N.T. GAS PTY. LIMITED
ACN 050 221 415

ACCESS ARRANGEMENT INFORMATION FOR THE AMADEUS BASIN TO DARWIN PIPELINE

February, 2003

N.T. Gas Pty. Limited
Access Arrangement Information
for Amadeus Basin to Darwin Pipeline

CONTENTS

1 INTRODUCTION

1.1 Overview of the Access Arrangement Information

This document is the Access Arrangement Information in relation to the Access Arrangement for the Amadeus Basin to Darwin Pipeline (**"ABDP"**). It has been submitted by N.T. Gas Pty. Limited ACN 050 221 415 (**"NT Gas"**) pursuant to the Gas Pipelines Access Law and Section 2.2 of the National Third Party Access Code for Natural Gas Pipelines (**"Code"**). As the operator of the ABDP, NT Gas is the Service Provider in respect of the Pipeline.

The purpose of this document is to set out such information as is necessary to enable Users and Prospective Users to understand the derivation of the elements of the Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Code[1].

In accordance with the Code[2], the form of regulation adopted in this Access Arrangement is a "Price Path" methodology in respect of the determination of Reference Tariffs.

Terms used in this Access Arrangement Information have the meanings given to them in Schedule 1 of the Access Arrangement or the Code as the case may be.

Attachment 1 to this document shows the information categories listed in Attachment A of the Code and indicates where this information is contained within this document.

1.2 Background

In the mid 1960s natural gas was discovered at the Amadeus Basin, near Alice Springs, in both the Palm Valley and Mereenie fields. 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 the Power and Water Corporation[3] at Alice Springs, 150kms from the Palm Valley gas field[4].

In 1984 the Northern Territory (**"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 first gas delivered to the Power and Water Corporation in January 1987.

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1 Section 2.6.
2 Section 8.3(a).
3 Then known as the Northern Territory Electricity Commission.
4 Gas is delivered to Alice Springs through the Palm Valley to Alice Springs Pipeline which has recently been sold by Holyman Limited to Envestra Limited.

In 1988 the AGL Group acquired through wholly owned subsidiaries[5] 96% of NT Gas, the other shareholders being Darnor Pty. Limited (an NT Government company) 2.5% and Centrecorp Aboriginal Investment Corporation Pty. Limited (a company owned by the Central Land Council) 1.5%. In June 2000, AGL floated its pipeline interests, including its share of NT Gas, through a transfer to Australian Pipeline Trust, a managed investment vehicle.

Ownership of the ABDP is vested in a consortium of banks and the pipeline is leased to NT Gas as trustee of the Amadeus Gas Trust. The provisions of the Trust Deed specify the manner in which revenue received from the operation of the ABDP is to be distributed to beneficiaries under the Trust who include the shareholders of NT Gas.

Since the commissioning of the ABDP a number of lateral pipelines have been constructed to interconnect into the ABDP (all of which do not form part of the ABDP for the purposes of this Access Arrangement) including the:

- McArthur River pipeline was commissioned in February 1995 and gas was supplied to fuel the power station at the McArthur River mine.
- Darwin City Gate to Berrimah pipeline was commissioned and gas supplied to industrial users in the Darwin environs in January 1996.
- Mt Todd pipeline was commissioned in October 1996 and gas supplied to fuel the power station at the Mt Todd mine. In November 1997 mining operations were suspended at the mine after the mine owner Pegasus Gold Australia Pty Limited became insolvent forcing the recently commissioned pipeline infrastructure out of service. The Mt Todd lateral remains idle.

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

There is currently no available firm capacity in 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[6].

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5 Agex Pty Limited and Sopic Pty Limited.

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

1.3 Important Notice

This Access Arrangement Information for the ABDP replaces any previous, proposed or revised Access Arrangement Information documents submitted for the ABDP.

The Access Arrangement Information generally reflects the Australian Competition and Consumer Commission's Final Decision dated 4 December, 2002 on the Access Arrangement proposed by NT Gas for the ABDP.

2 ACCESS & PRICING PRINCIPLES

2.1 Factors to be taken into account by regulator

The Code[7] requires the Regulator to take the following into account in deciding whether to approve a proposed Access Arrangement:

a) Service Provider's legitimate business interests and investment in the Covered Pipeline: *the Total Revenue determined by the Regulator, the design of the Reference Tariffs and the recognition of existing contractual rights and obligations is designed to protect these interests and investment;*

b) firm and binding contractual obligations of the Service Provider or other persons: *the Rebate Mechanism, the nature of the Interruptible Service and the queuing policy reflect these obligations;*

c) operational and technical requirements required for safe and reliable operation of the Covered Pipeline: *the terms and conditions of the Services are designed to achieve these objectives;*

d) economically efficient operation of the covered Pipeline: *this is incorporated in the operating costs for the ABDP and the forecast capital expenditure*;

e) public interest, including in having competition in markets (whether or not in Australia): *the public interest in competition is accommodated through cost-reflective pricing, and recovery of only efficient capital and non-capital costs; the public interest in safe and reliable operation of the ABDP is accommodated through recovery of such costs and the general terms and conditions;*

f) interests of Users and Prospective Users: *the Interruptible Service and the Negotiated Service are designed to recognise these interests for Prospective Users while recognising the rights and obligations of existing Users.*

2.2 Tariff Principles

The Code[8] states that a Reference Tariff and Reference Tariff Policy should be designed with a view to achieving the following objectives:

a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service: *the Total Revenue determined by the Regulator recognises the capital costs of the ABDP (through determination of the initial Capital Base) and efficient operating costs*;

7 Section 2.24.
8 Section 8.1.

b) replicating the outcome of a competitive market: *this is reflected through the determination of the initial Capital Base and efficient operating costs, and adoption of zonal pricing;*

c) ensuring the safe and reliable operation of the Pipeline: *this is incorporated in the operating costs for the ABDP and forecast capital expenditure, and is also reflected in the terms and conditions of the Services*;

d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries: *this is accommodated through cost-reflective zonal pricing and recovery of efficient capital and non-capital costs*;

e) efficiency in the level and structure of the Reference Tariff: *this is reflected through zonal pricing and throughput tariffs*; and

f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services: *this is provided through the incentive mechanism described in Section 2.6 of this Access Arrangement Information*.

2.3 Reference Tariff Determination

Reference Tariffs for the Access Arrangement Period will follow a price path approach[9] with the Total Revenue calculated according to the cost of service methodology during this time[10].

As detailed in Section 3, the derivation of the Reference Tariff involves:

a) determination of the Total Revenue for the ABDP;
b) allocation of the Total Revenue to the three ABDP pricing zones;
c) calculation of a per gigajoule throughput tariff for each zone based on estimated throughput in that zone;
d) a once-off tariff reduction in the year 2007/2008 (through a factor "Y") to reflect the cessation of an additional cost component in June 2007[11]; and
e) smoothing of the zonal throughput tariffs over the Access Arrangement Period based on a smoothing factor “X” (whilst maintaining the NPV of the Total Revenue during this period).

2.4 Tariff Structure

The Code[12] requires that an Access Arrangement must include a Reference Tariff for:

- at least one Service that is likely to be sought by a significant part of the market; and

- each Service that is likely to be sought by a significant part of the market and for which the Regulator considers a Reference Tariff should be included.

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9 Code Section 8.3(a).
10 Section 8.4.
11 Amendment FDA 3.8
12 Code Section 3.3.

The Reference Service in the Access Arrangement is a standard transportation Service where gas is received into the pipeline at any point, and delivered to any other point on the pipeline downstream of the receipt point. Having regard to its experience in operating the pipeline, NT Gas believes this Service is most likely to be sought by prospective users as it reflects the usage of the pipeline to date and the nature of the market served by the pipeline.

The Access Arrangement also offers a Interruptible Service – in which receipt and transportation will be curtailed where capacity is not available – in recognition that there may be a demand for such a Service. As it is not possible at this time to quantify that demand, or the capacity which will be available from time to time for that Service, NT Gas has not offered it as a Reference Service.

2.4.1 Reference Tariff

The Reference Tariff structure for the ABDP during the initial Access Arrangement Period consists of a throughput tariff for each of the three pricing zones. Consistent with usual industry practice, the throughput tariff has the following features:

- load factor adjustment (which is usual for pipelines as a means to adjust throughput tariffs to reflect the pipeline capacity actually required to deliver the gas);
- provision for overruns once the pipeline achieves Contracted Capacity of 85%; and
- provision for a minimum annual bill (which requires payment for a minimum annual quantity of gas being delivered).

This tariff structure is designed:

- to encourage efficient use of the ABDP by providing a financial incentive to Users to take active steps to implement an effective load management system; and
- to the extent commercially and technically reasonable, ensure users of the Reference Service pay for that Service on the basis of the cost of providing the Reference Service (ie according to their reasonable use of the assets).

2.4.2 Zonal Tariffs

The existing contracts on the ABDP are on a "postage-stamp" basis - ie the one tariff applies for receipt and delivery of gas for any point along the pipeline. Such a pricing structure is common when a pipeline project is underwritten by a single user and a significant portion of that user's load is at the end of the pipeline. Such is the case with the ABDP[13].

NT Gas recognises that maintaining such a pricing structure has the potential to impede growth in the utilisation of the ABDP. This is particularly in the case of price sensitive projects which are located only part way along the pipeline, but which, under a postage stamp tariff, would be charged for delivery of gas as if that gas was transported through the entire length of the pipeline.

[13] The ABDP ends at the outlet meter for the Channel Island Power Station.

In an attempt to develop the market for pipeline Services[14] and to replicate the outcomes of a competitive market[15], the Reference Tariff for the ABDP is structured on a three zone basis whereby 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. A detailed description of the zone boundaries is in Section 5.2.

2.4.3 Interruptible Service

The Interruptible Service has similar terms and conditions as the Reference Service, but it has the following differentiating features:

- provision for interruptibility;
- no load factor adjustment; and
- no provision for a minimum annual bill.

By providing this Interruptible Service, NT Gas is encouraging use of the ABDP by those Prospective Users who may have gas consumption requirements that are able to utilise pipeline capacity which will not uniformly be available.

2.5 Cost allocation

As there is only one Reference Service offered, the Reference Tariff for the Reference Service is designed to recover the whole of the Total Revenue for the ABDP[16]. The allocation of Total Revenue into each of the three pricing zones is detailed in Sections 3.4 and 4.4.

The zonal pricing, and throughput tariff, is designed to ensure that to the maximum extent technically and commercially reasonable, the portion of Total Revenue to be recovered from sales of the Reference Tariff to a particular User reflects the costs of providing that Service[17]. The adoption of zonal tariffs is more cost-reflective of a user's utilisation of pipeline Services than a single postage stamp tariff, while avoiding the complexities and expense of administering a strictly distance-based tariff. A throughput tariff, adjusted for load factor, has been adopted as it overcomes the rigidity which can be associated with requirements that capacity must be booked and paid for. It also maintains some consistency with existing transportation contracts on the ABDP.

[14] This is to be one of the objectives of a Reference Tariff and Reference Tariff Policy – see Code section 2.1(f).

[15] A postage stamp tariff may make a pipeline vulnerable to bypass where the tariff for transportation would be more reflective of the distance the gas is transported. Replicating the outcomes of a competitive market is one of the objectives of a Reference Tariff and Reference Tariff Policy – see Code section 2.1(b).

[16] Code Section 8.38 requires that to the maximum extent that is commercially and technically reasonable, a Reference Tariff should be designed to recover the portion of Total Revenue that reflects the costs of providing that Reference Service.

[17] This is required under Code Section 8.42.

2.6 Incentive Mechanism

The incentive structures in the Reference Tariff and the Access Arrangement are:

1) The level of Reference Tariff is determined to encourage NT Gas to develop the volume of sales of Services and to minimise its costs of providing Services [18];

2) The Reference Tariff will apply during each year of the Access Arrangement Period regardless of whether the estimates underpinning the Reference Tariffs (eg volume and cost estimates) are realised[19]; and

3) The Interruptible Service is designed to encourage NT Gas to increase pipeline utilisation and to minimise the costs of providing pipeline Services[20]. At the same time it recognises - through the treatment of the revenue from sales of the Service – existing contractual arrangements[21].

These incentive mechanisms provide an incentive to NT Gas to reduce total operating costs on the one hand, and increase pipeline throughput on the other.

2.7 Other Revenue

The Reference Tariff has been designed to recover the Total Revenue for the ABDP. No allowance has been made for other revenue that may accrue from any other charges relating to the provision of Reference Services (ie Variance, Overrun or Imbalance charges) as these are not considered material.

[18] Code Section 8.46(a) and (b).
[19] Such an incentive mechanism is contemplated by Code Section 8.45(a).
[20] Section Code 8.46(a) and (b).
[21] See Section 1.2 of this Access Arrangement Information for a discussion of the obligations imposed on NT Gas through the Amadeus Trust.

3 CAPITAL COSTS

3.1 Initial Capital Base

The Code requires that an Initial Capital Base (ICB) be established for the initial Access Arrangement for a Covered Pipeline. The Code[22] also addresses the valuation of Covered Pipelines that were in existence at the commencement of the Code. The ABDP is one such pipeline, and pursuant to the Code[23], factors to be considered in establishing the ICB for the ABDP are:

a) the value that would result from taking the actual capital cost of the Covered Pipeline and subtracting the accumulated depreciation for those assets charged to Users (or thought to have been charged to Users) prior to the commencement of the Code (ie Depreciated Actual Cost – DAC);

b) the value that would result from applying the DORC methodology;

c) the value that would result from applying other well recognised asset valuation methodologies;

d) the advantages of each valuation methodology applied above;

e) international best practise of pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries;

f) 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;

g) the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code;

h) the impact on the economically efficient utilisation of gas resources;

i) the comparability with the cost structure of new pipelines that may compete with the Covered Pipeline;

j) the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase; and

k) any other factors the Regulator considers relevant.

The Code provides further[24] that, for existing pipelines, the value of the ICB normally should not fall outside the range of values defined by DAC and DORC.

22 Sections 8.10 and 8.11.
23 Section 8.10.
24 Section 8.11

3.1.1 Depreciated Optimised Replacement Cost

NT Gas has established a DORC value for the ABDP of $336.3 million as at 1 July 2001.

3.1.2 Initial Capital Base

In arriving at an initial capital base (ICB) the Final Decision considers the above factors recognising, in particular, the uncertainty surrounding utilisation of the pipeline beyond 2011.

The Final Decision (Amendment FDA2.1) requires that the ICB for ABDP assets be set at $228.5 million as at 1 July 2001.

3.1.3 Depreciation

The Regulator has accepted that the public interest is served by NT Gas being able to recover its investment in the ABDP, and the Final Decision provides for accelerated depreciation to a residual value for leased pipeline assets of $61.84 million in 2011. The Final Decision (Amendment FDA3.3) requires that the following depreciation schedule be adopted:

Depreciation schedule (nominal) for 2002-2011

Year ending 30 June	Depreciation ($m)
2002	14.12
2003	15.53
2004	17.09
2005	18.80
2006	20.75
2007	14.44
2008	12.49
2009	13.09
2010	13.71
2011	14.35

3.1.4 Economic Life and Remaining Economic Lives

Based on NT Gas's experience in operating a high pressure transmission pipeline, various recent access arrangements proposed by service providers[25] and submissions of industry participants and decisions of Regulators, economic lives for the various system assets making up the ABDP have been established. These are set out in the table below together with the average remaining economic life of each of the asset

[25] With particular reference to Access Arrangements submitted by AGLP for the Central West Pipeline, TPA for the Victorian Gas Transmission System, Great Southern Energy Gas Networks for its distribution system and Envestra for the South Australian Distribution System.

classes noted. Minimum remaining lives of all of the assets classes in the table have been set at 5 years, apart from SCADA which has no minimum remaining life.

ABDP System Assets
Economic Lives (from installation and remaining years)

Asset	Economic Life (years)	Average Remaining Economic life (1 July 2001) (years)
Transmission Pipeline (coated and CP protected): Constructed 1986	80	65
Compressor Stations:		
Rotating Equipment	25	20
Station Facilities	35	30
Regulation and Metering Stations	50	35
Odorising Stations	35	20
SCADA	15	0

3.1.5 Estimated and Committed Capital Expenditure

The Code[26] provides that Reference Tariffs may be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement period provided that such investment is reasonably expected to pass the prudency tests set out in the Code[27] which are that New Facilities Investment must:

- not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted industry practice, and achieve the lowest sustainable cost of delivering Services; and
- meet one of the following conditions:
  - the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or
  - the New Facility has system-wide benefits that justify a higher Reference tariff; or
  - the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

[26] Section 8.20.
[27] Section 8.16.

The amount of New Facilities Investment that is expected to occur within the Access Arrangement Period is based on the amount of capital expenditure required by NT Gas to provide Services to Users during this period. New Facilities Investment for the ABDP system comprises three components:

- 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.

The amounts estimated for New Facilities Investment are set out in the table below[28].

Estimated Capital Expenditure ($'m)[29]

Year Ending 30 June	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Expansion Capital	0	0	0	0	0	0	0	0	0	0
Replacement Capital	0.02	2.51	0.07	0	0.07	2.39	0.08	0	0.08	0
Non-System Capital	0.36	0.49	1.55	0.52	0.53	0.82	0.56	0.57	0.58	0.60
Total Capital Expenditure	**0.38**	**3.00**	**1.62**	**0.52**	**0.60**	**3.21**	**0.63**	**0.57**	**0.67**	**0.60**

It is not NT Gas's usual practice to commit to capital expenditure for significant periods in advance of that expenditure. Rather a capital budget is prepared annually which is subject to both management and board approval.

All of the New Facilities Investment represent best estimates arrived at on a reasonable basis and is required to maintain either the safety and integrity of the ABDP or its Services in satisfaction of the Code requirements.

28 These estimates reflect the assumed levels and timing of replacement of components. Although NT Gas regards these assumptions as appropriate to base its capital expenditure estimates on at the present time, NT Gas cannot and does not make any representation or warranty as to the accuracy of the estimates presented.

29 In dollars of the day.

3.2 Rate of Return

3.2.1 WACC Approach

NT Gas has adopted a weighted average cost of capital (WACC) approach as a guide to determining the appropriate rate of return for the ABDP.

3.2.2 Variables

The Final Decision requires that the WACC calculation be based on the following parameter values:

WACC parameters – ***Final Decision***

Real risk-free rate (rr_f) %	3.26
Expected inflation rate (f) %	2.19
Nominal risk-free rate (r_f) %	5.52
Cost of debt margin (DM) %	1.54
Cost of debt (r_d) %	7.07
Real cost of debt (rr_d) %	4.78
Market risk premium (r_m-r_f) %	6.0
Debt funding (D/V) %	60
Usage of imputation credits (γ) %	50
Corporate tax rate (T) %	30
Effective tax rate (T_e)	5.24
Asset beta (β_a)	0.50
Debt beta (β_d)	0.15
Equity beta (β_e)[(a)]	1.0

Note: (a) The Commission uses the Monkhouse formula as follows:
$\beta_e = \beta_a + (\beta_a - \beta_d)(1 - r_d/(1+r_d)T_e).D/E.$

When these parameter values are applied, the resulting values of the components of WACC and WACC itself (as determined in the Final Decision) are:

	Per cent
Nominal cost of equity $r_e = r_f + \beta_e (r_m - r_f)$	11.67
Nominal pre-tax cost of debt (r_d)	7.07
Nominal vanilla WACC $W_n = r_e.E/V + r_d .D/V$	8.91
Post-tax nominal WACC $W = r_e [(1-T_e)/(1-T_e(1-\gamma))].E/V + r_d (1-T).D/V$	7.51
Post-tax real WACC $W_r = (1+W)/(1+f) - 1$	5.21
Pre-tax nominal WACC $W_t = r_e /(1-T_e(1-\gamma)).E/V + r_d .D/V$	9.03

	Per cent
Pre-tax real WACC	6.75 (b)
Pre-tax nominal WACC – cash flows (W_{trci})	9.09 (b)
Implied tax wedge = W_{trci} - W_n	0.18

Note: (b) Obtained from the Commission's cash flow analysis

3.3 Total Revenue

The Code[30] provides that one of three calculation methodologies can be used to determine the Total Revenue. NT Gas has adopted the "cost of service" approach whereby Total Revenue is equal to the cost of providing all Services (some of which may be the forecast of such costs), and with this cost to be calculated on the basis of:

- a Rate of Return on the value of the Capital Base; plus
- depreciation of the Capital Base; plus
- the operating, maintenance and other non-capital costs incurred in providing all Services provided by the pipeline.

Based on the value of the ICB, WACC value, depreciation and non-capital costs specified in the Final Decision for 2001/02 the Total Revenue for the year ending 30 June 2002 is $45.08 million made up as follows:

Year Ending 30 June	**2002**
Regulatory Asset Base	**228.5**
Depreciation	14.1
Total Operating Costs	6.8
Other	24.2
TOTAL REVENUE	45.1
Throughput (PJ)	16.4

NOTE: Disaggregated financial information used to derive the cost of service is confidential as identified in the Final Decision. This information has been provided to and reviewed by the Commission as part of its Final Decision.

30 Section 8.4.

3.4 Allocation Of Total Revenue

The Total Revenue determined in Section 3.3 is allocated into each of the pricing zones as detailed in the following table.

Total Revenue ($m)[31] – Zonal Basis

Year Ending 30 June	**2002**
Zone 1:	
Depreciation	6.5
Total Operating Costs	3.0
Other	11.1
Total Revenue - Zone 1	**20.6**
Throughput (PJ) – Zone 1	16.4
Zone 2:	
Depreciation	4.5
Total Operating Costs	2.0
Other	7.6
Total Revenue – Zone 2	**14.1**
Throughput (PJ) – Zone 2	16.0
Zone 3:	
Depreciation	3.2
Total Operating Costs	1.8
Other	5.5
Total Revenue – Zone 3	**10.4**
Throughput (PJ) – Zone 3	14.0

The additional tariff component referred to in the Final Decision[32] is included in Other costs.

For each year of the Access Arrangement Period the allocation of:

- total operating costs to each pricing zone is generally on the basis of length of pipeline operated in each zone (discussed in Section 4.4); and

[31] In dollars of the day. Note that due to rounding differences some columns in the table may not appear to sum precisely.

[32] Amendment FDA 3.6

- return on capital (ie EBIT) and return of capital (ie depreciation) to each pricing zone is on the basis of the proportion that the ORC of the pipeline assets in each pricing zone bears to the total ABDP ORC, where the ORC of the assets in each pricing zone has been determined to be as follows:.

	ORC ($m, 2001)
Zone 1	171.6
Zone 2	118.6
Zone 3	83.5
Total	373.7

3.5 Reference Tariff for Pricing Zones

Having allocated the Total Revenue to each pricing zone, the Reference Tariff for each zone for the year ending 30 June 2002 can be determined on a per gigajoule basis by dividing the estimated throughput into the required revenue for that year.

Reference Tariff ($/GJ) for Year Ending 30 June, 2002[33]

Zone 1	1.26
Zone 2	0.89
Zone 3	0.74
TOTAL	2.88

The formula by which Reference Tariffs will be calculated for years after 2002 is set out in the Access Arrangement and accords with the requirements of the Final Decision (Amendment FDA3.8). The Commission, in the Final Decision, forecasts tariffs for the years after 2002 as:

Forecast Zonal Reference Tariffs ($/GJ)

Year ending June 30	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Zone 1	1.26	1.27	1.28	1.29	1.30	0.97	0.97	0.98	0.99
Zone 2	0.89	0.90	0.90	0.91	0.92	0.68	0.69	0.69	0.70
Zone 3	0.74	0.75	0.75	0.76	0.76	0.57	0.57	0.57	0.58
Total	**2.90**	**2.92**	**2.94**	**2.96**	**2.98**	**2.22**	**2.23**	**2.24**	**2.26**

[33] In dollars of the day.

which are expected to produce revenues in each year of:

Year ending 30 June	**Forecast revenue (nominal $m)**
2002	45.08
2003	45.35
2004	46.81
2005	47.12
2006	47.42
2007	47.73
2008	35.55
2009	35.78
2010	36.01
2011	36.24

4 NON-CAPITAL COSTS: OPERATIONS AND MAINTENANCE AND OVERHEADS AND MARKETING

Estimates of non-capital costs have been developed by NT Gas for the Access Arrangement Period. Pursuant to the Code[34] the forecasts of non-capital costs detailed in this section represent best estimates arrived at on a reasonable basis.

4.1 Operations and Maintenance Costs

Operation and maintenance costs are the direct costs of operating and maintaining the ABDP and are detailed in table below in the categories specified in the Code[35]. An additional category has been included which identifies the infrequent but recurring costs of intelligent pigging activities on the pipeline.

Operational activities undertaken include the continuous monitoring, operation and control of the:
- pipeline,
- pipeline right of way,
- pipeline facilities; and
- compressor station.

Maintenance activities undertaken include the maintenance of the :
- pipeline,
- pipeline facilities,
- right-of-way maintenance,
- Pipeline SCADA and communications system; and
- regulation, metering and gas measurement equipment.

Other activities related to the operation and maintenance activities include pipeline integrity management, pipeline facility upgrading and training for emergency response.

There has been no allowance made for system use gas in the operations and maintenance costs, since system use gas will be provided by the user[36]. There has been no allowance made in the operating and maintenance costs for contingency.

4.2 Overheads and Marketing Costs

Overhead costs (ie Administration and General) include expenditure relating to:
- insurances,
- directors fees,
- regulatory activities,
- compliance,
- personnel and training,

[34] Section 8.2(e).
[35] Attachment A of the Code.
[36] Refer to Schedule 2, Part 1 of the Access Arrangement.

- legal,
- accounting,
- taxation; and
- Government levies.

Sales and Marketing costs include expenditure relating to:
- advertising and promotion of gas transportation services,
- investigation and feasibility studies for potential gas consuming projects,
- commercial negotiations relating to gas transportation services, and
- general contract management and administration activities.

Total Non-capital Costs 2002-2011

Year Ending June 30 ($'000)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Operations & maintenance	5,347	5,644	7,193	6,633	6,570	7,609	6,957	7,944	7,418	7,710
Administration & general	1,351	1,383	1,145	1,449	1,483	1,518	1,554	1,591	1,628	1,667
Sales & Marketing	138	141	145	148	152	156	160	164	168	172
Total Non-capital Costs	**6,836**	**7,168**	**8,753**	**8,230**	**8,205**	**9,283**	**8,670**	**9,699**	**9,214**	**9,549**

4.3 Fixed versus Variable costs

For the throughputs estimated for the ABDP during the Access Arrangement Period, operating and maintenance costs will not vary significantly with throughput during this period.

4.4 Cost Allocation

All of the operating and maintenance costs are direct costs to NT Gas and will be fully allocated to the Reference Service specified in the ABDP Access Arrangement on the basis of length of pipeline operated in each of the three ABDP pricing zones. Length of pipeline is the fundamental driver of operating and maintaining a pipeline.

Administration and general costs are allocated to each of the ABDP pricing zones on the same basis as operating and maintenance costs, since these costs are driven primarily by operating and maintenance costs.

Sales and marketing costs are allocated on the basis of the quantity of gas delivered out of the pipeline from delivery points within each of the ABDP pricing zones. Such an allocation process assumes that sales and marketing costs within each of the ADBP's pricing zones are strongly influenced by quantity of gas delivered within those zones.

The allocation of non-capital costs into each pricing zone is detailed in the following table.

Total Operating Cost ABDP[37] (Zonal Basis)

Year Ending June 30 ($'000)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Zone 1	3,049	3,197	3,904	3,671	3,660	4,141	3,867	4,326	4,110	4,259
Zone 2	2,025	2,124	2,593	2,438	2,431	2,750	2,569	2,874	2,730	2,829
Zone 3	1,761	1,847	2,255	2,121	2,114	2,392	2,234	2,499	2,374	2,460
Total Non-capital Costs	**6,836**	**7,168**	**8,753**	**8,230**	**8,205**	**9,283**	**8,670**	**9,699**	**9,214**	**9,549**

There is no regulated/unregulated differentiation of Users on the ABDP.

[37] In dollars of the day. Note that due to rounding differences some columns in the table may not appear to sum precisely.

5 SYSTEM CAPACITY AND VOLUME ASSUMPTIONS

5.1 General

This section provides details relating to the technical specifications and throughput assumptions of the ABDP. For background information on the history of the ABDP refer to Section 1.2.

The reason the ABDP was built was to connect gas production facilities at the Palm Valley and Mereenie gas fields to the Channel Island Power Station. The pipeline system includes a branch supply line from the Mereenie production facilities together with small lateral pipelines at Tennant Creek and Katherine.

The ABDP has a maximum allowable operating pressure of 9.6Mpa. The main pipeline is:

- 355.6mm (14") outside diameter (OD) for the southern 1110km connecting Palm Valley to Mataranka;
- 323.9mm (12") OD for the 391km section between Mataranka and the Darwin City Gate; and
- 219.1mm (8") OD for the 12km section between the Darwin City Gate and Channel Island.

The Mereenie branch supply line is 273.1mm (10") outside diameter and 116km in length. This pipeline has a maximum allowable operating pressure of 10.2Mpa.

The pipeline steel specification is API 5L Grade X60 (in accordance with API Specification for Line Pipe, API Spec 5L). Pipeline wall thickness design has been determined in accordance with the Pipeline Code AS2885. A brief summary of technical details associated with the ABDP is as follows:

Applicable Code	AS2885	
Maximum allowable operating pressure (MAOP)	9,650kPa(g) (class 600) mainline; and 10,150kPa(g) (class 600) - Mereenie spur	
Steel grade	API 5L X60	
Diameter and wall thickness	355.6mm 323.9mm 219.1mm 273.1	5.8mm (Palm Valley - Mataranka); 5.25mm (Mataranka -Darwin City Gate); 7.92mm (DCG – Channel Is); and 4.78mm (Mereenie Spur)
Length	1513km	
External coating	Extruded high density polyethylene (Shaw - Yellow Jacket)	
Internal coating	None	

Depth of cover	1200mm in roads and most locations; 5000mm for directional drills; 2000mm under rails and 1200mm under railway reserves; and 900mm in private property

- 2 remotely monitored inlet stations at Palm Valley and Mereenie gas fields.
- 11 remotely monitored delivery stations at 2 at Tennant Creek, 2 at Katherine, Edith River, Pine Creek, Daly Waters, Mataranka, Cosmo Howley, Channel Island and the Darwin City Gate.
- 11 intermediate scraper stations consisting of remotely actuated mainline valves and pig launch and receive facilities.
- 17 remotely actuated valves co-located at the delivery stations and scraper stations and 13 manually actuated mainline valves.
- 1 gas odourisation plant located at Tylers Pass (interconnection of the Mereenie spur line and the main pipeline).
- 1 compressor station located at Warrego north of Tennant Creek. The compressor is a Solar 2 stage centrifugal unit driven by a Solar Saturn 1.2 MW gas turbine. The compressor station was commissioned in October 1996.
- 1 pipeline control centre in Palmerston which uses a SCADA system to remotely control and continuously monitor the pipeline.
- Cathodic protection system.
- 4 regional bases – Katherine, Tennant Creek, Alice Springs, and Daly Waters.
- Head office and operations base at Palmerston.

5.2 Map of ABDP and Pipe Specification

A map of the ABDP Route is attached as Attachment 3, together with a schematic of the three pricing zones for the pipeline. It is to be noted that only those pipelines noted as being included in Pipeline Licence 4 in attachment 3 are included in the ABDP system for the purposes of this Access Arrangement Information. For information purposes, all gas transmission infrastructure connected into the ABDP has been included in the map in Attachment 3.

A detailed description of the boundaries of the three pricing zones is in the following table.

Zone	Boundaries
1	Outlet of Palm Valley and Mereenie production facilities to the inlet of the Warrego compressor station.
2	Inlet of the Warrego compressor station to the inlet of the Mataranka scraper station (end of 350mm pipeline and commencement of the 300mm pipeline).
3	Inlet of the Mataranka scraper station to the outlet of the Channel Island meter station.

Pipe sizes, lengths and delivery capability is set out in the tables below:

Pipeline Section	**Diameter (mm outside)**	**Length (km)**
Palm Valley to Mataranka	355.6	1110
Mataranka to Darwin City Gate	323.9	391
Darwin City Gate to Channel Island	219.1	12
Mereenie to Tylers Pass Supply Lateral	273.1	116
Tennant Creek Lateral	114.3	24
Katherine Lateral	114.3	5

Zone	**Length of Pipeline (km)**
1	730
2	521
3	407

Maximum Delivery Capability[38]	
Free-flow conditions	44 TJ/d (approx)
With compressor operating	54 TJ/d (approx)

5.3 Average Daily and Peak Demands

The table below sets out the gate station load profiles for the financial year 30 June, 2002.

Off-take/Parameter	**2002**
Channel Island:	
Total Annual Volume (TJ)	11159
Average Daily Flow Rate (GJ)	30572
Peak Day Flow Rate (GJ)	45070
Minimum Delivery Pressure (kPa)(a)	2400
Cosmo Howley Off-take:	
Total Annual Volume (TJ)	24
Average Daily Flow Rate (GJ)	65
Peak Day Flow Rate (GJ)	1299
Minimum Delivery Pressure (kPa)(a)	2800

38 Delivery capability of a pipeline is strongly related (among other technical considerations) to heating value of the gas being transported. For the purposes of this Access Arrangement Information a heating value of 40MJ/m^3 has been assumed.

39 Estimated figure as total throughput is derived by the addition of individual customer meters which are not read daily.

40 Estimated figure as total throughput is derived by the addition of individual customer meters which are not read daily.

Off-take/Parameter	2002
Pine Creek:	
Total Annual Volume (TJ)	1935
Average Daily Flow Rate (GJ)	5302
Peak Day Flow Rate (GJ)	6675
Minimum Delivery Pressure (kPa)(a)	2700
Katherine:	
Total Annual Volume (TJ)	318
Average Daily Flow Rate (GJ)	872
Peak Day Flow Rate (GJ)	4830
Minimum Delivery Pressure (kPa)(a)	2600
Katherine 2:	
Total Annual Volume (TJ)	13
Average Daily Flow Rate (GJ)	53
Peak Day Flow Rate (GJ)	150
Minimum Delivery Pressure (kPa)(a)	400
Tennant Creek:	
Total Annual Volume (TJ)	506
Average Daily Flow Rate (GJ)	1386
Peak Day Flow Rate (GJ)	2434
Minimum Delivery Pressure (kPa)(a)	2600
Tennant Creek 2:	
Total Annual Volume (TJ)	16
Average Daily Flow Rate (GJ)	80
Peak Day Flow Rate (GJ)	223
Minimum Delivery Pressure (kPa)(a)	400
Elliott Off-take:	
Total Annual Volume (TJ)	19
Average Daily Flow Rate (GJ)	51
Peak Day Flow Rate (GJ)	965
Minimum Delivery Pressure (kPa)(a)	2400
Daly Waters Off-take:	
Total Annual Volume (TJ)	2038
Average Daily Flow Rate (GJ)	5584
Peak Day Flow Rate (GJ)	7147
Minimum Delivery Pressure (kPa)(a)	2800
Edith River Off-take:	
Total Annual Volume (TJ)	69
Average Daily Flow Rate (GJ)	188
Peak Day Flow Rate (GJ)	3300
Minimum Delivery Pressure (kPa)(a)	4350

Off-take/Parameter	2002
Mataranka Off-take:	
Total Annual Volume (TJ)	26
Average Daily Flow Rate (GJ)	72
Peak Day Flow Rate (GJ)	132
Minimum Delivery Pressure (kPa)(a)	250
Darwin City Gate Off-take:	
Total Annual Volume (TJ)	8
Average Daily Flow Rate (GJ)	23
Peak Day Flow Rate[39] (GJ)	34
Minimum Delivery Pressure (kPa)(a)	900
Palm Valley Interconnect Off-take:	
Total Annual Volume (TJ)	738
Average Daily Flow Rate (GJ)	2022
Peak Day Flow Rate[40] (GJ)	6996
Minimum Delivery Pressure (kPa)(a)	

5.4 Estimated Load Across Each Pricing Zone[41]

Estimated average daily, peak and total pipeline load in each of the three pricing zones of the ABDP for years ending 30 June 2003 – 2007 are set out below. These estimates are an amalgamation of forecasts provided by Users.

Load and Volume[42]	2003	2004	2005	2006	2007
ZONE 1					
Average Daily Load (TJ/d)	1.3	1.3	1.2	1.2	1.2
Peak Load (TJ/D)	2.3	2.2	2.6	2.6	2.7
Annual Volume (PJ)	0.5	0.5	0.4	0.4	0.6
ZONE 2					
Average Daily Load (TJ/d)	5.5	5.4	5.5	5.5	5.5
Peak Load (TJ/D)	6.8	6.8	6.8	6.8	6.8
Annual Volume (PJ)	2.0	2.0	2.0	2.0	2.0
ZONE 3					
Average Daily Load (TJ/d)	39.5	39.4	39.5	39.5	39.5
Peak Load (TJ/D)	52.6	47.9	49.1	50.7	52.3
Annual Volume (PJ)	14.4	14.4	14.4	14.4	14.4

41 The estimated throughput and load profiles are based on experience in comparable projects and assumptions as to the timing and level of penetration of natural gas. Although NT Gas regards these assumptions as appropriate to base the projection on at the present time, NT Gas cannot and does not make any representation or warranty as to the accuracy of the projections.

42 Note that load and volume in each zone reflects gas delivered out of the pipeline in that zone – not total pipeline throughput in the zone.

Load and Volume[42]	**2003**	**2004**	**2005**	**2006**	**2007**
TOTAL ABDP					
Average Daily Load (TJ/d)	46.3	46.2	46.0	46.0	46.0
Peak Load (TJ/D)[43]	53.1	51.3	53.2	54.7	56.4
Annual Volume (PJ)	16.9	16.9	16.8	16.8	16.8

The table below contrasts financial year 2002 total pipeline throughput as derived from User forecasts as submitted for the 1999 Access Arrangement Information and actual throughput. As is demonstrated by the table, historically actual pipeline peak day loads have generally been higher than User forecasts.

It is NT Gas's expectation that the actual peak day deliveries over the Access Arrangement Period will be higher than that forecast by Users, and further, that the ABDP will at times be running at capacity to fulfil existing User contracts.

Load and Volume	**2002 Forecast (1999 Submission)**	**2002 Actual**
Average Daily Load (TJ/D)	44.0	46.3
Peak Load (TJ/D)	53.7	64.9
Annual Volume (PJ)	16.4	16.9

[43] The addition of the peak loads estimated for each zone exceeds the peak load estimated for the pipeline which reflects that peak loads in each of the zones do not occur simultaneously.

5.5 System Load Profile by Month

The table below sets out the ABDP load profile by month in terms of percentage of total annual pipeline throughput delivered in each month for financial year 2002. This load profile in expected to be indicative of the load profile of each of the three ABDP pricing zones.

Month	**% of total Annual Load**
July	6.7
August	7.2
September	7.6
October	8.8
November	8.7
December	8.7
January	9.5
February	8.6
March	9.4
April	8.8
May	8.7
June	7.2
Total	**100**

5.6 Numbers of Users on the ABDP as at June 2002

There is currently a total of three Users on the ABDP. The number of Users in each of the pricing zones is detailed in the following table.

Zone	**Number of Users**
1	2
2	1
3	3

6 EFFICIENT COSTS AND PERFORMANCE MEASURES FOR PIPELINES

6.1 Key Performance Indicators

6.1.1 Total Operating Cost Comparisons

Two benchmarks are considered in the pipeline industry as providing a broad expectation of the level of operating costs:

1. Opex as a percentage of pipeline capital (replacement) cost.
2. Opex/km of pipeline length.

As for all partial indicator type benchmarks there are a number of factors which will affect these such as, the terrain through which the pipelines operate, the level of compression and a range of other particular circumstances that drive both construction cost and operating cost. There is therefore a considerable variability between pipelines reflecting these factors.

In the Final Decision on the Moomba-Adelaide Pipeline the Commission noted that in referring to the first measure (percentage of capital costs – with ORC as a proxy for capital cost), "Typically this ranges from 2 percent for an uncompressed pipeline to 5 percent for a fully compressed pipeline".

The Commission also considered the second measure ($opex per km) in the Moomba-Adelaide Pipeline Final Decision.

The attached table compares the values for the ABDP for both measures against the major Australian pipelines, based on the opex values approved by regulators under Final Decisions, or Draft Decisions where there is no Final Decision.

On both the measures the opex for the ABDP is well within the range of variables accepted by regulators.

Opex as a percentage of ORC
The ABDP ratio of 1.7 percent is considered reasonable by the Commission. It is consistent with the expected ratio for a partially compressed pipeline, and is in line with pipelines of similar size, terrain and levels of compression.

Opex per km
The Commission concludes that this ratio, at $3.7k per km for the ABDP, compares favourably with other Australian transmission pipelines.

Benchmarking O&M Costs for Australian Pipelines
(real 2001 dollars)

	EAPL MSP		Epic MAP		GasNet		GGT		Epic DBNGP		NT Gas ADP	
	% ORC	$000 /km	% ORC	$000/ km	% ORC	$000/ km	% ORC	$000/ km	% ORC	$000/ km	% ORC	$000/ km
2000							2.3%	7.5	1.7%	16.8		
2001			2.4%	14.4			2.2%	7.2	1.6%	16.4		
2002			2.3%	13.8			2.2%	7.2	1.8%	18.5	1.7%	3.7
2003	2.2%	11.3	2.3%	13.9	3.6%	14.6	2.2%	7.2	1.8%	18.2	1.7%	3.7
2004	2.2%	11.5	2.3%	13.8	2.5%	9.9	2.4%	7.8	1.8%	17.8	1.7%	3.7
2005	2.2%	11.4	2.3%	13.8	2.4%	9.6					2.0%	4.4
2006	2.2%	11.4			2.5%	10.1					1.7%	3.7
2007	2.2%	11.4			2.5%	10.1						
2008	2.2%	11.4										

SOURCES:

EAPL Moomba- Sydney:
Revised background information: 12/8/02
Information requested in ACCC letter dated 27/5/02
EAPL Access Arrangement 1999

Epic Moomba-Adelaide:
ACCC Access Arrangement for MAP
ACCC Final Decision
Epic Energy SA: Schedules for Access Arrangement for Moomba to Adelaide Pipeline
System (29 June 2001)

GasNet:
ACCC Draft Decision (14 August 2002)
GPU GasNet Pty Ltd - Application for Revision to Access Arrangement: Annexure 1
GHD Technical Life Analysis of GasNet's Transmission System
GPU GasNet Public Report: 2001 Comparative Performance Benchmarking for the Natural Gas Pipeline Industry

Goldfields Gas Pipeline:
OffGAR Draft Decision (10 April 2001)
GGT: Access Arrangement Information (15 December 1999)

Epic Dampier-Bunbury:
OffGAR Draft Decision (21 June 2001)
Epic Energy: Proposed Access Arrangement Information (28 July 2000)

NT Gas Amadeus Basin-Darwin:
NT Gas: Access Arrangement Information (25 June 1999)
ACCC Draft Decision (2 May 2001)

ATTACHMENT 1

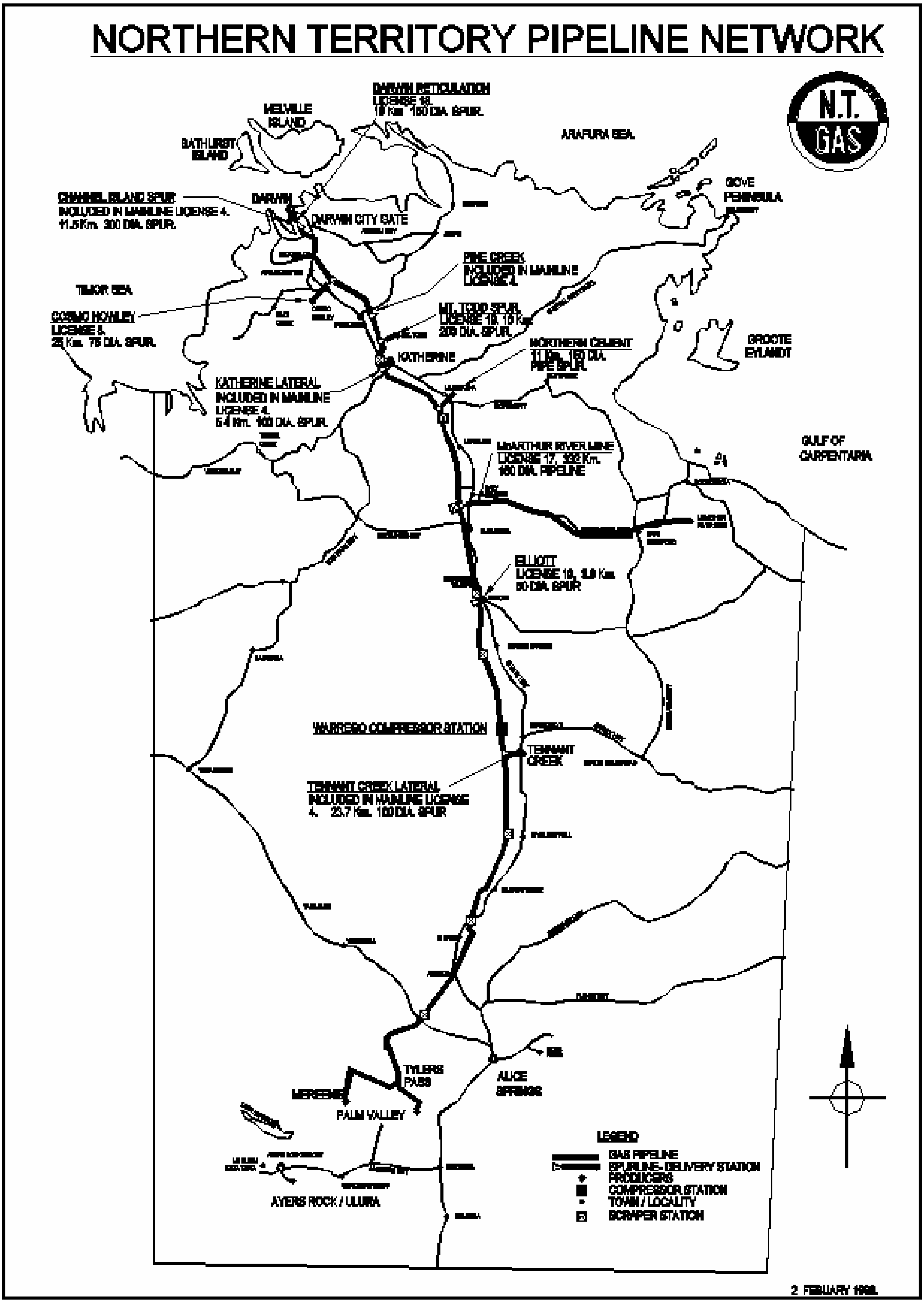
CATEGORIES OF INFORMATION TO BE DISCLOSED AS PART OF THE ACCESS ARRANGEMENT INFORMATION

Category in Access Code	Reference in the Access Arrangement Information
Category 1: Information regarding Access & Pricing Principles	
Tariff determination methodology.	2.2
Cost Allocation approach.	2.5
Incentive structure.	2.6
Category 2: Information regarding Capital Costs	
Asset values for each pricing zone, service or category of asset.	3.1
Information as to asset valuation methodologies – historical cost or asset valuation.	3.1
Assumptions on life of asset for depreciation.	3.1.4
Depreciation.	3.1.3
Accumulated depreciation.	3.1
Committed capital works and capital investment.	3.1.5
Description of nature and justification for planned capital investment.	3.1.5
Rates of return – on equity and on debt.	3.2.2
Capital Structure – debt/equity split assumed.	3.2.2
Equity returns assumed – variables used in derivation.	3.2.2
Debt costs assumed – variables used in Derivation.	3.2.2
Category 3: Information regarding Operations and Maintenance Costs	
Fixed versus variable costs.	4.3
Cost allocation between zones, services or categories of asset & between regulated and unregulated.	4.4
Wages & Salaries – by pricing zone, service or asset category.	4.1
Cost of services by other including rental equipment.	4.1
Gas used in operations – unaccounted for gas to be separated from compressor fuel.	4.1
Materials and supply.	4.1
Property Taxes.	4.1
Category 4: Information on Overheads & Marketing Costs	
Total service provider costs at corporate level	4.2
Allocation of costs between regulated and unregulated segments.	4.4
Allocation of costs between particular zones, services or categories of asset.	4.4

Category in Access Code	Reference in the Access Arrangement Information
Category 5: Information regarding System Capacity & Volume assumptions	
Description of system capabilities	
Map of piping system – pipe sizes, distances and maximum delivery capability.	5.1, 5.2, Attachment 2
Average daily and peak demand at "city gates" defined by volume and pressure.	5.3
Annual volume across each pricing zone, service or category of asset.	5.4
System load profile by month in each pricing zone, service or category of asset.	5.5
Total Number of customers in each pricing zone, service or category of asset.	5.6
Category 6: Information regarding Key Performance Indicators	
Service provider's KPIs for each pricing zone, service or category of asset.	6.1

ATTACHMENT 2:

MAP OF AMADEUS BASIN TO DARWIN PIPELINE ROUTE AND SCHEMATIC DETAILING ZONE BOUNDARIES


NORTHERN TERRITORY PIPELINE NETWORK
N.T. GAS
DARWIN RETICULATION
MELVILLE ISLAND
BATHURST ISLAND
ARAFURA SEA
CHANNEL ISLAND SPUR
INCLUDED IN MAINLINE LICENSE 4.
11.5 Km. 300 DIA. SPUR.
DARWIN
DARWIN CITY GATE
GOVE PENINSULA
PINE CREEK
INCLUDED IN MAINLINE LICENSE 4.
TIMOR SEA
COSMO HOWLEY
LICENSE 5.
25 Km. 75 DIA. SPUR.
MT. TODD SPUR
LICENSE 19. 15 Km
200 DIA. SPUR.
NORTHERN CEMENT
11 Km. 150 DIA.
PIPE SPUR.
GROOTE EYLANDT
KATHERINE
KATHERINE LATERAL
INCLUDED IN MAINLINE
LICENSE 4.
5.4 Km. 100 DIA. SPUR.
McARTHUR RIVER MINE
LICENSE 17, 332 Km.
150 DIA. PIPELINE
GULF OF CARPENTARIA
ELLIOTT
LICENSE 19, 1.9 Km.
50 DIA. SPUR
WARREGO COMPRESSOR STATION
TENNANT CREEK
TENNANT CREEK LATERAL
INCLUDED IN MAINLINE LICENSE
4. 23.7 Km. 100 DIA. SPUR
TYLERS PASS
ALICE SPRINGS
MEREENIE
PALM VALLEY
AYERS ROCK / ULURU
LEGEND
GAS PIPELINE
SPURLINE- DELIVERY STATION
PRODUCERS
COMPRESSOR STATION
TOWN / LOCALITY
SCRAPER STATION

AMADEUS BASIN TO DARWIN PIPELINE
ZONE BOUNDARIES