangement

3.8.1 Code requirements

Section 3.17 of the Code requires an access arrangement to include a date upon which the service provider must submit to the regulator a revised access arrangement (revisions submission date) and a date upon which the revisions are intended to commence (revisions commencement date).

In deciding whether these two dates are appropriate, the regulator must have regard to the objectives contained in section 8.1 of the Code. Having done so, the regulator may require an amendment to the proposed access arrangement to include earlier or later dates. The regulator may also require that specific major events be defined as a trigger that would oblige the service provider to submit revisions before the revisions submission date (section 3.17 (ii)).

An access arrangement period accepted by the regulator may be of any duration. However, if the period is greater 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 access arrangement are based, subsequently proved to be incorrect (section 3.18 of the Code). The Code provides examples of such mechanisms for guidance. Thus a regulator could consider triggers for early submission of revisions based on:

- divergence of the service provider's profitability or the value of services reserved in contracts from a specified range; or
- changes to the type or mix of services provided.

The regulator could require a service provider to return to users some or all revenue of profits in excess of a certain amount.

Finally, the revisions commencement date is not a fixed date. The date is subject to variation at the time the regulator approves the revisions pursuant to section 2.48 of the Code. This section states in part:

> Subject to the Gas Pipelines Access Law, revisions to an access arrangement come into effect on the date specified by the Relevant Regulator in its decision to approve the revisions (which date must not be earlier than either a date 14 days after the day the decision was made or…. The revisions Commencement Date).

3.8.2 NT Gas' Proposal

NT Gas proposed to submit revisions to the access arrangement four years and six months from the commencement of this access arrangement, and that the revisions would commence on the later of;

- the date being 6 months after the revisions submission date; and
- the date on which the approval by the regulator of the revisions to the access arrangement takes effect under the Code.

3.8.3 Submissions by interested parties

Woodside contended that the review commencing after 4 years and 6 months is much too late, and argue;

> The review of this Access Arrangement should be completed at least two years from expiry to provide certainty to prospective investors after the initial five-year period.[224]

Nabalco suggested that the term and review section should contain a trigger mechanism to review the access arrangement prior to the revisions submission date. It contended a suitable trigger would include Nabalco entering into an agreement with a gas supplier for supply of gas to Gove.[225]

3.8.4 Commission's Considerations

NT Gas has proposed a revisions submission date and a revisions commencement date in accordance with the requirements of the Code.

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[224] Woodside submission, 9 September 1999, p. 1.

[225] Nabalco submission, 9 September 1999, p. 2.

As noted in section 3.2.6 of the Draft Decision, the Commission has proposed that a trigger mechanism should be included in the access arrangement, given the event that Timor Sea gas comes onshore to Darwin. This may require the service provider to include a service description and tariffs for a back haul service in the event of gas coming onshore. This may, however, be a difficult regime to manage, as there is uncertainty for both the access seeker and the service provider as to what the prices and terms and conditions will be for the back haul service.

An access arrangement for the initial access arrangement period will commence in accordance with section 2.26 of the Code only after the Commission is satisfied that it meets the minimum requirements of the Code. The term of the access arrangement is not expected to exceed 5 years by the time further public consultation held, and a final decision and final approval document issued.

4. Information provision and performance indicators

4.1 Information provision

4.1.1 Code requirements

In conjunction with its proposed access arrangement, a service provider is required to submit access arrangement information. The access arrangement information must contain sufficient information to assist all parties in understanding the proposed access arrangement.

According to section 2.7 of the Code, the access arrangement information provided may include any relevant information, but must at least contain the categories of information described in Attachment A to the Code, which is summarised in Box 4.1 below.[226]

Box 4.1 Summary of Attachment A information

The information required is divided into six categories:

Category 1: access and pricing principles

Tariff determination methodology; cost allocation approach; and incentive structures.

Category 2: capital costs

Asset values and valuation methodology; depreciation and asset life; committed capital works and planned capital investment (including justification for); rates of return for equity and debt; and debt/equity ratio assumed.

Category 3: operations and maintenance costs

Fixed versus variable; cost of services by others; cost allocation between, for example, pricing zones, and cost categories.

Category 4: overheads and marketing costs

Costs at corporate level; regulated versus unregulated; cost allocation between, for example, pricing zones, and categories of assets.

Category 5: system capacity and volume assumptions

Description of system capabilities; map of piping system; average and peak demand; existing and expected future volumes; system load profiles and customer numbers.

Category 6: key performance indicators

Indicators used to justify 'reasonably incurred' costs.

Under section 2.8 of the Code, information included in the access arrangement information may be categorised or aggregated to the extent necessary to ensure that disclosure of the information is not in the opinion of the relevant regulator, unduly harmful to the legitimate business interests of the service provider, a user or prospective user.

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226 Attachment A of the Code is replicated at Appendix C of this Draft Decision.

If the relevant regulator is not satisfied that the access arrangement information meets the requirements of the Code, it may, of its own volition, require the service provider to make changes to the access arrangement information. Likewise, if requested to do so by any person, the relevant regulator must review the adequacy of the access arrangement information.

If the relevant regulator requires the service provider to change the access arrangement information, it must specify the reasons for its decision and allow the service provider a reasonable time to make the changes and resubmit the access arrangement information.

This chapter relates specifically to access arrangement information, which is provided for users and prospective users. However, it is important to note that the regulator also has much wider information gathering powers under the GPAL. If the regulator has reason to believe that a person has information or a document that may assist the regulator in the performance of any of the regulator's prescribed duties under the GPAL, the regulator may require that person to provide the information or a copy of the document to it.[227] Section 2.8 of the Code states that nothing in that section limits the regulator's power under GPAL to obtain information, including information in an uncategorised or unaggregated form. The Code and the GPAL place limitations on the discretion of the regulator to disclose information received that has been identified to be of a 'confidential or commercially sensitive nature'.[228]

4.1.2 NT Gas' proposal

NT Gas submitted access arrangement information in conjunction with the access arrangement on 25 June 1999.

In response to a request by the Commission pursuant to section 2.9(a) of the Code, NT Gas submitted further access arrangement information on September 1999.

4.1.3 Submissions by interested parties

No submissions were received on this issue.

4.1.4 Commission's Considerations

Following receipt of NT Gas' access arrangement and access arrangement information on 25 June 1999, the Commission assessed the access arrangement information for compliance with the requirements of 2.6 and 2.7 of the Code. Pursuant to section 2.9(a) of the Code, the Commission determined that the access arrangement information did not satisfy those requirements, and decided to seek further information from NT Gas.

The Commission assessed the information provided by NT Gas in its entirety and concluded that the original access arrangement information, together with the additional information, satisfied the requirements of the Code with respect to the

227 Section 41, Gas Pipelines Access (NSW) Act 1988.

228 Section 7.11 and 7.12 of the Code and section 42, Gas Pipelines Access (NSW) Act 1988.

proposed access arrangement. Changes proposed in this Draft Decision will require need for further revisions to the access arrangement information. Consequently, further assessment of the access arrangement information provided by NT Gas will be required prior to the Final Decision.

On 20 August 1999, the Commission issued a notice under section 41 of the GPAL on NT Gas for required information. This information included: the existing transportation contracts for the ABDP; a copy of the independent auditors' report of the asset valuation and electronic copy of all financial models used in developing the access arrangement information. In addition to issuing the section 41 notice, the Commission sought information from NT Gas on a number of issues, including justification for NT Gas' proposed WACC of 11 per cent and accelerated depreciation of the regulatory asset base.

4.2 Key performance indicators

4.2.1 Code requirements

The Code identifies the need for key performance indicators (KPIs) to be disclosed by service providers to interested parties. 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

- service provider's KPIs for each pricing zone, service or category of asset.

Section 8.6 of the Code allows the regulator to 'have regard to any financial and operational performance indicators it considers relevant in order to determine the level of costs within the range of feasible outcomes under section 8.4 that is most consistent with the objectives contained in section 8.1 of the Code.' The regulator must then identify the indicators and provide an explanation of how they have been taken into account (section 8.7 of the Code).

4.2.2 NT Gas' proposal

NT Gas identified a number of limitations on the usefulness of publicly available information relating to the performance of the Australian natural gas transmission industry.[229] In particular, NT Gas noted that much of the information publicly available relates to publicly owned pipelines prior to their privatisation, and that private companies have declined to release performance information on the basis of commercial sensitivity and restrictions on disclosure. Further, NT Gas noted the difficulty of 'normalising' pipelines for such things as diameter, length, geography and topography of location and operational characteristics, to yield meaningful comparisons.

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[229] Access Arrangement Information, p. 43

Nevertheless, NT Gas recognised the need for the regulator to benchmark performance and has provided a number of measures, which it considers will contribute to the development of meaningful industry performance measures over time.

Operating Costs

NT Gas' total operating costs for the year ending 30 June 1999 were estimated to be $6.4m. NT Gas considered that $6.4m was below what it considered to be an indicative operating cost, that is $6.7m, as determined by the application of industry's accepted 'rules of thumb'.

NT Gas also provided some analysis based on comparisons with;

- estimated total operating costs ($/1000km) of other Australian pipelines; and
- operating costs of US pipelines.

NT Gas acknowledges that the information provided for some of these pipelines is dated and that there are significant differences in these pipeline systems. However, NT Gas stated that total operating costs for the ABDP are efficient.

4.2.3 Submissions by interested parties

PAWA criticised the use of key performance indicators which compare NT Gas' proposed operating and maintenance expenditure for the ABDP with other Australian and US pipelines. PAWA considered that it is 'overly simplistic' and 'meaningless' to compare operating costs between pipelines on a dollars per 1000 km basis. In particular:

> 'The figure produced provides no meaningful insight about NT Gas' efficiency in operating the pipeline, compared with other Pipelines. There are no benchmarks. The primary reason for this is the wildly varying conditions and configurations of each Pipeline apart from length which impact on operating costs, such as pipe diameter, throughput, number of compressors, terrain, location (remote/urban) and the number of users' [230]

4.2.4 Commission's considerations

The Commission noted in its *Victorian Final Decision* the challenges in identifying KPIs and benchmarks especially in a newly deregulated commercial environment such as the Victorian natural gas industry.[231] At that stage the Commission stated its intention to work closely with the Victorian service providers to establish appropriate KPIs but that in the short to medium term, it would have regard to financial performance indicators pursuant to section 8.6 of the Victorian Code. The Commission also considered the use of benchmarks such as load factor and energy delivered per employee which are set out by the Steering Committee on National Performance Monitoring of Government Trading Enterprises as a basis for developing non-financial indicators for TPA.

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[230] Clayton Utz, 17 November 1999, NT Government and PAWA submission to the ACCC on Access Arrangement for the Amadeus Basin to Darwin Gas Pipeline, p. 8

[231] ACCC, Final Decision – Victoria, p. 157.

However, arrangements whereby NT Gas has contracted activities out to other companies in the AGL Group create particular difficulties when using of some of the benchmarks mentioned above. As NT Gas has no employees, ‘per employee’ measures are not directly available. Further, to the extent these contracted entities are primarily engaged in activities unrelated to the ABDP, there may be factors such as economies of scale and scope that blur comparisons with pipelines that would on face value appear to be comparable with the ABDP (for example, stand-alone pipelines of similar diameter and length).

The Commission also recognises the limitations of KPI information noted by NT Gas. Nevertheless, the Commission welcomes NT Gas’ contribution to the available body of benchmarking information. Based on the information provided by NT Gas regarding operating costs the ABDP’s performance over the long term appears to be reasonable.

In assessing the proposed access arrangement, the Commission has not considered financial performance indicators in terms of section 8.6 of the Code.

Further discussion on the Commission’s views regarding the use of financial indicator analysis is included in the *Draft Regulatory Principles* May 1999.

5. Draft decision

Pursuant to section 2.13(b) of the Code, the Commission proposes not to approve NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline in its present form. This *Draft Decision* states the amendments (or nature of amendments, as appropriate) which would have to be made in order for the Commission to approve the proposed access arrangement.

Appendix A: Submissions from interested parties

Woodside Energy Ltd and Shell Development (Australia) Pty Ltd, 9 September 1999

Nabalco Pty Ltd, 9 September 1999

NT Power Generation Pty Ltd, 12 September 1999

Santos Ltd, 17 September 1999

Northern Territory of Australia and Power and Water Authority, 17 November 1999

Northern Territory of Australia and Power and Water Authority, 29 February 2000

Appendix B: Breakdown of the ORC valuations for each Zone

	Zone 1: Amadeus Basin to Warrego	**Zone 2: Warrego to Mataranka**	**Zone 3: Mataranka to Darwin**	**Total**
Transmission pipelines	$120,600	$79,700	$64,400	$264,700
Compressors	$10,400	$10,400		$20,800
Regulating, metering, odourisation	$2,600	$800	$3,600	$7,000
SCADA & communications	$2,100	$1,400	$1,200	$4,700
Operations facilities	$3,800	$2,600	$1,900	$8,300
Sub total	$139,500	$94,900	$71,100	$305,500
Interest during construction	$7,700	$5,200	$3,900	$16,800
Total	**$147,200**	**$100,100**	**$75,000**	**$322,300**

Note: native title allowance included under pipelines