OFFICE OF GAS ACCESS REGULATION

OffGAR WESTERN AUSTRALIA

DRAFT DECISION:

ACCESS ARRANGEMENT

TUBRIDGI PIPELINE SYSTEM

Submitted by

Tubridgi Parties

SAGASCO South East Inc
Boral Energy Petroleum Pty Ltd (now Origin Energy Petroleum Pty Ltd)
Boral Energy Amadeus NL (now Origin Energy Amadeus NL)
Pan Pacific Petroleum NL
Tubridgi Petroleum Pty Ltd

Part B

Supporting Information

INDEPENDENT GAS PIPELINES ACCESS REGULATOR

WESTERN AUSTRALIA

7 August 2000

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GLOSSARY

Terms used in the Draft Decision have the meanings ascribed to them under the *Gas Pipelines Access (Western Australia) Act 1998* or the Access Arrangement for the Tubridgi Pipeline System. Readers should refer to these documents for definitions of specific terms. In order to assist understanding, summary definitions of several terms used widely in this Draft Decision are provided below.

Access Arrangement	A statement of policies and the basic terms and conditions that apply to third party access to a covered pipeline.
Access Arrangement Information	Additional and/or supplemental information pertaining to the Access Arrangement.
Access Request	A request for access to a Service made in accordance with the Access Arrangement.
Arbitrator	The Office of the Western Australian Gas Disputes Arbitrator established under section 62 of the *Gas Pipelines Access (WA) Act 1998*.
Bare Transfers	A transfer by a User of all or part of its contracted capacity on a pipeline not requiring the consent of the Service Provider and as it does not involve a change in the contractual arrangements between the User and the Service Provider.
Capacity	The potential of a pipeline, as currently configured and operated in a prudent manner consistent with good pipeline industry practice, to deliver a particular Service between a Receipt Point and a Delivery Point at a point in time.
Capacity Management Policy	A policy that is required to be in the Access Arrangement indicating whether the Covered Pipeline is to be administered as a Contract Carriage Pipeline or a Market Carriage Pipeline.
Capital Base	Has the meaning given to “Capital Base” in section 8.4 of the Code.
Capital Expenditure	Expenditure on a Covered Pipeline and associated regulated assets to be incorporated into the Capital Base of the pipeline.
Code	The *National Third Party Access Code for Natural Gas Pipeline Systems.*
Consent Transfers	A transfer by a User of all or part of its contracted capacity on a pipeline where the transfer is subject to the consent of the Service Provider.

Contract Carriage	A system of managing third party access whereby the Service Provider normally manages its ability to provide Services primarily by requiring Users to use no more than the quantity of service specified in a contract (defined in detail in the Code).
Contracted Capacity	The nominal quantity of gas transportation to be undertaken under a service agreement between a User and the Service Provider.
Covered Pipeline	The whole or particular part of a pipeline which is regulated under the Code.
Delivery Point	A point of a pipeline at which the custody of gas is transferred from a Service Provider to a User.
Depreciated Actual Cost	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.
Depreciated Optimised Replacement Cost	Is the depreciated minimum cost of replacing or replicating the service potential embodied in a pipeline with modern equipment and in the most efficient way practicable, from an engineering perspective, given the service requirements, the age and condition of the existing assets and replacement in the normal course of business.
Depreciation Schedule	The Depreciation Schedule is the set of depreciation schedules that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of determining a Reference Tariff.
Extensions/ Expansions Policy	A policy that is required to be in the Access Arrangement setting out a method for determining whether extension or expansion to the Covered Pipeline is or is not to be treated as part of the Covered Pipeline for the purposes of the Code.
Fixed Period	The period during which a Fixed Principle may not be changed.
Fixed Principle	An element of the Reference Tariff Policy that can not be changed without the agreement of the Service Provider.
Haulage Contract	An agreement entered into between a Pipeline Service Provider and a User under which the Pipeline Service Provider agrees to provide a Reference Service on terms and conditions as set out in an Access Arrangement.
Incentive Mechanism	Incentive Mechanism has the meaning given to "Incentive Mechanism" in sections 8.44 and 10.8 of the Code.
Initial Capital Base	Initial Capital Base means the Capital Base at the commencement of the Access Arrangement Period.

Market Carriage	A system of managing third party access whereby the Service Provider does not normally manage its ability to provide Services primarily by requiring Users to use no more than the quantity of Service specified in a contract (defined in more detail in the Code).
Market Variable Element	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.
Minister	Is the Western Australian Minister for Energy unless otherwise indicated.
National Gas Pipelines Access Agreement	A national agreement to introduce a national gas pipelines access regime endorsed by CoAG and signed by all Australian Heads of State on 7 November 1997.
New Facilities Investment	An increase in the Capital Base of the pipeline after the commencement of a new Access Arrangement Period to reflect additional capital costs incurred in modifying or adding to existing assets for the purpose of providing services.
Non-Capital Costs	Non-Capital Costs has the meaning given to **"**Non-Capital Costs**"** in section 8.4 of the Code, which at the date of the publication of this decision was: "...the operating, maintenance and other Non-Capital Costs incurred in providing all Services provided by the Covered Pipeline".
Non-Reference Service	A service other than a Reference Service.
Operating Expenditure	The Non-Capital Costs incurred by a Service Provider in operating, maintaining and delivering services.
Optimised Replacement Cost	Is the minimum cost of replacing or replicating the service potential of an asset with modern equipment in the most efficient way practicable, from an engineering perspective, given specified service requirements.
Prospective User	A person who seeks or who is reasonably likely to seek to enter into a Service Agreement with a Service Provider and includes a User who seeks or may seek to enter into a Service Agreement for an additional Service.
Queuing Policy	A policy that is required to be included in an Access Arrangement which defines the priority that a Prospective User has over another Prospective User to negotiate for specific Capacity.

Rate of Return	Rate of Return has the meaning given to "Rate of Return" in section 8.4 of the Code, which at the date of the publication of this decision was: "...a return (*Rate of Return*) on the value of the capital assets that form the Covered Pipeline (*Capital Base*)."
Receipt Point	A point of a pipeline at which the custody of gas is transferred to the Service Provider.
Reference Service	A Service that is specified as a Reference Service in an Access Arrangement.
Reference Tariff	A tariff specified in an Access Arrangement as corresponding to a Reference Service.
Regulator	The Independent Gas Pipelines Access Regulator in Western Australia established under section 27 of the *Gas Pipelines Access (WA) Act 1998.*
Residual Value	The value of the Capital Base at the end of the Access Arrangement Period after allowing for Capital Expenditure, Redundant Capital and Depreciation during the Period.
Revisions Commencement Date	A date upon which the next revisions to the Access Arrangement are intended to commence.
Revisions Submissions Date	A date upon which the Service Provider must submit revisions to the Access Arrangement.
Ring Fencing	A requirement on a Service Provider to establish arrangements to segregate or "ring fence" its business of providing Services using a covered pipeline from other business activities.
Scheme Participant	Scheme Participant means the State of Western Australia as defined in section 11 of the *Gas Pipelines Access (Western Australia) Act 1998*.
Service	A Reference Service or Non-Reference Service relating to the transportation of gas by a Service Provider, and in the case of a Service Agreement means the particular Reference Service or Non-Reference Service the subject of that Service Agreement.
Service Agreement	An agreement between a Service Provider and a User for the provision of a Service.
Services Policy	An Access Arrangement must include a policy on the Services to be offered, including a description of one or more Services. A Services Policy commits a Service Provider to making available Reference Services to Prospective Users, and for the provision of Non-Reference Services to Prospective Users.

Service Provider	In relation to a pipeline or proposed pipeline, means the person who is, or who is to be, the owner or operator of the whole or any part of the pipeline or proposed pipeline.
Structural Element	Any principle or methodology that is used in the calculation of a Reference Tariff where that principle or methodology is not a Market Variable Element and has been structured for Reference Tariff making purposes over a longer period than a single Access Arrangement Period.
Total Revenue	Total Revenue has the meaning given in section 8.2 of the Code, which says it is the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement period.
Trading Policy	A policy that is required to be in the Access Arrangement for a Contract Carriage Pipeline, as required by section 3.9 of the Code, regarding trading capacity and the rights of a User to trade its rights to obtain a Service to another person.
User	A person who has a current Service Agreement or an entitlement to a Service as a result of arbitration under Section 6 of the Code.

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
CAPM	Capital Asset Pricing Model
CMS	CMS Gas Transmission of Australia Pty Ltd
CoAG	Council of Australian Governments
CPI	Consumer Price Index
DAC	Depreciated Actual Cost
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DORC	Depreciated Optimised Replacement Cost
GJ	Gigajoules (10^9 joules)
GST	Goods and Services Tax
IPARC	Independent Pricing and Access Regulatory Commission (ACT)
IPART	Independent Pricing And Regulatory Tribunal (New South Wales)
IRR	Internal Rate of Return
kPa	Kilopascals
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MAOP	Maximum Allowable Operating Pressure
MDQ	Maximum Daily Quantity
NCC	National Competition Council
NPV	Net Present Value
O*ff*GAR	Office of Gas Access Regulation
ORG	Office of the Regulator General (Victoria)
PJ	Petajoules (10^{15} joules)
TLPG	Tempered Liquefied Petroleum Gas
TJ	Terajoules (10^{12} joules)
WACC	Weighted Average Cost of Capital

1 INTRODUCTION

On 21 October 1999 a proposed Access Arrangement for the Tubridgi Pipeline System was submitted by the joint owners of the pipeline system to the Independent Gas Pipelines Access Regulator in Western Australia (the Regulator) for approval under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code).

The Tubridgi Pipeline System consists of two pipelines. These are the Tubridgi Pipeline (Licence Number WA: PL 16), which is a 150 mm diameter pipeline constructed in 1991 and the Griffin Pipeline (Licence Number WAPL19), which is a 250mm pipeline that became operational in 1994. Both are 87 km long and run along the same easement, from the Tubridgi gas field to Compression Station 2 of the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

At the time the Access Arrangement was submitted, the joint owners of the pipeline (the Tubridgi Parties) comprised:

SAGASCO South East Inc
Boral Energy Petroleum Pty Ltd
Boral Energy Amadeus NL
Pan Pacific Petroleum NL
Tubridgi Petroleum Pty Ltd

Since submission of the Access Arrangement, the names of Boral Energy Petroleum Pty Ltd and Boral Energy Amadeus NL have been altered to Origin Energy Petroleum Pty Ltd and Origin Energy Amadeus NL, respectively. The latter company names are used throughout this Draft Decision.

This Part B of the Draft Decision details the analysis and provides background and supporting information on which the Draft Decision is based. The Draft Decision is outlined in Part A.

In preparing the Draft Decision, the Regulator assessed the Access Arrangement on the basis of three broad criteria:

i. whether the Access Arrangement meets the requirements of sections 3.1 to 3.20 of the Code that explicitly state the matters that must be addressed in an Access Arrangement;

ii. whether the proposed Reference Tariffs are consistent with the objectives of section 8 of the Code and were determined in accordance with the principles set out in section 8; and

iii. whether the inclusion and substance of matters included in the Access Arrangement, but not required by sections 3 or 8 of the Code, are reasonable having regard to the interests of the Service Provider, Prospective Users, Users, the public interest and other considerations provided for in section 2.24 of the Code.

The supporting information set out in this part is generally organised such that matters relevant to assessment of the Access Arrangement are addressed in the same sequence as in the Code. There are, however, several areas of overlap and cross-reference between different parts of the Code that would cause excessive repetition if this sequence were rigorously adhered to. The supporting information is thus structured as follows.

- Background information on the regulatory framework within which an Access Arrangement is assessed.
- The process for assessment of an Access Arrangement, and in particular the Access Arrangement for the Tubridgi Pipeline System.
- Assessment of matters addressed by the Access Arrangement other than which relate to tariffs, fees and charges (non-tariff matters).
- Assessment of Reference Tariffs proposed by the Tubridgi Parties for the Tubridgi Pipeline System.
- Assessment of fees and charges, other than tariffs, proposed by the Tubridgi Parties for the for the Tubridgi Pipeline System.
- Responses to any additional matters raised in public submissions.

2 REGULATORY FRAMEWORK

2.1 THE WESTERN AUSTRALIAN GAS INDUSTRY

This section provides some background information relating to the Western Australian gas industry.

Gas Production

Western Australia and its immediate offshore areas possess significant resources of natural gas, holding more than three quarters of the identified natural gas reserves within Australia. Natural gas accounts for 39 per cent of the State's identified energy resources, which will last over 100 years at the current level of production. There are five sedimentary basins in this area, with two of these basins currently producing natural gas for sale – the Northern Perth Basin and the Carnarvon Basin. There are nine producing fields currently supplying natural gas to the domestic market, indicated as follows.

Carnarvon Basin	Northern Perth Basin
North West Shelf	Dongara
Harriet Gas Gathering	Woodada
Tubridgi Onshore Gas	Beharra Springs
Griffin Oil/Gas	
Roller/Skate Oil/Gas	
East Spar	

In 1998/99 a total of 780 PJ of natural gas was estimated by the Office of Energy to have been produced from the two major basins, with the majority originating from the Carnarvon Basin. The natural gas produced from these areas is either sold to the domestic Western Australian market or exported in the form of liquefied natural gas (LNG).

Gas Pipeline Infrastructure

There are currently 3 major onshore natural gas transmission pipelines in Western Australia – the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the Goldfields Gas Pipeline, and the Parmelia Pipeline.

The Epic Energy owned DBNGP transports gas from the North West Shelf to residential, business and industrial customers in the Geraldton, Perth, Mandurah and Bunbury areas. The pipeline system comprises a main pipeline and laterals, with a total length of 1845 km and current maximum delivery capacity of about 600 TJ/day to current delivery points.

The Goldfields Gas Pipeline runs 1380km from the North West of Western Australia to the Northern and Eastern Goldfield areas and is owned by the Goldfields Gas Transmission Pty

Ltd, a private consortium comprising Southern Cross Pipelines and Duke Energy. The Goldfields Gas Pipeline has a current capacity of around 90 TJ/d, and can reach 164 TJ/d when fully compressed.

The Parmelia Pipeline, previously the Western Australian Natural Gas (WANG) pipeline, was commissioned in 1971 and transports gas from various fields in the North Perth basin to a number of major industrial customers in the South West. The pipeline is owned by CMS Energy Corporation and is operated by an Australian division named CMS Gas Transmission of Australia (CMS). The pipeline is capable of delivering up to 120 TJ/day, including transport of gas from Dongara, the North West Shelf (via an interconnection with the DBNGP), the Beharra Springs field and the Woodada field.

The Tubridgi Pipeline System comprises two juxtaposed pipelines of approximately 87 km in length – the Tubridgi Pipeline (WA PL16) and the Griffin Pipeline (WA PL19). Both pipelines are located in the same easement and extend from the Tubridgi Gas Plant, 25 km south of Onslow, to Compressor Station No.2 on the Dampier to Bunbury Natural Gas Pipeline. The pipeline system is owned by the Tubridgi Joint Venture. The joint venture partners are:

SAGASCO South East Inc
Origin Energy Petroleum Pty Ltd
Origin Energy Amadeus NL
Pan Pacific Petroleum NL
Tubridgi Petroleum Pty Ltd

The joint venture partners are referred to collectively in this report as the Tubridgi Parties.

Operating functions for the pipeline are performed by the Origin Energy companies.

Details of the two pipelines are as follows.

	Tubridgi Pipeline	**Griffin Pipeline**
Year of construction	1991	1993
Pipeline diameter	150 mm	250 mm
Maximum operating pressure	12.8 MPa	12 MPa
Nominal capacity	30 TJ/day	90 TJ/day

Neither pipeline is equipped with compression.

The pipelines are used principally to transport gas to the DBNGP. The Tubridgi Pipeline transports gas sourced from the Tubridgi Gas Field via the Tubridgi Gas Plant. The Griffin Pipeline transports gas sourced from the Griffin Gas Field, via the Griffin Gas Plant, and from Thevenard Island. The pipelines may potentially be used to back-haul gas from the DBNGP for the purposes of supplying gas to a power station at the town of Onslow.

2.2 NATIONAL GAS ACCESS REGIME

In February 1994, the Council of Australian Governments (CoAG) agreed to progress a number of reforms to promote free and fair trade in natural gas in Australia. These reforms included the development of a uniform national framework for the regulation of third-party access to natural gas transmission pipelines.

On 7 November 1997, CoAG endorsed a national regulatory regime for natural gas pipelines in Australia, including distribution pipelines. This occurred through the signing of the Gas Pipelines Access Agreement (the Agreement), which amongst other things records each jurisdiction's commitment in relation to implementing the national regime and maintaining the integrity of the Agreement.

As provided for under the Agreement, the legislation put in place in Western Australia has an essentially identical effect to the *Gas Pipelines Access (South Australia) Act 1997*.

2.3 LEGISLATION

In Western Australia the *Gas Pipelines Access (WA) Act 1998* has given effect to the *National Gas Pipelines Access Law* comprising the law itself (Schedule 1 of the Act) and the *National Gas Pipelines Access Code for Natural Gas Pipeline Systems* (the Code), which is Schedule 2 of the Act.

Prior to the commencement of the *Western Australian Act*, third party access to pipelines within Western Australia was regulated by either the *Petroleum Pipelines Act 1969* or the *Petroleum (Submerged Lands) Act 1982* for transmission pipelines or by specific legislation for particular transmission and distribution pipeline systems.

For the DBNGP, third party access was regulated by the *Dampier to Bunbury Pipeline Act 1997* and the *Dampier to Bunbury Pipeline Regulations 1998*, and for the Goldfields Gas Pipeline third party access was regulated by the *Goldfields Gas Pipeline Agreement Act 1994*. Third party access to the AlintaGas distribution systems was regulated by the *Gas Corporation Act 1994* and the *Gas Distribution Regulations 1995*.

The existing access regimes for the DBNGP, the Goldfields Gas Pipeline and the AlintaGas distribution systems were deemed to comply with the Code until 31 December 1999.

2.4 THE WESTERN AUSTRALIAN ACCESS REGIME

The Access Regime established by the *Gas Pipelines Access (WA) Act 1998* comprises the following four elements.

i. The Act itself that gives effect to the *Gas Pipelines Access (WA) Law*.

ii. Schedule 1, that provides the legal framework for the operation of the Access Regime.

iii. Schedule 2, which is the Code and that contains the detailed access principles of the Access Regime.

iv. Schedule 3, that contains consequential amendments to certain Acts.

The Gas Pipelines Access (WA) Act 1998

The Western Australian Act makes provision for the following matters.

- Extension of the coverage of the Code to include liquefied petroleum gas (LPG) and tempered LPG (TLPG) (section 8).

- Application of the *Gas Pipelines Access Law* as a law in Western Australia (section 9).

- Provision for the making of regulations and the application of those regulations in Western Australia (sections 10, 12, 13, and 14).

- Definition of the various bodies exercising functions under the Code in Western Australia (section 11).

- Conferral of functions and powers on the various Commonwealth and State Code bodies and the Federal Court (sections 15 to 21).

- Application of the Commonwealth *Administrative Decisions (Judicial Review) Act 1972* to certain decisions made under the Code (section 22).

- Exemption from State taxes from the transfer of assets or liabilities when complying with ring-fencing requirements of the Code. The Western Australian Act also contains a clarification that is not contained in the legislation of other jurisdictions that the Regulator may include tax liabilities when assessing the administrative costs of complying with ring-fencing obligations of the Code (section 23).

- Establishment of the Western Australian Independent Gas Pipelines Access Regulator (the Regulator) who will act as the Regulator for the purposes of the Law and the Code for distribution and transmission pipelines in Western Australia (sections 26 to 48).

  Features of the Regulator's role are as follows.

  – The Regulator is entirely independent of direction or control by the Crown or any Minister or officer of the Crown in exercising its functions under the Law, Code or Agreement.

  – The Regulator is appointed by the Governor for terms of 3 to 5 years and can only be removed from office by both Houses of Parliament.

  – The Minister sets the annual expenditure limit for the Regulator but otherwise the Regulator is free to expend the monies within that limit and subject to the prudent financial controls in the *Financial Administration and Audit Act 1985* (including the audit by the Auditor General).

  – The Minister may issue directions to the Regulator on general policies to be followed in matters of administration and financial administration, but such directions cannot constrain the Regulator with respect the performance of any function conferred on the Regulator under the Access Regime or the Agreement. Such Directions are to be tabled in both Houses of Parliament, and must be Gazetted and a copy provided to the Code Registrar.

- Where the Regulator, in assessing a proposed Access Arrangement, is required by the Code to take the public interest into account the Regulator is required to, amongst other things, take into account the fixing of appropriate charges as a means of extending effective competition in the supply of natural gas to residential and small business customers.

- The Regulator is required to notify the Minister of any conflict of interest with his/her duties.

- Funding of functions under the Act is through fees determined under the *Gas Pipelines Access (WA) (Funding) Regulations 1999* that became effective on 14 January 2000.

- The effectiveness of the operation of the Regulator for transmission pipelines will be reviewed when a significant gas transmission pipeline crosses Western Australia's border or after the 7 November 2002 (whichever is the earlier).

- Establishment of the Western Australian Gas Review Board to act as the appeals body for certain purposes under the Law and the Code. The Gas Review Board consists of a presiding member to be chosen from a panel of legal practitioners by the Attorney–General, and two experts chosen from a panel of experts by the presiding member (sections 49 to 60).

- Establishment of the Western Australian Gas Disputes Arbitrator for the purposes of the Law and the Code and of hearing of disputes under the *Gas Referee Regulations 1995* (sections 61 to 85).

  Features of the Gas Disputes Arbitrator's role are as follows.

  - The Arbitrator is entirely independent of direction or control by the Crown or any Minister or officer of the Crown.

  - The Arbitrator is appointed by the Governor for terms of 3 to 5 years and can only be removed from office by both Houses of Parliament.

  - The Minister may issue directions to the Arbitrator on general policies to be followed in matters of administration and financial administration, but such directions cannot constrain the Arbitrator with respect to the performance of any function conferred on it under the Access Regime or the Agreement, or other access regimes such as the transitional Dampier to Natural Gas Pipeline regime. Such Directions are to be tabled in both Houses of Parliament, and must be Gazetted and copies provided to any person on request.

- Making of regulations including the setting of fees and charges for the Regulator, the Board and the Arbitrator (section 87).

- Transitional provisions (sections 89 to 97).

Schedule 1 of the Gas Pipelines Access (WA) Act 1998

Schedule 1 of the Act contains the provisions necessary to give the Code legal effect including provisions, as follows.

- Definition of the Code and providing for its amendment (sections 5 and 6 of Schedule 1, when read in conjunction with the definition of scheme participants in section 3 and other definitions in section 2).

- Establishment of a procedure for classifying pipelines as transmission or distribution pipelines and for determining which jurisdiction a cross-border distribution pipeline is most closely connected with (sections 9 to 11). This is done for the purposes of defining whose Code bodies will have jurisdiction under the Code.

- Prohibition of certain persons preventing or hindering access to Code pipelines (section 13).

- Establishment of procedures for arbitrating access disputes under the Code (sections 14 to 31).

- Provision for legal proceedings to be brought to the Supreme Court in relation to breaches of certain provisions of the Law and the Code (sections 32 to 37).

- Establishment of a right of administrative review of certain decisions made under the Code (sections 38 to 39).

- Placing of an obligation on producers of natural gas who offer to supply delivered gas to also offer to supply gas at the exit flange of the producer's processing plant (section 40).

- General provisions relating to the Regulator's ability to obtain information and documents (sections 41 to 43).

The Law is applied as a law in Western Australia by the *Gas Pipelines Access (WA) Act 1998*, as well as in each other state and territory by their respective Acts.

Schedule 2 of the Gas Pipelines Access (WA) Act 1998

Schedule 2 of the Act comprises the Code. This is identical to the access code appearing in Annex D to the Agreement and in Schedule 2 to the South Australian Act and the respective Acts of other states and territories. The Code is applied as a law in Western Australia and establishes, amongst other things, the following.

- A mechanism by which natural gas pipelines become subject to the Code (called "Covered Pipelines" or "Code Pipelines") (section 1). Schedule A to the Code lists the pipelines that were initially covered by the Code in Western Australia.

- A requirement that the Service Provider (ie owner/operator) of a Covered Pipeline establish with the relevant Regulator an up-front Access Arrangement setting out the terms on which access will be given to certain services provided by the Covered Pipeline, including the Reference Tariffs for such services (section 2). The content of an Access

Arrangement (section 3) and the principles, which must be applied in setting the Reference Tariffs (section 8), are also specified.

- A right to arbitration where a Service Provider of a Covered Pipeline and a Prospective User cannot agree on the terms of access to a service. The arbitrator is obliged in any such arbitration to apply the terms of the Access Arrangement established with the relevant Regulator (section 6).

- Obligations on Service Providers of Covered Pipelines to ring fence their operations (section 4).

- Obligations on Service Providers and Users to disclose information (section 5).

- A requirement that the Service Provider of a Covered Pipeline not enter into contracts with associates without first obtaining the approval of the relevant Regulator (section 7).

3 ASSESSMENT PROCESS

3.1 OVERVIEW

Where a pipeline is covered by the Code there is a requirement for a pipeline Service Provider to establish an Access Arrangement. The Regulator may approve an Access Arrangement only if it satisfies the minimum requirements set out in section 3 of the Code. The Regulator must not refuse to approve an Access Arrangement solely for the reason that the proposed Access Arrangement does not address a matter that section 3 does not require an Access Arrangement to address. Subject to this limitation, the Regulator has a broad discretion to refuse to accept an Access Arrangement.

An Access Arrangement submitted to the Regulator for approval must be accompanied by specified Access Arrangement Information. The purpose of the Access Arrangement Information is to enable Users and Prospective Users to understand the derivation of the elements of the proposed Access Arrangement and form an opinion as to the compliance of the Access Arrangement with the Code.

The process by which an Access Arrangement is assessed and approved can be summarised as follows.

- The Service Provider submits a proposed Access Arrangement, together with the Access Arrangement Information, to the Regulator.

- The Regulator may require the Service Provider to amend and resubmit the Access Arrangement Information.

- The Regulator publishes a public notice and seeks submissions on the application.

- The Regulator considers the submissions, issues a Draft Decision and then, after considering any submissions received on the draft, makes a Final Decision which either:

  - approves the proposed Access Arrangement; or

  - does not approve the proposed Access Arrangement and states the revisions to the Access Arrangement which would be required before the Regulator would approve it; or approves a revised Access Arrangement submitted by the Service Provider which incorporates amendments specified by the Regulator in its Draft Decision.

- If the Regulator does not approve the Access Arrangement, the Service Provider may propose an amended Access Arrangement, which incorporates the revisions required by the Relevant Regulator.

- If the Regulator does not approve the Access Arrangement and the Service Provider does not propose an amended Access Arrangement, the Relevant Regulator can impose an Access Arrangement.

The *Gas Pipeline Access (WA) Law* provides a mechanism for the review of a decision by the Regulator to impose an Access Arrangement.

The particular components of the assessment process for the Access Arrangement submitted for the Tubridgi Pipeline System are described below.

3.2 SUBMISSION OF THE ACCESS ARRANGEMENT AND SUPPORTING INFORMATION

Documentation submitted to the Regulator by the Tubridgi Parties on 21 October 1999 was as follows.

- Tubridgi Pipeline System Access Arrangement, incorporating:
  - Map of Pipeline Route (Annexure A)
  - General Terms and Conditions (Annexure B); and
  - Tariff Schedule for the Tubridgi Pipeline System (Annexure C).
- Tubridgi Pipeline System Access Arrangement Information, incorporating:
  - The Weighted Average Cost of Capital (WACC) for the Tubridgi Pipeline System (WA PL16 & PL 19) (Appendix A); and
  - Depreciated Optimised Replacement Cost (DORC) Valuation for the Tubridgi Pipeline System (WA PL16 & PL 19) (Appendix B).

Copies of these documents are available from the Office of Gas Access Regulation or may be downloaded from the O*ff*GAR web site (www.offgar.wa.gov.au).

3.3 FIRST–ROUND PUBLIC CONSULTATION

O*ff*GAR undertook the following actions to provide public notification of receipt of the Access Arrangement and invite submissions from interested parties.

- Forwarding of notices to interested parties (5 November 1999).
- Placing of the notice calling for submissions on the O*ff*GAR web site (5 November 1999).
- Placing of advertisements calling for public submissions in *The West Australian* and the *Weekend Australian* (10 November 1999).

An issues paper was prepared by O*ff*GAR and forwarded to interested parties on 17 November 1999. The issues paper was also made available from the O*ff*GAR office and the O*ff*GAR web site. A closing date for receipt of public submissions was set at 4pm 10 December 1999.

Documentation submitted by the Tubridgi Parties for the proposed Access Arrangement was made available from the O*ff*GAR office and on the O*ff*GAR web site.

Submissions were received from the following organisations.

- AlintaGas's trading division ("AlintaGas Trading").

- BHP Petroleum Pty Ltd.
- CMS Gas Transmission Australia.
- Office of Energy.
- Western Power.

The contents of submissions are summarised and addressed in Chapters 4 to 6 of this Draft Decision, relating the issues raised to specific matters addressed by the Access Arrangement.

3.4 DRAFT DECISION

This document comprises the Regulator's Draft Decision in respect of the Access Arrangement submitted by the Tubridgi Parties. The Draft Decision is a result of an assessment by the Regulator of compliance of the Access Arrangement with requirements of the Code. The Draft Decision states the amendments (or the nature of amendments) that are required to be made to the Access Arrangement before the Regulator will approve it.

The Draft Decision provides an opportunity for the Service Provider to make any amendments to the Access Arrangement deemed necessary by the Regulator prior to a final decision on acceptance or rejection of the Access Arrangement. Publication of the Draft Decision also provides an opportunity for public comment on the Regulator's assessment of the Access Arrangement.

3.5 SECOND–ROUND PUBLIC CONSULTATION

Public submissions are invited on the Draft Decision. In accordance with the requirements of Section 2.14 of the Code, a copy of this document has been provided to all persons that made a submission as part of the first round of public consultation. Copies of the document are available in hard-copy form from O*ff*GAR and the document is also available for downloading from the O*ff*GAR web site.

The closing date for receipt of submissions on the Draft Decision is 8 September 2000.

3.6 FINAL DECISION

In accordance with section 2.16 of the Code, the Regulator will, after consideration of submissions on the Draft Decision, issue a Final Decision which:

(a) approves the Access Arrangement; or

(b) does not approve the Access Arrangement and states the amendments (or nature of the amendments) which would have to be made to the Access Arrangement in order for the Relevant Regulator to approve it and the date by which a revised Access Arrangement must be resubmitted by the Service Provider; or

(c) approves a revised Access Arrangement submitted by the Service Provider which the Relevant Regulator is satisfied incorporates the amendments specified by the Relevant Regulator in its draft decision.

The Regulator shall issue a Final Decision by 21 November 2000, unless the Regulator extends the period for issue of a Final Decision under provisions of section 2.22 of the Code.

In accordance with requirements of section 2.17 of the Code, a copy of the Regulator's Final Decision will be provided to all persons that made a submission in respect of the Access Arrangement or Draft Decision, and copies will be made publicly available in hard-copy form and via O*ff*GAR's web site.

3.7 ADDITIONAL AMENDMENTS TO THE ACCESS ARRANGEMENT

If the Regulator does not approve the Access Arrangement and the Service Provider submits a revised Access Arrangement by the date specified by the Regulator under section 2.16(b) of the Code, which the Regulator is satisfied incorporates the amendments specified by the Relevant Regulator in its final decision, the Regulator will issue a Final Decision that approves the revised Access Arrangement.

If the Regulator does not approve the Access Arrangement and the Service Provider does not submit a revised Access Arrangement by the date specified by the Regulator under section 2.16(b) of the Code or submits a revised Access Arrangement which the Regulator is not satisfied incorporates the amendments specified by the Regulator in its Final Decision, the Regulator may draft and approve its own Access Arrangement. This would be undertaken in accordance with requirements for public consultation specified in section 2.23 of the Code.

4 NON-TARIFF MATTERS

4.1 INTRODUCTION

An Access Arrangement must, as a minimum, include the elements described in section 3 of the Code. Section 3 establishes the following requirements.

- Services Policy (sections 3.1 and 3.2).

  An Access Arrangement must include a policy on the Services to be offered. The Services Policy must:

  - include a description of one or more Services which are to be offered;
  - where reasonable and practical, allow Prospective Users to obtain a Service that includes only those elements that the User wishes to be included in the Service; and
  - where reasonable and practical, allow Prospective Users to obtain a separate tariff in regard to a separate element of a Service.

- Reference Tariff (sections 3.3 to 3.5).

  An Access Arrangement must contain one or more Reference Tariffs. A Reference Tariff operates as a benchmark tariff for a specific Service, in effect giving the User a right of access to the specific Service at the Reference Tariff, and giving the Service Provider the right to levy the Reference Tariff for that Service.

- Terms and Conditions (section 3.6).

  An Access Arrangement must include the terms and conditions on which the Service Provider will supply each Reference Service.

- Capacity Management Policy (sections 3.7 and 3.8).

  An Access Arrangement must state whether the covered pipeline is a Contract Carriage Pipeline or a Market Carriage Pipeline.

- Trading Policy (sections 3.9 to 3.11).

  An Access Arrangement for a Contract Carriage Pipeline must include a policy on the trading of capacity.

- Queuing Policy (sections 3.12 to 3.15).

  An Access Arrangement must include a policy for defining the priority that Prospective Users have to negotiate for specific Capacity (a Queuing Policy).

- Extensions/Expansions Policy (section 3.16).

  An Access Arrangement must include a policy setting out a method for determining whether an extension or expansion to the covered pipeline/distribution system is or is not to be treated as part of the covered pipeline for the purposes of the Code.

- Review Date (sections 3.17 to 3.20).

  An Access Arrangement must include a date on or by which revisions to the Access Arrangement must be submitted and a date on which the revised Access Arrangement is intended to commence.

With the exception of the requirements for Reference Tariffs, the compliance of the Access Arrangement with the above requirements of the Code is addressed below. Reference Tariffs are addressed separately in section 5 of this report.

4.2 SERVICES POLICY

4.2.1 Access Code Requirements

Section 3.1 of the Code requires that an Access Arrangement include a policy on the Service or Services to be offered (a Services Policy). Section 3.2 of the Code requires that the Services Policy comply with the following principles.

(a) The Access Arrangement must include a description of one or more Services that the Service Provider will make available to Users or Prospective Users, including:

  (i) one or more Services that are likely to be sought by a significant part of the market; and

  (ii) any Service or Services which in the Relevant Regulator's opinion should be included in the Services Policy.

(b) To the extent practicable and reasonable, a User or Prospective User must be able to obtain a Service that includes only those elements that the User or Prospective User wishes to be included in the Service.

(c) To the extent practicable and reasonable, a Service Provider must provide a separate Tariff for an element of a Service if this is requested by a User or Prospective User.

4.2.2 Access Arrangement Proposal

A Services Policy is provided in clause 2 of the Access Arrangement, comprising an offer by the Tubridgi Parties to make available to Users and Prospective Users a Reference Service (the Haulage Reference Service) and Non-Reference Services (Negotiated Services). The Services Policy also provides, to the extent practical and reasonable, for a User or Prospective User to obtain a service that includes only those elements that the User or Prospective User wishes to be included in the service, and for a separate tariff to be provided for an element of a pipeline service if requested to do so by a User or Prospective User.

The Haulage Reference Service is described in clauses 2 and 4 of the Access Arrangement and in the General Terms and Conditions. Clause 2 of the Access Arrangement indicates the Haulage Reference Service to comprise:

- accepting a quantity of gas at a transmission receipt point;
- the physical forward haulage of gas from that transmission receipt point to a transmission delivery point;
- the delivery of an equivalent quantity of gas at a transmission delivery point;
- the provision and maintenance of metering equipment at transmission delivery points;
- readings of metering equipment at transmission receipt points once each pipeline day, with readings provided to pipeline Users on a monthly basis.

The service is a continuous service (subject to interruption as provided for under clause 13.1 of the General Terms and Conditions), with a minimum contract period of one year. The quantity of gas able to be transported under a Haulage Reference Service is defined as a Maximum Daily Quantity (MDQ) (clause 3 of the General Terms and Conditions).

4.2.3 Submissions from Interested Parties

Back Haul Service

- Western Power

  The Access Arrangement does not allow for a back haul Non-Reference Service. In Western Power's view, prospective shippers should have an opportunity to back haul gas through either of the two pipelines, making up the Tubridgi Pipeline System, so that competitively priced gas can be brought to the Onslow area. Western Power considers that back haul should be identified as a Non Reference Service.

  Western Power also considers that, where a back haul service is provided, investigation is required on the potential impact on gas quality in respect of the Tubridgi Pipeline System. Any benefits to the Tubridgi Parties, by reducing LPG penalties on the DBNGP, should be shared with shippers in the Tubridgi Pipeline System.

- BHP Petroleum Pty Ltd

  The proposed Reference Service consists of a forward haul service. We understand that there may be a market for a back haul service. Given the small number of parties that comprise the total market, we suggest that a reasonable interpretation of the requirement in 3.2(a)(ii) of the Code that the Proposed Arrangement should include this service.

The Regulator has discretion under section 3.2(a) of the Code to require an Access Arrangement to describe a particular service in the Services Policy. Furthermore, under section 3.3(b) of the Code, the Regulator may require a Reference Tariff to be included in an Access Arrangement for any service that is likely to be sought by a significant part of the market and for which the Relevant Regulator considers a Reference Tariff should be included, in which case the service constitutes a Reference Service. It is noted, however, that while section 3.2(a)(ii) of the Code states that an Access Arrangement must include a description of any Service or Services which, in the Regulator's opinion, should be included in the Services Policy, there is no implication that a service included in the Services Policy must be a Reference Service, that is, one that must have a Reference Tariff associated with it.

The Regulator has given consideration firstly to whether a back-haul service should be described in the Services Policy, and secondly to whether a back-haul service should be included in the Access Arrangement as a Reference Service.

While there is a potential demand for a back-haul service to provide gas to Onslow, there is currently no such usage. In the current circumstances, the Regulator is of the opinion that a back-haul service cannot be considered likely to be sought by a significant part of the market and hence does not warrant inclusion in the Access Arrangement as a Reference Service. Nevertheless, a back-haul service providing gas to Onslow may potentially be important both as a significant component of gas throughput in the pipeline at a time after the forward-haul of gas from offshore fields declines, and in terms of promoting competition in supply of gas to Onslow. For this reason, the Regulator is of the opinion that the Services Policy should make explicit provision for a back-haul service, as a Non-Reference Service.

As tariffs for Non-Reference Services are negotiated between a Prospective User and the Service Provider, the possible sharing of benefits arising as a result of a back-haul arrangement that avoids LPG penalties on the DBNGP is therefore a matter of negotiation between the parties. The Code provides a dispute resolution mechanism where agreement cannot be reached.

The following amendment is required before the Access Arrangement will be approved.

Amendment 1 Clause 2 of the Access Arrangement should be amended to include a back-haul service as a Non-Reference Service.

Metering

- CMS Gas Transmission Australia

  Section 3.1.1 of the AAI provides a description of the components of the Reference Service which includes "readings of Metering Equipment at Transmission Receipt Points once each Pipeline Day, with readings provided to Pipeline Users on a monthly basis", although there is only a requirement of the Service Provider for "the provision and maintenance of Metering Equipment at Transmission Delivery Point". This seems inconsistent. Further, it is not clear to CMS what is meant by "Transmission Receipt Point" and "Transmission Delivery Point", nor how these precisely relate to the "User Receipt Point" and "User Delivery Point" meter requirements specified in GTC Sections 5 & 6. While the latter are required to "continuously and instantaneously measure the Quantity of Gas delivered" through each Point, as a point of principle, CMS suggest that the provision of daily meter readings to Users should be daily rather than monthly as specified in section 3.1.1 of the Access Arrangement Information in order for Users to have full access to information which would enable them to manage gas imbalances.

- BHP Petroleum Pty Ltd

  We note that the Pipeline User is required to provide continuous and instantaneous Metering Equipment at each Receipt Point (clause 5.1 of the General Terms and Conditions) and provide remote access to this equipment (clause 5.2 of the General Terms and Conditions). Similarly, the Service Provider is required to provide continuous and instantaneous measurement at the User Delivery Point (clause 6.1 of the General Terms and Conditions). This being the case, the proposal to provide this information with the invoice each month is restrictive as, in the absence of at least the end of Gas Day custody quantity, it restricts Pipeline

> Users' ability to deal with the gas. We submit that the Reference Service should give Pipeline Users access to this information daily and as close to the end of the Gas Day as possible. In addition the Reference Service should provide for Pipeline Users to be given remote access to the measurements and readings taken at the Delivery Point Meters.

Information provided by the Tubridgi Parties indicates that the first matter raised in the CMS submission relates to a typographical error in the Access Arrangement. The reference to transmission receipt points in the fifth bullet point of clause 2.2 of the Access Arrangement should be a reference to transmission delivery points. The Regulator notes that this error will be corrected prior to approval of the Access Arrangement.

The Tubridgi Parties also provided information to clarify the distinction between transmission receipt points and User receipt points and between transmission delivery points and User delivery points. Transmission receipt points and transmission delivery points are all of the delivery points and receipt points on the pipeline system. They include those receipt points and delivery points that currently exist, and any new receipt points and delivery points that are constructed in the future. In contrast, User receipt points and User delivery points are the subset of transmission receipt points and transmission delivery points that a particular User is entitled to use in respect of its Reference Service. The Regulator considers that this distinction is adequately explained in definitions provided in clause 10 of the Access Arrangement.

Information provided by the Tubridgi Parties indicates that Users would not require daily meter readings for balancing purposes due to the existence of apportionment arrangements. Apportionment arrangements comprise agreements between pipeline Users, the Tubridgi Parties and the owner or operator of the DBNGP to apportion gas delivered through each transmission receipt point and each transmission delivery point amongst the pipeline Users. By virtue of apportionment agreements, gas delivered from the Tubridgi Pipeline System to the DBNGP will be apportioned amongst Users according to the quantities delivered by each User into the Tubridgi Pipeline System. Any difference between the total quantity of gas delivered from the Tubridgi Pipeline System to the DBNGP and the sum of all quantities of gas delivered into the Tubridgi Pipeline System would be made up by the Tubridgi Parties as system use gas. As a consequence of these arrangements, any individual User cannot have a gas imbalance.

Notwithstanding the apportionment agreements for the Tubridgi Pipeline System and the consequent absence of requirements for Users to manage gas balances in the Tubridgi Pipeline System, the metered or deemed deliveries of gas from the Tubridgi Pipeline for a particular User may be of relevance to that User for the purposes of reconciliation of gas quantities. For this reason, the Regulator considers that the Access Arrangement should provide for metering information to be available to Users on a daily basis.

The following amendment is required before the Access Arrangement will be approved.

Amendment 2 Clause 2.2 of the Access Arrangement and clause 6.2 of the General Terms and Conditions should be amended to incorporate, in the definition of the Haulage Reference Service, the provision of metering information to Users on a daily basis.

Subject to this amendment to the Access Arrangement, the Regulator does not consider it reasonable for the Tubridgi Parties to be required as part of a Reference Service to provide

Users with remote access to the measurements and readings taken at the delivery point meters, where "remote access" is taken to mean direct reading of delivery point meters by Users. However, it is noted that there is nothing to prevent a User negotiating with the Tubridgi Parties for the provision of this service as a Non-Reference Service.

4.2.4 Additional Considerations of the Regulator

Multiple Receipt Points and Delivery Points

The Regulator was concerned with ambiguity in the definition of the Haulage Reference Service in respect of numbers of receipt points and delivery points corresponding to each service agreement between a User and the Tubridgi Parties. The first two bullet points of clause 2.2 of the Access Arrangement imply that a service agreement may only accommodate a single receipt point and a single delivery point. Provisions of clause 4.1 of the Access Arrangement imply that a service agreement may provide for multiple receipt points and delivery points. Given the current use of the Tubridgi Pipeline System as a supply lateral to the DBNGP, with only a single delivery point, multiple receipt points and delivery points may not be required by Users. Notwithstanding this, the Access Arrangement should be clarified in respect of whether a single service agreement for the Haulage Reference Service may provide for multiple receipt points and delivery points in a single service agreement.

The following amendment is required before the Access Arrangement will be approved.

Amendment 3 Clause 2 of the Access Arrangement should be amended to clarify whether the Haulage Reference Service provides for multiple receipt points and delivery points in a single service agreement.

Pre-conditions to Pipeline Services

Clause 4.3 of the Access Arrangement establishes pre-conditions that a Prospective User who requires a pipeline service is required to satisfy before the Tubridgi Parties are required to provide that pipeline service, or to enter into an agreement to provide that pipeline service. Part (g) of this clause sets a one of these pre-conditions to be:

(if required by the Tubridgi Parties) the Prospective Pipeline User must execute a document setting out or incorporating the terms and conditions on which the Tubridgi Parties are to provide the Prospective Pipeline User with the Pipeline Service.

The Regulator is of the view that as the Tubridgi Parties are obliged to provide the Reference Service in accordance with the terms and conditions set out in the Access Arrangement, that this pre-condition should be limited in its application to the provision of Non-Reference Services.

The following amendment is required before the Access Arrangement will be approved.

Amendment 4

Clause 4.3(g) of the Access Arrangement should be amended to read "(if the pipeline service is a Non-Reference Service, and if required by the Tubridgi Parties) the prospective pipeline user must execute a document setting out or incorporating the terms and conditions on which the Tubridgi Parties are to provide the prospective pipeline user with the pipeline service."

Clause 4.3 of the Access Arrangement also requires that an apportionment agreement entered into by the prospective pipeline user as a pre-condition to obtaining a service must include apportionment arrangements between the prospective pipeline user and other pipeline users, together with the Tubridgi Parties and the owner or operator of the DBNGP to apportion gas delivered through each transmission receipt point and each transmission delivery point amongst the prospective pipeline user and other pipeline users.

The Regulator sees no reason for the owner or operator of the DBNGP to be a party to an apportionment agreement and therefore considers that the reference to the owner or operator of the DBNGP in clause 4.3 should be deleted.

The following amendment is required before the Access Arrangement will be approved.

Amendment 5

Clause 4.3 of the Access Arrangement should be amended to delete reference to the owner or operator of the DBNGP in relation to the requirements for a prospective pipeline user to enter into apportionment arrangements.

4.3 GENERAL TERMS AND CONDITIONS

4.3.1 Access Code Requirements

Section 3.6 of the Code requires that an Access Arrangement include the terms and conditions on which the Service Provider will supply each Reference Service. The terms and conditions included must, in the Regulator's opinion, be reasonable.

4.3.2 Access Arrangement Proposal

The Tubridgi Parties have provided General Terms and Conditions in a single document as Annexure B of the Access Arrangement.

4.3.3 Submissions from Interested Parties

The General Terms and Conditions address several matters that relate to specific requirements of sections 3.1 to 3.20 of the Code. Submissions from interested parties on the General Terms and Conditions, but which relate to these matters, are dealt with in other sections of this Draft Decision. Other matters raised in submissions are addressed below.

Delivery Quantities and Service Provider Indemnity (Clause 2.2 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  Clause 2.2 of the General Terms and Conditions which deals with Delivery Quantities appears to give the Service Provider indemnity from causing any User imbalance as well as permitting the User to be charged for imbalance even if it was somehow caused by the Service Provider. This seems unreasonable and appears to require clarification.

Clause 2.2 of the General Terms and Conditions does not relate to quantity imbalances. Rather, clause 2.2 gives the Tubridgi Parties the authority to put gas through the transmission delivery points. The Tubridgi Parties have indicated to the Regulator that the intention of clause 2.2 is to authorise the Tubridgi Parties to deliver whatever gas is taken, and to prevent pipeline Users from arguing that gas was delivered to its customers without the User's authority. The Regulator is of the opinion that this clause is generally reasonable, although ambiguous as a result of a lack of reference to any service agreement with the User. For purposes of clarity, clause 2.2 should be amended to limit the authority of the Tubridgi Parties to deliver gas through each delivery point in accordance with the service agreement with the User.

The following amendment is required before the Access Arrangement will be approved.

Amendment 6 Clause 2.2 of the General Terms and Conditions should be amended such that the clause provides authority to the Tubridgi Parties for delivery of gas through transmission delivery points on behalf of a User only in accordance with the service agreement with the User.

Maximum Daily Quantity (MDQ) Increase (Clause 4.4 of the General Terms and Conditions)

- Western Power

  MDQ is to be increased whenever the peak day quantity (PDQ) exceeds MDQ. This has the effect of automatically ratcheting MDQ upwards over the remaining period of the Access Arrangement, even though the PDQ may exceed MDQ occasionally. This is considered to be excessive; a fairer mechanism would be to increase MDQ by agreement with the User. The potential impact of this mechanism is to ramp up the charge for each GJ of MDQ, at the rate of $0.332/GJ of MDQ (Annexure C of the Access Arrangement), apparently based on the (highest) MDQ applied for each day in the month.

- CMS Gas Transmission Australia

  The Tubridgi Access Arrangement provides that if Peak Daily Quantity (PDQ) exceeds the contracted Maximum Daily Quantity (MDQ) not only is the Overrun Rate incurred as a penalty for that day (as one would expect) but the MDQ is also subsequently set at the higher PDQ commencing from the following day (GTC Section 4.4). Effectively MDQ is ratcheted up to be equal to the maximum PDQ on any day, with no apparent downward mechanism nor defined duration. The implication is that a User would potentially continue to be paying a higher than necessary reservation charge long after any short term overrun had occurred. CMS strongly opposes such a mechanism and would urge that it be removed.

- BHP Petroleum Pty Ltd

  The General Terms and Conditions relating to Capacity Management (Clause 3) and Overrun charges (Clause 4) appear to be onerous. In particular, the proposal to reset the Pipeline User's MDQ in the case where MDQ is exceeded is, particularly in the absence of any gas balancing service, unreasonably harsh.

- AlintaGas Trading

  AlintaGas Trading considers it inappropriate to unilaterally increase the MDQ if the Quantity of Gas delivered on a day exceeds the MDQ. The amount of firm capacity a User reserves should be a decision for the User. If the User has not reserved, or chooses not to reserve, sufficient firm capacity to meet its peak daily demand then the User risks being curtailed on those occasions that the MDQ is exceeded.

  Rather than having an automatic increase in MDQ, the pricing structure could be set so as to discourage a User from relying on capacity in excess of its MDQ.

In additional information provided to the Regulator, the Tubridgi Parties have indicated that the automatic increasing of MDQ when exceeded by peak daily quantity is intended to provide an incentive to Users to manage their usage of the pipeline. This approach was put forward as an alternative to the use of penalty provisions. The proposed overrun charge of $0.15/GJ is regarded by the Tubridgi Parties as relatively small at only 140 percent of the standard transportation tariff, purportedly at the low end of overrun penalties charged or proposed to be charged by other Service Providers. The Tubridgi Parties also indicated that Envestra has proposed a similar automatic increase in maximum daily quantity in certain circumstances in its Access Arrangement for the South Australian distribution system, and that similar ratchet arrangements are also used in the electricity industry to provide Users with an incentive to manage demand. Furthermore, the Tubridgi Parties indicated that there is nothing to prevent a pipeline User whose maximum daily quantity has been increased from seeking a new agreement at a lower maximum daily quantity.

In assessing whether the proposed automatic adjustments to maximum daily quantity are reasonable, the Regulator considered charging practices in current or proposed Access Arrangements for other transmission pipelines and distribution systems in Australia. Determination of transmission or distribution charges in part on the basis of maximum throughput rates is ubiquitous across for transmission pipelines and for "demand-based" tariffs on distribution systems. Maximum throughput rates may either be fixed in the contract between the User and the Service Provider, or may vary in response to realised peak throughput rates. Either charging arrangement could, in general terms, be regarded as common practice.

The proposed Access Arrangement for Envestra's South Australian distribution system provides for charges to be determined in part on the MDQ for the particular User.[1] The MDQ may be increased if the peak daily quantity exceeds the MDQ either four times in a month or eight times in a year. In view of the number of times an overrun would have to occur before the maximum daily quantity is increased, this arrangement is less onerous for Users than the arrangement proposed for the Tubridgi Pipeline System. The Regulator notes that the South

[1] Envestra Ltd, February 1999. Access Arrangement for SA Distribution System.

Australian Independent Pricing and Access Regulator considered even the arrangements proposed by Envestra for the South Australian distribution system to be overly punitive.[2]

For the Victorian transmission system and distribution systems, charges are based in part on realised maximum throughput rates for the previous year.[3] As the maximum throughputs on which charges are based may increase or decrease from year to year depending on realised use, these charging arrangements are also considered less onerous for Users than proposed for the Tubridgi Pipeline System.

In view of actual or proposed practices in other Australian transmission pipelines and distribution systems, and in view of the number of submissions on this issue for the Tubridgi Pipeline System, the Regulator is of the opinion that the proposal for automatic upwards adjustment of MDQ after overrun on a single day is unreasonably punitive.

The following amendment is required before the Access Arrangement will be approved.

> Amendment 7
>
> Clause 4.4 of the General Terms and Conditions should be amended to provide for a less punitive arrangement for adjustments to a User's maximum daily quantity than the current provisions whereby the maximum daily quantity for a User may be increased after a single day overrun by that User.

The Regulator recognises that this amendment to the General Terms and Conditions may involve alternative arrangements for variation in MDQ in response to realised peak daily quantities of Users, as well as amendments to penalty provisions for overruns.

Scheduled Meter Testing (Clause 7.2 of the General Terms and Conditions)

- Western Power

  The Tubridgi Parties state that "the party responsible for metering equipment must ensure that metering equipment is tested in accordance with good industry practice and any applicable laws". A specific time – i.e. at intervals no fewer than two months – should be specified in the Access Arrangement.

A reasonable time interval for testing and measurement of metering equipment would depend on the nature, age and condition of the equipment. Since the accuracy of metering has a direct impact on the billing procedure, it would be expected that a prudent operator would ensure that metering is accurate through undertaking tests at appropriate intervals.

"Good industry practice" may be defined by reference to other pipelines in Western Australia. Accuracy tests are carried out monthly for the Dampier to Bunbury Natural Gas Pipeline, and either monthly or two-monthly for the Goldfields Gas Pipeline. The Tubridgi

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[2] South Australian Independent Pricing and Access Regulator, April 2000. Draft Decision Access Arrangement for the South Australian Distribution Systems, p180.

[3] Victorian Gas Industry Tariff Order 1998. Charges for the transmission system are based in part on "5 day MDQ", being the sum of the five highest daily quantities of gas injected or withdrawn from the distribution system during the "peak period" 1 June to 30 September each year, and for "demand' customers on the Stratus, Westar and Multinet distribution systems on maximum hourly quantity in the previous year.

Parties have indicated to the Regulator that bi–monthly testing of meters on the Tubridgi Pipeline System is currently regarded as appropriate.

The Regulator is of the opinion that, in the absence of any demonstrable inadequacy of testing frequencies, reference to "good industry practice and applicable laws" is sufficient in specifying the frequency of testing of metering equipment.

Correction of Meter Readings (Clauses 7.8 and 7.9 of the General Terms and Conditions)

- AlintaGas Trading

  Any correction of meter readings should not be at the sole discretion of the Tubridgi Parties. If the User disagrees with the basis upon which the Tubridgi Parties makes any corrections, then the User should have recourse to appropriate dispute resolution.

  Clause 7.9 of the General Terms and Conditions states that the Tubridgi Parties will "not have to" correct meter readings that are more than one year old. This opens up the possibility for the Tubridgi Parties to correct meter readings that are more than one year old if the correction favours the Tubridgi Parties, but to not make the correction if it would favour the User. A simple modification to the clause would remove any potential for bias.

Clause 7.8 of the General Terms and Conditions provides that if the Tubridgi Parties are required by the Agreement to correct previous meter readings taken from any metering equipment, the Tubridgi Parties will make those corrections on whatever basis they consider (or the Tubridgi Operator on their behalf considers) reasonable in the circumstances. The corrections will bind the Pipeline User in the absence of manifest error. Clause 7.9 of the General Terms and Conditions provides that the Tubridgi Parties will not have to correct the readings taken from any metering equipment more than one year prior to the date of the relevant test unless the Tubridgi Parties are required to do so by law.

The Tubridgi Parties have indicated to the Regulator that the intent of clause 7.8 of the General Terms and Conditions is to allow corrections to be made on a reasonable basis. While the wording of clause 7.8 suggests that the Tubridgi Parties maintain discretion in the interpretation of "reasonable" in this context, the Tubridgi Parties have indicated a view that this clause would have the effect of binding the Tubridgi Parties in any dispute to a broader criterion of reasonableness whereby any correction must be made on a reasonable basis. Legal advice provided to the Regulator on this issue supports this view. As such, the Regulator is of the opinion that no amendment of clause 7.8 is necessary.

The Tubridgi Parties have indicated to the Regulator that the intent of clause 7.9 of the General Terms and Conditions is to limit administrative costs that may arise as a result of the review of past meter readings and that any perception of bias in the provisions of clause 7.9 was unintentional. The Regulator is of the opinion that the intention to limit administrative costs is reasonable, but that clause 7.9 should be amended to avoid the possible perception of bias.

The following amendment is required before the Access Arrangement will be approved.

Amendment 8

Clause 7.9 of the General Terms and Conditions should be amended to the effect that the Tubridgi Parties will not correct readings taken from any metering equipment more than one year prior to the relevant test other than if agreed to with the User or if the Tubridgi Parties are required to do so by law.

Gas Specifications and Pressures (Clauses 8 and 9 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  No gas specifications are provided in the documentation. Clause 8.1 of the General Terms and Conditions refers only to "specifications reasonably specified from time to time by the Tubridgi Parties by notice given to the User". Receipt Pressure is similarly treated in clause 9.1 of the General Terms and Conditions. CMS would query whether or not such specifications should not form a part of the documentation otherwise specified in detail in order to comply with regulatory requirements.

The Tubridgi Parties have indicated to the Regulator that gas specifications and pressures are not directly set out in the Access Arrangement documentation in order to give the Tubridgi Parties the flexibility to tailor specifications and pressures to changing circumstances without having to amend the Access Arrangement documentation or apply the same specifications and pressures in all circumstances.

The Regulator appreciates the reasoning put forward by the Tubridgi Parties, but is of the opinion that the Access Arrangement should commit the Tubridgi Parties to accepting gas of a predetermined quality specification and pressure into the Tubridgi Pipeline System, while possibly allowing for variation from this quality specification and pressure by agreement with individual Users.

The following amendments are required before the Access Arrangement will be approved.

Amendment 9

Clause 8.1 of the General Terms and Conditions should be amended to indicate the range of gas quality specifications within which gas can be delivered to the Tubridgi Pipeline System.

Amendment 10

Clause 9.1 of the General Terms and Conditions should be amended to indicate the pressure range within which gas can be delivered to the Tubridgi Pipeline System.

Supply Curtailment (Clause 13 of the General Terms and Conditions)

- Western Power

  There is no refund to Users whenever the Tubridgi Parties interrupt delivery for maintenance, repairs, improvements or alternatives to the Tubridgi Pipeline System (clauses 13.1(a) and 13.2 of the General Terms and Conditions). The charge for each GJ of MDQ ($ per month) is payable for a User's capacity reservation, which may be interrupted by the Tubridgi Parties.

The Australian pipeline industry does not provide a uniform approach to waiving of reservation charges when gas transportation is interrupted.

In Western Australia, the Dampier to Bunbury Natural Gas Pipeline a proportionate refund of capacity reservation charge is currently provided for in certain circumstances in which the pipeline owner interrupts delivery or transportation.[4] The proposed Access Arrangement for the Parmelia Pipeline makes provision for charges for reserved capacity to apply irrespective of the delivery of gas, although the Draft Decision on this Access Arrangement requires the Access Arrangement to be amended to provide for the waiving of capacity reservation charges when transportation of gas is curtailed or interrupted to an extent beyond that provided for by a specified degree of pipeline reliability.

In other Australian states, proposed Access Arrangements for transmission pipelines have in some instances made provision for waiving of capacity charges where gas transmission is interrupted for reason of force majeure events,[5] and in some instances have not made any provision for waiving of charges.[6]

In view of provisions of other proposed Access Arrangements for waiving of capacity charges in response to service interruptions, a common practice appears to be emerging in the Australian pipeline industry of waiving capacity charges where services are interrupted for reason of force majeure events, but making no provision for waiving of charges for other interruptions.

In regard to curtailment of services as a result of a force majeure event, the liability of a User for the fixed charges of Reference Tariffs when supply of a Reference Services is curtailed affects the identity of the parties that, in the first instance, bear the financial risk associated with this liability. In principle, the identity of the party that bears the risk in the first instance would be largely inconsequential, as there would be a compensating effect in the Reference Tariffs. Furthermore, the Regulator notes that the principle risk associated with a force majeure interruption to services would arise in relation the economic losses incurred by end-users of gas, rather than any liability to pay the fixed charges of transmission tariffs.

In a practical sense, the Regulator’s objective in determining an assignment of financial risk associated with force majeure events is to ensure that the party that bears the risk in the first instance is the party that is in the best position to manage the risk and to remedy any failure arising from a force majeure event. In particular, where the Service Provider is in the best position to manage the risks of force majeure, the Access Arrangement should ensure that it is the Service Provider that bears the financial risk of force majeure in the first instance. The current provisions of the Access Arrangement assign the financial risk in most part to Users of the Tubridgi Pipeline System regardless of whether it is the Tubridgi Parties or the User that would be in the best position to manage the risk of force majeure.

The Regulator is therefore of the view that the Access Arrangement should be changed to the provide for the waiving of fixed charges of a Reference Tariff for any period in which provision of a Reference Service is interrupted or reduced by a failure of the Tubridgi Parties to carry out any of its obligations under a Haulage Contract for reasons of force majeure.

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[4] Epic Energy, 10 March 1998. DBNGP Access Manual sub-chapter 3.2.

[5] Proposed Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999); proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999); proposed Access Arrangement for the Central West Pipeline (AGL Pipelines (NSW) Pty Limited, 31 December 1998).

[6] Proposed Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999)

The following amendment is required before the Access Arrangement will be approved.

> Amendment 11
>
> The Access Arrangement should be amended to the effect that, for any period in which provision of a Reference Service is interrupted or reduced by a failure of the Tubridgi Parties to carry out any of their obligations under a service contract for reasons of force majeure, the fixed charges of the Reference Tariff are waived to the extent to which the provision of the service is reduced.

The proposal by the Tubridgi Parties to not waive reservation charges where services are interrupted for reasons other than force majeure events is considered by the Regulator to be consistent with common practice in the industry. Notwithstanding this, the General Terms and Conditions could be made more equitable in the sharing of risks associated with interrupted transportation through such measures as specifying a pipeline reliability figure which, if breached by the Service Provider, would result in a waiving of reservation charges.

> Amendment 12
>
> The Access Arrangement should be amended to specify the degree of reliability for the Haulage Reference Service and to indicate that capacity reservation charges (in $/GJ of MDQ) will be waived when deliveries of gas into, through or out of the Tubridgi Pipeline System are curtailed or interrupted to an extent beyond that provided for by the specified degree of reliability.

- CMS Gas Transmission Australia

  Clause 13 of the General Terms and Conditions deals with supply curtailment by the Service Provider and gives rise to a number of queries. Clause 13.1(d) mysteriously provides for curtailment if there is insufficient gas being delivered into the pipeline system to meet demand. What is the intention? Clause 13.1(e) provides for curtailment in response to gas imbalance but does not specify how this should be determined nor provide any tolerance. Should it not? Furthermore clause 13.2 specifies advance notice to Users of as little as 14 days for interruptions to service. This seems to be too short. In addition, CMS suggests that advance notice according to a pre-specified annual maintenance plan should be provided to Users.

Information provided to the Regulator by the Tubridgi Parties indicates that the intent of clauses 13.1(d) and 13.1(e) of the General Terms and Conditions is to allow maintenance of overall gas balances within the pipeline system and thereby the operational integrity of the pipeline. The Tubridgi Parties also indicated that clause 13.1(e) relates to obligations of a User under clause 3.3 of the General Terms and Conditions to ensure that a gas balance is maintained in respect of the User. However, provided that a User is in compliance with apportionment agreements (under clause 4.5 of the Access Arrangement), the User could not experience a gas imbalance, and hence would not be at risk of curtailment under clause 13.1(e) of the General Terms and Conditions. The Regulator is of the opinion that these provisions are reasonable.

The provision for 14 days notice to be given to Users prior to curtailment of services for the purposes of planned maintenance or augmentation of the Tubridgi Pipeline System is, in the Regulators opinion, in accordance with common industry practice that varies from making no provision for notice,[7] through providing reasonable notice,[8] to specifying a period of notice.[9] The provision for notice proposed by the Tubridgi Parties is therefore regarded as reasonable on the basis that it is consistent with common industry practice.

Charges and Invoices (Clause 14 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  According to clause 14.5 of the General Terms and Conditions, invoices are due for payment within 7 days (with no indication that these should be taken as "business days"). This is too short, especially when clause 18.4 of the General Terms and Conditions stipulates that if the due date falls on other than a business day, payment is due on the last preceding business day.

The Tubridgi Parties have indicated to the Regulator that the seven day period for payment of invoices is considered by the Tubridgi Parties to be reasonable on the basis that any invoiced sum would predominantly comprise readily predictable charges based on the MDQ of the User, and that any period longer than seven days would expose the Tubridgi Parties to an unacceptable credit risk.

In forming an opinion on the reasonableness of the seven day period for payment of invoices, the Regulator considered payment periods for other transmission pipelines under Access Arrangements or proposed Access Arrangements. Periods for payment have typically been set at 14 days[10], although shorter periods have been accepted by regulators.[11] The Regulator is of the opinion that while a seven day period for payment of invoices is consistent with industry practice, it is not reasonable as the seven day period is sufficiently short that it may lead to regular breaching of payment conditions. A period of 14 days for payment of invoices would appear more reasonable.

The following amendment is required before the Access Arrangement will be approved.

> Amendment 13
>
> Clause 14.5 of the General Terms and Conditions should be amended to provide for a maximum period for payment of invoices of no less that 14 days.

[7] For example, the proposed Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999) and the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999).

[8] For example, the proposed Access Arrangement for the Central West Pipeline (AGL Pipelines (NSW) Pty Limited, 31 December 1998).

[9] For example, the proposed Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999)

[10] Fore example, the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999), the proposed Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999), the proposed Access Arrangement for the Central West Pipeline (AGL Pipelines (NSW) Pty Limited, 31 December 1998), and the proposed Access Arrangement for the Parmelia Pipeline (CMS Gas Transmission of Australia, 7 May 1999).

[11] For example, a 7 day period under the proposed Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999).

- Western Power

  The standard procedure for disputed quantities / prices, is for the User to pay the undisputed portion of the invoice, with the balance subject to further investigation. The Tubridgi Parties request Users to pay the full amount of the invoice, regardless of dispute, and may cease delivery of gas to the User under the failure to pay provision.

Clause 18.3 of the General Terms and Conditions requires that payments be made by Users in full without set-off, counterclaim or deduction, or withholding on any account whatsoever. Thus the General Terms and Conditions require payment in full of any disputed invoice.

Requirements of pipeline operators vary in respect of payment of disputed invoices, allowing for withholding of disputed amounts[12] and for payment in full with the exception of manifest errors in an invoice.[13] In view of this range of arrangements for other gas pipelines, the Regulator considers it reasonable for the Tubridgi Partners to require payment of disputed invoices in full prior to settlement of a dispute, subject to provision for non-payment in situations of a manifest error in the disputed invoice.

The following amendment is required before the Access Arrangement will be approved.

Amendment 14 Clause 18 of the General Terms and Conditions should be amended to allow for the non-payment of disputed invoices, or the disputed portion of an invoice, in instances of a manifest error in the invoice.

Billing Quantities (Clause 15 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  In the absence of meter readings, billing quantity estimates are specified to be "on whatever basis the Tubridgi Parties consider reasonable" (clause 15.2 of the General Terms and Conditions). CMS would argue that the basis for such estimates should be by agreement with Users. The determination process for gas allocation similarly excludes input from the User (clauses 15.3 and 15.4 of the General Terms and Conditions) and CMS is of the opinion that it should therefore be amended. Further, it is not clear how this process relates to the mandatory requirement for an apportionment agreement between all parties as specified in section 4.3 of the Access Arrangement.

Information provided to the Regulator by the Tubridgi Parties indicated that the intent of clause 15.2 of the General Terms and Conditions is to enable the Tubridgi Parties to specify an allocation of gas on a reasonable basis without the complications and costs of consultation and agreement with Users. While the wording of clause 15.2 suggests that the Tubridgi Parties maintain discretion in the interpretation of "reasonable" in this context, the Tubridgi Parties have indicated a view that this clause would have the effect of binding the Tubridgi Parties in any dispute to a broader criterion of reasonableness whereby any determination of billing quantities must be made on a reasonable basis.

[12] For example, under the Access Manual for the Dampier to Bunbury Natural Gas Pipeline (Epic Energy).

[13] For example, under the proposed Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999) and the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999).

A variety of provisions exist under other Access Arrangements or proposed Access Arrangements for determination of billing quantities in the absence of meter readings, including no provision at all,[14] discretionary provisions for the Service Provider,[15] determination by agreement with Users,[16] and specified procedures for determination.[17] In view of the absence of a common industry practice for determining billing quantities in the absence of meter readings, the Regulator is of the opinion that provisions for the exercise of discretion by the Tubridgi Parties in clause 15.2 of the General Terms and Conditions is appropriate, but that the exercise of discretion should be constrained by a broader conception of reasonableness.

The following amendment is required before the Access Arrangement will be approved.

Amendment 15 Clause 15.2 of the General Terms and Conditions should be amended to indicate that the determination of billing quantities in the absence of meter readings will be undertaken on a basis that is determined by the Tubridgi Parties and that is reasonable.

Clause 15.3 of the General Terms and Conditions relates to situations where gas is received into the Tubridgi Pipeline System by more than one User at a single User receipt point. The clauses makes provision for the Tubridgi Parties to determine at which times they received and delivered gas for each User on whatever basis the Tubridgi Parties consider reasonable. The Tubridgi Parties have indicated to the Regulator that if an apportionment agreement establishes a basis for allocating gas between multiple Users, then it would be unreasonable for the Tubridgi Parties to ignore the agreement, and such an agreement would prevail in determining a gas allocation. The Regulator is of the opinion that, for the purposes of clarity, the impact of apportionment agreements on gas allocation in the absence of meter readings should be stated under clause 15 of the General Terms and Conditions.

The following amendment is required before the Access Arrangement will be approved.

Amendment 16 Clauses 15.2 and 15.3 of the General Terms and Conditions should be amended to indicate that the determination of billing quantities in the absence of meter readings will be undertaken in accordance with provisions of relevant apportionment agreements.

[14] For example, the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999).

[15] For example, the proposed Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999).

[16] For example, the proposed Access Arrangement for the Central West Pipeline (AGL Pipelines (NSW) Pty Limited, 31 December 1998).

[17] For example, the Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999).

Liabilities Arising from Failure to Pay Invoices (Clause 19 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  Under clause 19.1 of the General Terms and Conditions, interest penalties unpaid at the end of a month are capitalised and the interest compounded. CMS suggests that this provision should be removed or amended in favour of some more equitable arrangement.

The imposition of interest penalties on Users for overdue payments is common practice for gas transmission businesses[18], although explicit provision is not typically made for the capitalisation and compounding of any unpaid interest penalties, with the noted exception of the Mildura Pipeline. Nevertheless, the Regulator is of the opinion that this practice is reasonable.

- CMS Gas Transmission Australia

  Clause 19.2 of the General Terms and Conditions provides individual Tubridgi Parties the right to offset unpaid amounts against "any and all other amounts owing or due" by the User. This appears to effectively link unrelated business transactions and CMS questions the propriety of such a clause.

The Regulator notes that provision for the offset of debts against credits to the debtor in otherwise unrelated transactions is a generally accepted commercial practice, although the Regulator is only aware of such a provision being included in one other Access Arrangement.[19] As such, the Regulator has no in-principle concern with clause 19.2 of the General Terms and Conditions. However, it is noted that while clause 19.2 makes provision for the Tubridgi Parties to offset amounts payable by a User against any amounts due or owing by any of the Tubridgi Parties to the User, clause 18.3 of the General Terms and Conditions prevents a User from making use of a similar offset provision. The Regulator is of the opinion that the asymmetry in the provisions for the offset of debts is unreasonable.

The following amendment is required before the Access Arrangement will be approved.

Amendment 17 Clauses 18.3 and 19.2 of the General Terms and Conditions should be amended such that any capacity for the Tubridgi Parties to offset debt and credit is also available to Users.

- CMS Gas Transmission Australia

  Clause 19.3 of the General Terms and Conditions does not allow for any grace period before the right to suspend services in response to any unpaid amounts due is exercised. This does not seem reasonable.

The Regulator has noted that Access Arrangements for transmission pipelines typically allow for a seven-day notice period before a Service Provider may suspend or terminate a service in

[18] For example, under the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999), the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999), the Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999), and the proposed Access Arrangement for the Central West Pipeline (AGL Pipelines (NSW) Pty Limited, 31 December 1998).

[19] Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999)

response to a default on payment,[20] although there is at least one instance of an Access Arrangement not providing for any notice period.[21] The AlintaGas Access Arrangement for the Mid-West and South-West Gas Distribution Systems makes provision for a five business period for a User to remedy a payment default. The Regulator is of the opinion that a seven day (or five business day) notice period is reasonable.

The following amendment is required before the Access Arrangement will be approved.

Amendment 18 Clause 19.3 of the General Terms and Conditions should be amended to make provision for a seven day notice period before a service can be suspended for a User failing to pay an amount due to the Tubridgi Parties under a service agreement.

Requirements for Bank Guarantees (Clause 20 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  Under clause 20.3 of the General Terms and Conditions, the User's Bank Guarantee (which is based on MDQ) must be maintained at equivalent to at least 2 months charges under all circumstances. This seems onerous particularly as according to clause 4.4 of the General Terms and Conditions MDQ is ratcheted up from the day following any excursion of peak daily quantity and that additionally under clause 20.6 of the General Terms and Conditions, failure to meet this condition relieves the Tubridgi Parties of "any obligation to comply with the terms of the [transport] Agreement".

  Furthermore, clause 20.4 of the General Terms and Conditions does not clearly define what restricts the Service Provider from calling on the User's bank guarantee in response to even minor transgressions of the User's obligations. It also provides that the Service Provider may call upon the bank guarantee <u>without</u> notice to the User. Some modifications appear to be required to this section in order to safeguard the legitimate interests of Users.

The Regulator is of the opinion that a requirement for a bank guarantee, and the requirement that the bank guarantee be maintained at an amount equal to at least two months charges under a service agreement, are reasonable. It is noted, however, that the charges for which a User is liable will vary with any change in that User's MDQ. If provision is retained in the Access Arrangement for a User's MDQ to vary in response to realised peak daily quantities for that User (refer to Amendment 7), then it would be reasonable for the General Terms and Conditions to allow for a period of time to alter the amount of the bank guarantee.

The following amendment is required before the Access Arrangement will be approved.

Amendment 19 Clause 20 of the General Terms and Conditions should be amended to provide a reasonable period of time for a User to alter the amount of a bank guarantee in response to any change in the amount of charges for which the User would be liable.

[20] For example, the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999) and the Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999).

[21] Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999).

Clause 20.4 of the General Terms and Conditions provides for the Tubridgi Parties to call on the bank guarantee at any time, and without notice to the User, if the User fails to perform any of the User's obligations under the Service Agreement. Clause 20.4 is not specific as to the purposes for which the Tubridgi Parties may call on the bank guarantee, although the Tubridgi Parties have indicated to the Regulator that the bank guarantee may be called upon for an amount the Tubridgi Parties are owed or the amount of a loss incurred by the Tubridgi Parties as a result of the User not meeting obligations under a service agreement.

The Regulator is of the opinion that provisions of clause 20.4 are not reasonable. The circumstances under which the Tubridgi Parties may call on a bank guarantee are considered to be inadequately defined given that the intent of the Tubridgi Parties appears to be able to recover losses over and above those arising solely from unpaid invoices.

The following amendment is required before the Access Arrangement will be approved.

Amendment 20 Clause 20 of the General Terms and Conditions should be amended to describe the circumstances in which, and the potential liabilities of Users for which, the Tubridgi Parties may call upon a bank guarantee.

Termination of Agreement (Clause 21 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  Termination of an Agreement can be as a result of failure to pay, breach of obligation, insolvency, reduced credit rating or if "there is any material adverse change, *in the opinion of the Tubridgi Parties*, in the ability of the pipeline User to comply with its obligations…" (clause 21.2 of the General Terms and Conditions). This latter discretion contained in clause 21.2(e) appears to excessively rely upon opinion rather than evidence.

The Regulator considers that while the exercise of discretion would be of benefit to both the Tubridgi Parties and Users in exercising any contractual clause for termination of a service agreement, any provision for discretion must be consistent with a basis for arbitration should a dispute arise. For this reason, the Regulator is of the opinion that the Tubridgi Parties should be limited to exercise of *reasonable* discretion.

The following amendment is required before the Access Arrangement will be approved.

Amendment 21 Clause 21.2(e) of the General Terms and Conditions should be amended to provide for the Tubridgi Parties to terminate a service agreement where, in the *reasonable* opinion of the Tubridgi Parties, there is a material adverse change in the ability of the User to comply with its obligations under a service agreement.

- CMS Gas Transmission Australia

  Where a breach of obligation can be remedied, the User has 14 days (specified under clause 21.2(b) of the General Terms and Conditions) from notification to effect remedial action. CMS would argue that this time limit may prove somewhat short in certain circumstances, for instance where unforeseen replacement parts might have to be procured, transported to a remote location and fitted. A limit of 28 days might be more appropriate.

In forming an opinion on the reasonableness of a 14 day period for a User to remedy a default prior to the Tubridgi Parties being able to terminate the service agreement, the Regulator considered practices for other transmission pipelines. Industry practice typically varies from providing periods of 14 to 28 days for remedy of defaults by the User.[22] In addition, the AlintaGas Access Arrangement for the Mid-West and South-West Gas Distribution Systems makes provision for a 15 business day period for a User to remedy a default other than a payment default. In the absence of supporting argument to support a case to the contrary, the Regulator is of the opinion that provision of a 21 day (or 15 business day) period for remedy of defaults by the User is reasonable.

The following amendment is required before the Access Arrangement will be approved.

> Amendment 22
>
> Clause 21.2(b) of the General Terms and Conditions should be amended to provide for a 21 day period for a User to remedy a breach of an obligation under a service agreement (other than an obligation to pay an amount due to the Tubridgi Parties), prior to the Tubridgi Parties being able to terminate the agreement.

Decommissioning of the Tubridgi Pipeline System (Clause 21.4 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  Decommissioning of either receipt or delivery points or the entire pipeline system can be effected at the sole discretion of the Tubridgi Parties only requiring that Users be given at least 3 months notice (clauses 21.4, 22.1 and 22.2 of the General Terms and Conditions). The form of notice is not specified and CMS suggests that it might avoid potential for conflicts of understanding if it were. It might also be considered reasonable that some form of justification for decommissioning of facilities be provided as part of such notice.

The Regulator recognises that given the uncertain future demand for gas transportation through the Tubridgi Pipeline System, some or all of the assets of the pipeline system may become redundant. As indicated in the submission on the Access Arrangement by the Office of Energy, the Tubridgi Parties have highlighted this possibility in their application to the National Competition Council for revocation of coverage of the Tubridgi Pipeline. The Office of Energy also indicated that in the decision in respect of coverage of the Tubridgi Pipeline, the WA Minister for Energy considered that Coverage and the development of an Access Arrangement for the Pipeline should not prevent the Tubridgi Parties from either decommissioning or abandoning the Tubridgi Pipeline in the event that in 2001 there is no reasonably foreseeable demand for its services.

The Regulator considers that any decision by the Tubridgi Parties to decommission particular assets of the Tubridgi Pipeline System should be a commercial decision. In particular, the Tubridgi Parties should not be prevented for decommissioning the Tubridgi Pipeline and utilising the Griffin Pipeline for all gas transportation. However, the Regulator does not

[22] For example, a 14 day period is provided under the Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999), 21 day periods are provided under the proposed Access Arrangement for the Moomba to Sydney Pipeline (East Australian Pipeline Limited, 5 May 1999) and the Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999), and a 28 day period is provided under the proposed Access Arrangement for the Parmelia Pipeline (CMS Gas Transmission Australia, 7 May 1999).

consider it reasonable for any existing service agreements between the Tubridgi Parties and a User to be subject to a decision to decommission assets as this would create uncertainty of contract duration for Users with potential discouragement of investment in upstream gas production.

The following amendment is required before the Access Arrangement will be approved.

Amendment 23 Clauses 21.4, 22.1 and 22.2 of the General Terms and Conditions should be deleted so as to remove provision for any existing service agreements to be contingent upon decisions by the Tubridgi Parties to decommission the Tubridgi Pipeline System, parts of the Tubridgi Pipeline System, receipt points or delivery points.

Notwithstanding this required amendment, the Regulator does not consider it reasonable that the Tubridgi Parties should be obliged to enter into any new service agreements that are contrary to pre-existing plans to decommission part or all of the Tubridgi Pipeline System. The Tubridgi Parties may wish to consider this in amendments to the Access Arrangement.

Liability of the Tubridgi Parties (Clause 23 of the General Terms and Conditions)

- CMS Gas Transmission Australia

  Claims against the Service Provider are limited to one month from the time the claim is first known or <u>should</u> have become known to the User (clause 23.2 of the General Terms and Conditions). CMS contends that this limitation should be removed.

Australian Access Arrangements for transmission pipelines have typically not stated a limitation of time for claims to be made by Users against the Service Provider. Two exceptions occur with the proposed Access Arrangement for the Moomba to Adelaide Pipeline System,[23] for which an 18 month time limit is placed on claims by either Users or the Service Provider for an amount over charged or undercharged, and the proposed Access Arrangement for the Mildura Pipeline,[24] for which a one month time limit is placed on claims by Users.

The Regulator has no in-principle concern over time limits being placed on the making of claims. However, the Regulator considers that where time limits are imposed, it is reasonable to expect that they would apply equally to both the Service Provider and Users.

The following amendment is required before the Access Arrangement will be approved.

Amendment 24 The General Terms and Conditions should be amended such that any time limitation imposed on claims between parties to a service agreement, or requirements for the provision of information in relation to claims, applies equally to all parties.

[23] Epic Energy South Australia Pty Ltd, April 1999. Access Arrangement for the Moomba to Adelaide Pipeline System.

[24] Envestra Limited, February 1999. Access Arrangement for the South Australian Distribution System.

- CMS Gas Transmission Australia

  Clause 23.3 of the General terms and Conditions limits liability of the Tubridgi Parties to separate individual proportions. CMS considers that it may be necessary to obtain legal advice as to whether liability should be "joint and several" given the wording of the rest of the Tubridgi Access Arrangement in regard to the precise nature of any shared liability between the Tubridgi Joint Venture Parties and the Operator acting on their behalf.

The Regulator obtained legal advice on this matter indicating that, as a joint venture, the Tubridgi Parties are not members of a partnership that would be liable jointly and severally for partnership debts and liabilities. In these circumstances it would not appear to be unreasonable for joint venture partners to seek to limit their liability to their interest in the joint venture.

Of more concern to the Regulator is the provision of clause 23.3 of the General Terms and Conditions that would appear to limit the amount of any claim by a User against the Tubridgi Parties to the amount of the charges paid by the User to the Tubridgi Parties in the calendar month in which the claim arose. It is unclear whether the nature of claims relevant to clause 23.3 would encompass all claims possible made against the Tubridgi Parties, in which case the provisions of Clause 23.3 would appear to impose an unreasonable constraint on Users.

Amendment 25 Clause 23.2 of the General Terms and Conditions should be amended to clarify the nature of claims relevant to this clause and to ensure that there is no unreasonable limit on the size of claims able to be made by a User against the Tubridgi Parties.

Force Majeure (Clause 25 of the General Terms and Conditions)

- AlintaGas Trading

  Clause 25.2 of the General Terms and Conditions details the consequences of non-performance by the Tubridgi Parties of their obligations as a result of force majeure. A similar clause is required to relieve the User of its obligations during an event of force majeure.

The Tubridgi Parties have indicated to the Regulator that the force majeure clause should not apply to Users for reasons that:

- the principal obligations of Users are to make payments and it is not appropriate or reasonable to allow a User to claim force majeure in respect of payment obligations;
- most of the obligations of Users are obligations which are completely within their control and not subject to force majeure events; and
- while the condition (quality and pressure) of the gas that Users are able to deliver to the pipeline may not be completely under the control of the Users, it is not appropriate or necessary to give force majeure relief in respect of gas condition as the User is under no obligation to deliver gas to the Tubridgi Pipeline System and the User could readily suspend delivery if obligations relating to gas condition could not be met.

The Regulator considers that some obligations of Users under a service agreement may be subject to non-performance as a result of force majeure events. This would include ensuring that the Tubridgi Parties may remotely access metering equipment (clause 5.2 of the General Terms and Conditions) and maintaining metering equipment in a reasonable condition (clause 5.3). As such, the Regulator considers that the General Terms and Conditions should relieve Users from such obligations when the obligations are unable to be met as a result of force majeure events.

The following amendment is required before the Access Arrangement will be approved.

Amendment 26 Clause 25 of the General Terms and Conditions should be amended such that a User is not liable to the Service Provider for any failure, as a result of force majeure, to perform an obligation under a service agreement other than an obligation to make payments.

4.3.4 Additional Considerations of the Regulator

Lost or Unaccounted-For Gas

Clause 11.5 of the General Terms and Conditions makes provision for the Tubridgi Parties to have discretion in the apportionment of lost or unaccounted-for gas amongst Users of the pipeline system. Similar to the provisions of clause 15.2 of the General Terms and Conditions in respect of determining billable quantities of gas in the absence of meter readings, it is likely that the intent of clause 11.5 is to enable the Tubridgi Parties to specify an allocation of unaccounted-for gas on a reasonable basis without the complications and costs of consultation and agreement with Users on a basis for allocation.

The Regulator is of the view that any reasonable basis for the allocation of unaccounted-for gas is likely to be contingent upon the protocols for apportionment of gas transported in the pipeline, as established by apportionment agreements. As such, the Regulator is of the opinion that, for the purposes of clarity, the impact of apportionment agreements on the basis for apportionment of unaccounted for gas should be recognised in clause 11.5 of the General Terms and Conditions.

The following amendment is required before the Access Arrangement will be approved.

Amendment 27 Clause 11.5 of the General Terms and Conditions should be amended to indicate that the apportionment of lost or unaccounted-for gas will be undertaken on a basis that is consistent with provisions of relevant apportionment agreements.

Rights of the Tubridgi Parties to Curtail Supply

Clause 13.1(e) of the General Terms and Conditions provides for the Tubridgi Parties to curtail supply when the quantity of gas delivered into the Tubridgi Pipeline System by or for the account of the pipeline User is not equal to the quantity of gas delivered out of the Tubridgi Pipeline System to or for the account of the pipeline User (or will or may not be equal unless deliveries of gas are curtailed or interrupted).

The Regulator is of the view that the Tubridgi Parties are only justified in curtailing supply if the quantity of gas delivered into the Tubridgi Pipeline System by or for the account of the pipeline User is *less than* the quantity of gas delivered out of the Tubridgi Pipeline System to or for the account of the pipeline User. It is only with this form of imbalance that problems may be created in pipeline operation.

The following amendment is required before the Access Arrangement will be approved.

Amendment 28 Clause 13.1(e) of the General Terms and Conditions should be amended to limit the rights of the Tubridgi Parties to curtail supply to the imbalance situation that arises where the quantity of gas delivered into the Tubridgi Pipeline System by or for the account of the pipeline User is *less than* the quantity of gas delivered out of the Tubridgi Pipeline System to or for the account of the pipeline User (or will or may be less than unless deliveries of gas are curtailed or interrupted).

4.4 CAPACITY MANAGEMENT POLICY

4.4.1 Access Code Requirements

Section 3.7 of the Code requires that an Access Arrangement include a statement (a Capacity Management Policy) that the Covered Pipeline is either:

(a) a Contract Carriage Pipeline; or

(b) a Market Carriage Pipeline.

Contract Carriage is a system of managing third party access whereby:

(a) the Service Provider normally manages its ability to provide services primarily by requiring Users to use no more than the quantity of service specified in a contract;

(b) Users normally are required to enter into a contract that specifies a quantity of service;

(c) charges for use of a service normally are based at least in part upon the quantity of service specified in a contract; and

(d) a User normally has the right to trade its right to obtain a service to another User.

Market Carriage is a system of managing third party access whereby:

(a) the Service Provider does not normally manage its ability to provide services primarily by requiring Users to use no more than the quantity of service specified in a contract;

(b) Users are not normally required to enter into a contract that specifies a quantity of service;

(c) charges for use of services are normally based on actual usage of services; and

(d) a User does not normally have the right to trade its right to obtain a service to another User.

Section 3.8 of the Code requires that the Regulator must not accept an Access Arrangement which states that the covered pipeline is a Market Carriage Pipeline unless the Relevant Minister of each scheme participant in whose jurisdictional area the pipeline is wholly or partly located has given notice to the Regulator permitting the covered pipeline to be a Market Carriage Pipeline.

4.4.2 Access Arrangement Proposal

In clause 5 of the Access Arrangement the Tubridgi Parties propose to manage the Tubridgi Pipeline System as a Contract Carriage Pipeline.

4.4.3 Submissions from Interested Parties

None of the submissions made in respect of the Tubridgi Pipeline System Access Arrangement addressed the proposed Capacity Management Policy.

4.4.4 Additional Considerations of the Regulator

The Regulator recognises that the Code requires no more than a statement in the Access Arrangement that the Covered Pipeline is a Contract Carriage or Market Carriage pipeline, subject to Ministerial approval for any proposal for the pipeline to be a Market Carriage Pipeline. As the Access Arrangement proposes that the pipeline is to be managed as a Contract Carriage Pipeline, it is considered that the requirements of the Code are met.

4.5 TRADING POLICY

4.5.1 Access Code Requirements

Section 3.9 of the Code requires that an Access Arrangement for a Covered Pipeline, which is described in the Access Arrangement as a Contract Carriage Pipeline, must include a policy that explains the rights of a User to trade its right to obtain a service to another Person (a Trading Policy).

Section 3.10 of the Code requires that the Trading Policy must comply with the following principles.

(a) A User must be permitted to transfer or assign all or part of its Contracted Capacity without the consent of the Service Provider concerned if:

   (i) the User's obligations under the contract with the Service Provider remain in full force and effect after the transfer or assignment; and

   (ii) the terms of the contract with the Service Provider are not altered as a result of the transfer or assignment (a Bare Transfer).

In these circumstances the Trading Policy may require that the transferee notify the Service Provider prior to utilising the portion of the Contracted Capacity subject to the Bare Transfer and of the nature of the Contracted Capacity subject to the Bare Transfer, but the Trading Policy must not require any other details regarding the transaction to be provided to the Service Provider.

(b) Where commercially and technically reasonable, a User must be permitted to transfer or assign all or part of its Contracted Capacity other than by way of a Bare Transfer with the prior consent of the Service Provider. The Service Provider may withhold its consent only on reasonable commercial or technical grounds and may make its consent subject to conditions only if they are reasonable on commercial and technical grounds. The Trading Policy may specify conditions in advance under which consent will or will not be given and conditions that must be adhered to as a condition of consent being given.

(c) Where commercially and technically reasonable, a User must be permitted to change the Delivery Point or Receipt Point from that specified in any contract for the relevant service with the prior written consent of the Service Provider. The Service Provider may withhold its consent only on reasonable commercial or technical grounds and may make its consent subject to conditions only if they are reasonable on commercial and technical grounds. The Trading Policy may specify conditions in advance under which consent will or will not be given and conditions that must be adhered to as a condition of consent being given.

Section 3.11 of the Code states that examples of things that would be reasonable for the purposes of section 3.10(b) and (c) are:

(a) the Service Provider refusing to agree to a User's request to change its Delivery Point where a reduction in the amount of the service provided to the original Delivery Point will not result in a corresponding increase in the Service Provider's ability to provide that service to the alternative Delivery Point; and

(b) the Service Provider specifying that, as a condition of its agreement to a change in the Delivery Point or Receipt Point, the Service Provider must receive the same amount of revenue it would have received before the change.

4.5.2 Access Arrangement Proposal

A Trading Policy is provided by the Tubridgi Parties in clause 6 of the Access Arrangement.

The Trading Policy provides for Bare Transfers and other transfers consistent with requirements of the Code. Information is provided in respect of the rights of the Tubridgi Parties in respect of transfers, as follows.

i. Requirements on Users to notify the Tubridgi Parties of details of Bare Transfers prior to use of the subject contracted capacity (Access Arrangement clause 6.1).

ii. An indication that the Tubridgi Parties may withhold consent to transfers, other than Bare Transfers, only on reasonable commercial and technical grounds, including:

- where there is insufficient capacity at any point in the Tubridgi Pipeline System to enable the proposed capacity to be transferred or assigned to the proposed User Delivery Point;
- where the Tubridgi Parties would receive less revenue as a result of the proposed transfer or assignment of contracted capacity; and
- where the proposed transferee is unable to satisfy the conditions that would apply to a Prospective User as conditions precedent to obtaining a service and which are set out in clause 4.3 of the Access Arrangement (Access Arrangement clause 6.2).

The Trading Policy also makes provision for changes of Delivery Points and Receipt Points subject to the ability of the Tubridgi Parties to withhold consent on reasonable commercial and technical grounds including:

- where there is insufficient capacity at any point in the Tubridgi Pipeline System to enable the proposed Receipt Point or Delivery Point to be changed; and
- where the Tubridgi Parties would receive less revenue as a result of the proposed transfer or assignment of contracted capacity (Access Arrangement 6.3).

The Trading Policy makes provision for charge of fees in respect of applications for capacity transfers and for changes in Receipt Points and Delivery Points, and for the Tubridgi Parties to recover from the relevant Users any costs incurred in assessing such applications (Access Arrangement clause 6.3).

4.5.3 Submissions from Interested Parties

None of the submissions made in respect of the Tubridgi Pipeline System Access Arrangement addressed the proposed Capacity Management Policy.

4.5.4 Additional Considerations of the Regulator

Bare Transfers

Clause 6.1 of the Access Arrangement provides a requirement for a transferee of capacity to notify the Tubridgi Parties of the details of the transfer. The Regulator is concerned that the requirement for notification does not include the location of the User Receipt Point which is the subject of the transfer, and that this may impede the use of Bare Transfers where such a transfer would involve a change in receipt point.

The following amendment is required before the Access Arrangement will be approved.

Amendment 29 Clause 6.1 of the Access Arrangement should be amended to include a requirement that, prior to using any contracted capacity that is the subject of a Bare Transfer, the transferee must notify the Tubridgi Parties of the location of the User Receipt Point which is the subject of the transfer.

4.6 QUEUING POLICY

4.6.1 Access Code Requirements

Section 3.12 of the Code requires that an Access Arrangement must include a policy for determining the priority that a Prospective User has, as against any other Prospective User, to obtain access to Spare Capacity and Developable Capacity (and to seek dispute resolution under section 6 of the Code) where the provision of the service sought by that Prospective User may impede the ability of the Service Provider to provide a service that is sought or which may be sought by another Prospective User (a Queuing Policy).

Section 3.13 of the Code requires that the Queuing Policy must:

(a) set out sufficient detail to enable Users and Prospective Users to understand in advance how the Queuing Policy will operate;

(b) accommodate, to the extent reasonably possible, the legitimate business interests of the Service Provider and of Users and Prospective Users; and

(c) generate, to the extent reasonably possible, economically efficient outcomes.

Section 3.14 of the Code provides for the Relevant 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 of the Code, viz:

(a) the Service Provider's legitimate business interests and investment in the covered pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the covered pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline;

(d) the economically efficient operation of the covered pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users; and

(g) any other matters that the Regulator considers are relevant.

4.6.2 Access Arrangement Proposal

A Queuing Policy is provided by the Tubridgi Parties in clause 7 of the Access Arrangement.

The Queuing Policy provides for a queue to be formed whenever the Tubridgi Parties receive a request for pipeline services which they cannot fulfil because of insufficient capacity in the Tubridgi Pipeline System. The relative priorities of requests are determined according to:

- the position on the queue, as determined by the date and time at which each request was received; and
- a priority of requests for the Haulage Reference Service over requests for negotiated services, regardless of position in the queue.

The Access Arrangement provides details of operation of the Queuing Policy in respect of:

- formation of the queue;
- the order of priority of queued requests;
- notification of Prospective Users of spare capacity in the Pipeline System and requirements on Prospective Users to respond to any offer of spare capacity;
- obligations on Prospective Users with queued requests to notify the Tubridgi Parties of circumstances or events that may alter their requirements for capacity;
- notification of Prospective Users as to placement of a request in a queue, and changes in positions in a queue;
- notification of Prospective Users of relevant investigations into developable capacity or augmentation of the Tubridgi Pipeline System;
- obligations of Prospective Users to maintain a position in a queue; and
- removal of requests from a queue.

The queuing policy provides for the Tubridgi Parties to consider requests other than in order of queuing where the Tubridgi Parties are undertaking investigations of developable capacity, and in the interests of optimising design and achieving efficiency in the structure and level of tariffs.

4.6.3 Submissions from Interested Parties

Offers of Less than Requested Capacity

- CMS Gas Transmission Australia

  Under the Tubridgi Queuing Policy, failure to accept an offer of spare capacity within 10 days removes Users from the queue (clause 7.3 of the Access Arrangement). It is not clear whether the Users lose their place in the queue if the capacity offered does not fully satisfy the User's requirement. This requires clarification.

Clause 7.3 of the Access Arrangement indicates that if a Prospective User is offered capacity that is less than the prospective capacity, the Prospective User's request will be removed from the queue to the extent that it would have been satisfied by the capacity offered. The Tubridgi Parties have provided the Regulator with additional clarification on this matter, indicating that if the capacity offered does not satisfy the request, the request remains in the queue but that the requested capacity is reduced to an amount equal to the initially requested capacity minus the offered capacity. The Regulator is of the opinion that this provision is inconsistent with the legitimate business interests of Users where a User has a minimum useful requirement for a quantity of gas.

The following amendment is required before the Access Arrangement will be approved.

Amendment 30 Clause 7.3 of the Access Arrangement should be amended to the effect that if a Prospective User rejects an offer of capacity that is less than the capacity requested in the respective queued access request, then the queued access request will be maintained in the same position in the queue and maintained at the same level of requested capacity as pertained to the access request prior to the offer.

Requests for Negotiated Services

- AlintaGas Trading

  The Tubridgi Parties propose that requests for the Reference Service will rank higher in priority than requests for a Negotiated Service. However, if the terms and conditions of a Negotiated Service are not materially different to those of a Reference Service, then the Negotiated Service should probably still be classified as a Reference Service for the purposes of queuing policy. Terms and conditions that might be considered to be material are those associated with issues such as price, contract term and curtailment priority.

The Tubridgi Parties have indicated to the Regulator that the higher priority of requests for the Haulage Reference Service over requests for Negotiated Services is justified by:

- the legitimate business interests of the Tubridgi Parties, in so far as the Reference Tariff for the Haulage Reference Service is likely to be greater than the tariff for most Negotiated Services; and

- to the extent that the higher Reference Tariff is likely to reflect a greater utilisation of the Tubridgi Pipeline System and a greater willingness to pay and hence value of the service to a Prospective User, the priority of requests for the Haulage Reference Service will generate economically efficient outcomes.

The points of justification are not necessary valid. there is no reason for a tariff for a Negotiated Service to be less than the Reference Service, unless the Tubridgi Parties are contemplating Negotiated Services as comprising an interruptible or spot service that would tend to attract a discounted tariff. The second point of justification to be not generally valid in situations where there is monopoly provision of a service and consequently opportunity for the Service Provider to charge a higher tariff/price for the service than would be charged in a negotiated transaction in a competitive market, where the higher tariff does not necessarily correspond to a greater willingness to pay.

Notwithstanding he absence of justification for the stance adopted by the Tubridgi Parties, the Regulator is of the opinion that it is reasonable for the Tubridgi Parties to offer priority to requests for the Haulage Reference Service over Negotiated Services, in so far as it is not inconsistent with the requirements of the Code in respect of a Queuing Policy.

4.6.4 Additional Considerations of the Regulator

The Code implicitly requires that the Queuing Policy provide sufficient information to enable Users and Prospective Users to understand in advance how priorities of access to spare capacity or developable capacity are to be determined at times when requested capacity exceeds available spare capacity. Also, the Queuing Policy must generate, to the extent reasonably possible, economically efficient outcomes. The Regulator considers that the Queuing Policy is considered to meet these requirements.

4.7 EXTENSIONS/EXPANSIONS POLICY

4.7.1 Access Code Requirements

Section 3.16 of the Code requires that an Access Arrangement include a policy (an Extensions/Expansions Policy) which sets out:

(a) the method to be applied to determine whether any extension to, or expansion of the Capacity of, the Covered Pipeline:

  (i) should be treated as part of the Covered Pipeline for all purposes under the Code; or

  (ii) should not be treated as part of the Covered Pipeline for any purpose under the Code;

  (for example, the Extensions/Expansions Policy could provide that the Service Provider may, with the Relevant Regulator's consent, elect at some point in time whether or not an extension or expansion will be part of the Covered Pipeline or will not be part of the Covered Pipeline);

(b) how any extension or expansion, which is to be treated as part of the Covered Pipeline, will affect Reference Tariffs (for example, the Extensions/Expansions Policy could provide:

  (i) Reference Tariffs will remain unchanged but a Surcharge may be levied on Incremental Users where permitted by sections 8.25 and 8.26 of the Code; or

  (ii) 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);

(c) if the Service Provider agrees to fund New Facilities if certain conditions are met, a description of those New Facilities and the conditions on which the Service Provider will fund the New Facilities.

The Relevant Regulator may not require the Extensions/Expansions Policy to state that the Service Provider will fund New Facilities, unless the Service Provider agrees.

4.7.2 Access Arrangement Proposal

An Extensions/Expansions Policy is provided by the Tubridgi Parties in clause 8 of the Access Arrangement.

The general provisions of the Extensions/Expansions Policy are as follows.

i. Any expansion in the Capacity of the Tubridgi Pipeline System within the Access Arrangement Period will automatically be included as part of the Covered Pipeline from the time the expansion comes into service.

ii. Extensions to the pipeline of less than $75,000 in estimated capital cost or of less than 1 km in length will automatically be included as part of the Covered Pipeline from the time the extension comes into service.

iii. For extensions to the pipeline of greater than $75,000 in estimated capital cost or greater than 1 km in length, the Tubridgi Parties maintain the option of treating the extension as either part of the Covered Pipeline or as a stand-alone pipeline. In the event that the Tubridgi Parties treat an extension as a stand alone pipeline, notice to this effect will be provided to the Regulator prior to the extension entering into service.

The Extensions/Expansions Policy provides for the following effects of an extension or expansion on the Reference Tariff for the Haulage Reference Service.

- No change to the Reference Tariff where the extension or expansion meets the economic feasibility test of section 8.16(b)(i) of the Code – the anticipated incremental revenue generated by the extension or expansion exceeds the capital cost.

- Application to the Regulator for a revision to the Access Arrangement and a higher Reference Tariff where:

  ii. the extension or expansion does not meet the economic feasibility test of section 8.16(b)(i) of the Code, but the Tubridgi Parties believe the extension or expansion has system wide benefits that justify a higher Reference Tariff for all Users; or

  ii. the extension or expansion does not meet the economic feasibility test of section 8.16(b)(i) of the Code nor provides system wide benefits that, in the Regulators opinion, justify a higher Reference Tariff for all Users, but the extension or expansion is necessary to maintain the safety, integrity or Contracted Capacity of services.

Where an extension or expansion does not satisfy any of the requirements of section 8.16 of the Code, the Extensions/Expansions Policy provides for the Tubridgi Parties to apply to the Regulator to impose a surcharge in relation to the extension or expansion, or the Tubridgi Parties may agree to a Capital contribution from a User.

4.7.3 Submissions from Interested Parties

None of the submissions made in respect of the Tubridgi Pipeline System Access Arrangement addressed the proposed Extensions/Expansions Policy.

4.7.4 Additional Considerations of the Regulator

The Regulator is of the opinion that the Access Arrangement meets the requirements of the Code in respect of an Extensions/Expansions Policy.

4.8 REVIEW DATE

4.8.1 Access Code Requirements

Section 3.17 of the Code requires that an Access Arrangement include:

(a) a date upon which the Service Provider must submit revisions to the Access Arrangement (a Revisions Submission Date); and

(b) a date upon which the next revisions to the Access Arrangement are intended to commence (a Revisions Commencement Date).

In approving the Revisions Submissions Date and Revisions Commencement Date, the Regulator must have regard to the objectives for Reference Tariffs and Reference Tariff Policy in section 8.1 of the Code. In making its decision on an Access Arrangement (or revisions to an Access Arrangement) and if considered necessary having had regard to the objectives in section 8.1 of the Code, the Regulator may:

(i) require an earlier or later Revisions Submission Date and Revisions Commencement Date than proposed by the Service Provider in its proposed Access Arrangement;

(ii) require that specific major events be defined that trigger an obligation on the Service Provider to submit revisions prior to the Revisions Submission Date.

Section 3.18 of the Code provides for an Access Arrangement Period to be of any length; however, if the Access Arrangement Period is more than five years, the Regulator must not approve the Access Arrangement without considering whether mechanisms should be included to address the risk of forecasts on which the terms of the Access Arrangement were based and approved proving incorrect. These mechanisms may include:

(a) requiring the Service Provider to submit revisions to the Access Arrangement prior to the Revisions Submission Date if certain events occur, for example:

  (i) if a Service Provider's profits derived from a Covered Pipeline are outside a specified range or if the value of Services reserved in contracts with Users are outside a specified range;

  (ii) if the type or mix of Services provided by means of a Covered Pipeline changes in a certain way; or

(b) a Service Provider returning some or all revenue or profits in excess of a certain amount to Users, whether in the form of lower charges or some other form.

Where a mechanism is included in an Access Arrangement pursuant to section 3.18(a), the Regulator must investigate no less frequently than once every five years whether a review event identified in the mechanism has occurred.

4.8.2 Access Arrangement Proposal

Clause 1 of the Access Arrangement specifies that the Access Arrangement will come into effect on the date on which it is approved by the Regulator under section 2 of the Code.

Provision is made in clause 9 of the Access Arrangement for a Revisions Submission Date of 1 January 2004, and a Revisions Commencement Date of 1 July 2004. The implied term of the Access Arrangement is approximately 4 years.

Provision is made in clause 9.3 of the Access Arrangement for a revision of the Access Arrangement to be triggered. The Access Arrangement provides for the Tubridgi Parties to commission an independent report on forecast demand for the Tubridgi Pipeline System. If this report, which will be completed by 31 March 2002, identifies that demand for the Tubridgi Pipeline System is likely to exceed 20 TJ/day for each day over any period of three consecutive months between 1 July 2002 and 30 June 2004, then the Tubridgi Parties will submit revisions to the Access Arrangement to the Regulator by 30 June 2002.

4.8.3 Submissions from Interested Parties

Access Arrangement Period and Uncertain Demand for Services

- Western Power

  Western Power is aware that selecting the Access Arrangement Period is a matter of judgement and in this case is tied closely to the expected life of the existing gas fields. Due to the uncertainty of future gas demand and supply in this region, Western Power would favour an initial Access Arrangement Period of three years.

- Office of Energy

  The Access Arrangement proposes a 'trigger event' whereby the Tubridgi Parties will commission an independent report forecast demand for the Tubridgi Pipeline System. If this report, which will be completed by 31 March 2002, identifies that demand for the Tubridgi Pipeline System is likely to exceed 20TJ/day, for each day over any period of three consecutive months between 01 July 2002 and 30 June 2004 then the Tubridgi Parties will submit revisions to the Access Arrangement to the Regulator by 30 June 2002.

  The Office of Energy considers that in principle the proposed trigger event for a review of the Access Arrangement is appropriate. However, based on the demand forecasts in table 10 of the Access Arrangement, a demand of 20 TJ/day would represent increases of 270% and 670% over the currently projected demand levels for 2002/03 and 2003/04, respectively. The Office of Energy considers that the demand trigger should be reduced to a much lower level to reduce the risk of the Tubridgi Parties receiving windfall gains in the event the actual demand is substantially higher than the currently projected throughput underlining the level of the proposed Reference Tariff.

- AlintaGas Trading

  Clause 9.3 of the Access Arrangement proposes that if an independent report identifies demand for the Tubridgi Pipeline System is likely to exceed 20 TJ/day for each day over any period of three consecutive months between 1 July 2002 and 30 June 2004, then the Tubridgi Parties will submit revisions to the Access Arrangement by 30 June 2002.

  The proposed demand level of 20 TJ/day before the Access Arrangement will be reviewed would appear to be excessive. To illustrate this point: Table 2 in clause 5.2 of the Access Arrangement Information shows the Tubridgi Parties are forecasting demand of 7.5 TJ/day in 2002/03 and 3.0 TJ/day in 2003/04. An additional 10 TJ/day of demand, for example, at a 100% load factor will earn the Tubridgi Parties an extra $1.56 million per annum (in real dollars) without the parties having to submit revisions to the Access Arrangement. This seems to provide the potential for excessive windfall gains.

  A more equitable arrangement might be for revenue to be rebatable if it is earned on gas transported in excess of currently forecast volumes.

In determining an appropriate difference between realised and forecast quantities of gas throughput for the triggering of a review of the Access Arrangement, the Regulator took particular account of the objectives for a Reference Tariff of replicating the outcome of a competitive market and providing an incentive to the Service Provider to develop the market for Reference Services and other services (sections 8.1(b) and 8.1(f) of the Code).

In a competitive market, it is likely that reductions in unit costs for a service such as gas transmission would be passed on to consumers in lower unit prices. In itself, this would suggest that the Access Arrangement should be reviewed for any excess of realised throughput over forecast throughput. However, permitting a Service Provider to capture windfall gains from increasing throughput to levels greater than forecast during the Access Arrangement Period may provide an incentive for that Service Provider to increase throughput. The benefits from increased throughput (through lower unit costs) would be passed on to Users in the next Access Arrangement Period.

Information available since the Access Arrangement was submitted suggests that throughput is likely to be greater than forecast with a reduction only to approximately 6000 TJ/year by 2003/04, rather that 1000 TJ/year as forecast for the Access Arrangement.[25] The quantity of 6000 TJ/year equates to approximately 16.5 TJ/day. A trigger event based on an increase to 20 TJ per day is consistent with trigger events adopted by other Australian Regulators based on an excess in realised throughput over forecast throughput equal to 25 percent of forecast throughput.[26] However, this has been applied to pipelines and distribution systems with throughputs substantially in excess of the throughput projected for the Tubridgi Pipeline System, and where the increased revenue from a 25 percent increase in throughput above forecasts may be expected to exceed the costs of reviewing the respective Access Arrangement, with some residual benefits to be passed on to Users through lower unit tariffs. An increase of 25 percent on throughput above a forecast of 6000 TJ/year for the Tubridgi Pipeline System would correspond to a increase in annual revenue of only approximately $400,000, assuming the increase attracts a Reference Tariff of about $0.229/GJ.[27] The Regulator does not consider this sufficient to cover the costs of revising the Access Arrangement and provide a sufficient flow on of benefits to Users, nor to provide an adequate incentive for the Tubridgi Parties to increase throughput.

For the purposes of specifying an excess of realised throughput over forecast throughput that could be used to trigger a review of the Access Arrangement, the Regulator has arbitrarily assumed that an increase in revenue of $1 million is appropriate to provide an incentive for the Tubridgi Parties to increase throughput, to cover the costs of review of the Access Arrangement should a review be triggered, and to provide for a sufficient flow on of benefits to Users through reduced tariffs.[28] Assuming an average tariff equal to the Reference Tariff of $0.229/GJ, this corresponds to an increase in throughput quantity of about 5,000 TJ/year.

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[25] Refer to section 5.9.4 of this Draft Decision for a discussion of throughput forecasts.

[26] For example, ACCC (September 1999) Draft Decision for the Central West Pipeline; IPART (October 1999) Draft Decision for the AGL Gas Network; Western Australian Independent Gas Access Regulator (June 2000) Final Decision for the Mid West and South West Gas Distribution Systems.

[27] Refer to section 5.9.4 of this Draft Decision for a discussion of the Reference Tariff.

[28] The Regulator notes that the underlying purpose of a trigger event based on realised throughput quantity is to ensure a sharing between a Service Provider and Users of the benefits of increased revenues and profits, above some threshold level. Given this, a trigger event based on revenue may be more appropriate. However, a trigger event based on quantity has the advantages of being more readily observable, and being observable at an

The Regulator is of the view that, should a trigger event based on realised throughput be maintained in the Access Arrangement, that this should be based on an excess of realised throughput over forecast throughput in the order of 5000 TJ/annum. The Regulator notes that a trigger mechanism on throughput quantity should relate to total realised throughput of this pipeline system, rather than just realised throughput for Reference Services. Provision of a trigger mechanism for review of the Access Arrangement forms part of an incentive mechanism for the Tubridgi Parties to increase the size of the market for gas transmission. That is, an incentive for the Tubridgi Parties to increase the sales of transmission services is provided by the ability to capture windfall profits from increases in quantities of gas transmitted up to the level at which a review of the Access Arrangement is triggered. The design of such a mechanism should be consistent with the objectives for an incentive mechanism set out in section 8.46 of the Code, including that the incentive mechanism should provide the Service Provider with an incentive to increase the volume of sales of all services, but to avoid providing an artificial incentive to favour the sale of one service over another Section 8.46(a). With a view to meeting this objective, the Regulator notes that a trigger event based on total throughput through the pipeline system is required, rather than throughput under the Reference Service alone. Otherwise, an incentive would be created for the Tubridgi Parties to provide Non-Reference Services rather than Reference Services so as to avoid a review of the Access Arrangement and a likely reduction in Reference Tariffs.

The Regulator also notes, however, that there may be more appropriate mechanisms than a trigger event based on throughput quantity to accommodate uncertainty in throughput forecasts, in particular provision for rebates to be paid to Users from revenue in excess of some threshold above forecast revenue. This is further discussed in section 5.10 of this report in relation to Incentive Mechanisms.

Amendment 31
If a provision is maintained in the Access Arrangement for a review to be triggered where an excess of realised gas throughput over forecast gas throughput occurs, clause 9.3 of the Access Arrangement should be amended to specify that the Tubridgi Parties will submit revisions of the Access Arrangement to the Regulator if the independent report on forecast demand for the Tubridgi Pipeline System (to be completed by 31 March 2002), identifies that annual demand for the Tubridgi Pipeline System in 2003/04 or 2004/05 is likely to exceed, by 5000 TJ or more for either year, the forecast throughput used to determine the Reference Tariff.

Revisions to Account for Redundant Capital

- Office of Energy

The Office of Energy submits that the Regulator should consider including in the Access Arrangement a trigger mechanism whereby the Tubridgi Parties must submit revisions to the initial Access Arrangement at the time the Tubridgi Pipeline ceases to contribute to the Services of the Tubridgi Pipeline System (which the Tubridgi Parties suggest is likely to occur in late 2001). Given recent indications that industry may be interested in developing an industrial gas quality pipeline from the North West Shelf to the South West of the State, the trigger mechanism may require the Tubridgi Parties to submit revisions to the Access Arrangement only in the event that known additional demand for the services of the Tubridgi Pipeline System is unlikely to

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earlier date. On this basis, the Regulator has decided to use a trigger event based on quantity for the current Access Arrangement Period.

exceed the nominal capacity of the Griffin Pipeline in the period leading to 1 July 2005. The Office of Energy understands that given the current gas quality specification applying to the DBNGP, the Macedon gas field is unlikely to be developed before that date. This is subject to the possible development of an industrial quality gas pipeline.

The Regulator contemplated the issue of redundant assets in assigning a value to the Initial Capital Base, as discussed in section 5.3.4 of this Draft Decision. The low level of current and forecast use of assets relative to the maximum capacity of the Tubridgi Pipeline System provides some justification for reducing the value of the Capital Base in view of redundancy of particular assets or a proportion of pipeline capacity and hence asset value. In determining an appropriate mechanism for accommodating asset redundancy in the valuation of the Capital Base, the Regulator considered the potential impacts on charges for gas transmission, and hence on the Service Provider and Users of the pipeline system. A reasonable balance of interests of the Service Provider and Users was considered to be achieved through delaying consideration of asset redundancy until the end of the Access Arrangement Period.

The Regulator has some concerns in regard to incorporating a trigger mechanism in an Access Arrangement relating to the redundancy of particular assets, such as one of the pipelines making up the Tubridgi Pipeline System. Reducing the Capital Base to reflect redundancy of particular assets would have the effect of reducing revenue to the Service Provider. Consequently, the Service Provider may have a strong incentive to keep utilising certain assets to avoid the assets being made redundant, despite this possibly being contrary to the efficient provision of services.

4.8.4 Additional Considerations of the Regulator

The Regulator has considered two matters in addition to those raised by public submissions: the timing of the revisions submission date, and additional trigger mechanisms for the Regulator to initiate a review of the Access Arrangement.

Revisions Submission Date

The Tubridgi Parties have proposed a Revisions Submission Date of 1 January 2004 and a Revisions Commencement Date of 1 July 2004. In view of regulatory experience throughout Australia, the Regulator is of the opinion that a six month period is inadequate for assessment of a proposed Access Arrangement and will require that the Revisions Submission Date be brought forward to allow a nine month period for assessment.

The following amendment is required before the Access Arrangement will be approved.

Amendment 32 Clause 9.1 of the Access Arrangement should be amended to provide for a Revisions Submission Date of 1 October 2003.

Trigger Mechanisms

In addition to uncertainty over demand for services (addressed above in relation to public submissions), the Regulator considers that, in principle, it would be generally appropriate for a review of an Access Arrangement to be triggered if significant reductions to the Service Provider's costs occur as a result of regulatory or taxation changes. However, in the case of the Tubridgi Pipeline, with operating costs of only $400,000 per annum, it is very unlikely that any regulatory or taxation changes would occur to give rise to cost savings that would exceed the costs of reviewing the Access Arrangement with any significant residual benefit to be passed on to Users through lower tariffs. As a result, the Regulator does not consider that a trigger event based on regulatory or taxation changes is warranted for the Tubridgi Pipeline System.

5 REFERENCE TARIFF

5.1 INTRODUCTION

Section 3.3 of the Code requires that an Access Arrangement include a Reference Tariff for:

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

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

The principles used to determine Reference Tariffs are to be stated as a Reference Tariff Policy. Both the Reference Tariff Policy and the Reference Tariffs should be designed with a view to achieving the objectives set out in section 8.1 of the Code:

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

The Tubridgi Parties have proposed a Reference Tariff for the Haulage Reference Service. In accordance with the principles established by the Code, the Tubridgi Parties used a price path methodology for the determination of the Reference Tariffs. With this approach, a Reference Tariff is determined in advance for the Access Arrangement Period. The Reference Tariff follows a path that is forecast to deliver a revenue stream sufficient to cover projected costs of providing the services, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period.

The Code provides a general procedure for the application of the price path methodology to the determination of Reference Tariffs. The steps in this general procedure are:

- estimation of an Initial Capital Base;
- estimation of Capital Expenditure;
- estimation of Non-Capital Costs;
- estimation of an appropriate Rate of Return;

- specification of a Depreciation Schedule;
- determination of Total Revenue;
- determination of a cost/revenue allocation across services;
- determination of Reference Tariffs; and
- specification of Incentive Mechanisms.

This chapter provides an assessment of compliance of the proposed Reference Tariff with the requirements of the Code. This is undertaken by examining the general methodology used by the Tubridgi Parties in determining Reference Tariffs and individual parameters of the related financial analysis, taking into account the requirements of the Code and submissions from interested parties.

5.2 METHODOLOGY USED TO DETERMINE REFERENCE TARIFFS

5.2.1 Access Code Requirements

Section 8.3 of the Code provides for the methodology for determination of Reference Tariffs to be at the discretion of the Service Provider, subject to the Regulator being satisfied that the methodology is consistent with the objectives contained in section 8.1 of the Code. Notwithstanding this, section 8.3 of the Code states that Reference Tariffs may be determined by:

(a) a price path approach, whereby a series of Reference Tariffs are determined in advance for the Access Arrangement Period to follow a path that is forecast to deliver a revenue stream calculated consistently with the principles in section 8 of the Code, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period;

(b) a cost of service approach, whereby the Tariff is set on the basis of the anticipated costs of providing the Reference Service and is adjusted continuously in light of actual outcomes (such as sales volumes and actual costs) to ensure that the Tariff recovers the actual costs of providing the Service; or

(c) variations or combinations of these approaches.

5.2.2 Access Arrangement Proposal

The Tubridgi Parties utilised a price path approach for determination of the Reference Tariff.

5.2.3 Submissions from Interested Parties

No submissions were received that addressed the choice of a price path approach by the Tubridgi Parties for the determination of the Reference Tariff.

5.2.4 Additional Considerations of the Regulator

The Regulator recognises that the Code provides a Service Provider with discretion in determining the methodology used to determine Reference Tariffs, subject to the chosen methodology being consistent with the objectives of section 8.1 of the Code. The adoption by the Tubridgi Parties of a price path methodology is consistent with these requirements.

The Access Arrangement is therefore considered to meet the requirements of the Code in respect of the general methodology used for determination of the Reference Tariff. This does not imply, however, that the methodology has been applied to the determination of the Reference Tariff either appropriately or with the required degree of technical rigour and substantiation. These matters are addressed in the following sections of this chapter.

5.3 INITIAL CAPITAL BASE

5.3.1 Access Code Requirements

Sections 8.10 and 8.11 of the Code state the principles for establishing the Initial Capital Base for an existing covered pipeline when a Reference Tariff is first proposed for a Reference Service. These principles apply to the Access Arrangement for the Tubridgi Pipeline System.

Section 8.10 of the Code requires that a range of factors be considered in establishing the Initial Capital Base. These factors are described in more detail below, but relate generally to comparative analysis of different valuation techniques and the reasonable expectations of interested parties.

Section 8.11 of the Code states that the Initial Capital Base for a covered pipeline that was in existence at the commencement of the Code normally should not fall outside the range bounded by the Depreciated Actual Cost (DAC)[29] of pipeline assets and a Depreciated Optimised Replacement Cost (DORC) for the assets.

5.3.2 Access Arrangement Proposal

The Tubridgi Parties determination of the Initial Capital Base of the Tubridgi Pipeline System is described in clause 4.1.1 of the Access Arrangement Information and Appendix B of the Access Arrangement Information.

The Tubridgi Parties adopted a DORC methodology as the primary basis for the determination of the Initial Capital Base for the Tubridgi Pipeline System. The arguments put forward for using this methodology were as follows.

[29] The term "Depreciated Actual Cost" is here given the meaning of section 8.10(a) of the Code as "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".

- The methodology is explicitly recognised in section 8 of the Code and has been accepted as an appropriate valuation methodology in regulatory decisions on other gas transmission pipelines in Australia.

- A DORC valuation reflects the economic cost of providing services and will ensure that tariffs are set at efficient levels and will reflect long term market equilibria.

- A DORC valuation is consistent with the asset value that would apply to any efficient new entrant to the market and its new pipelines.

- A DORC valuation methodology allows the benefits of technological improvements to be transferred to Users.

- A DORC valuation methodology ensures that non-optimal assets are not included in the asset base and are not paid for by Users.

- A DORC valuation methodology values all assets on a consistent basis, regardless of the operating and accounting policies applying at the time they were constructed.

- A DORC valuation provides a fair and appropriate basis on which to allocate costs amongst Users and avoids rate shocks when assets are replaced.

- A DORC valuation provides the appropriate base upon which to add New Facilities Investment and subsequently depreciate it.

The Tubridgi Parties calculated a DORC value on the basis of an optimised replacement cost for replacing the existing Tubridgi Pipeline System with a single pipeline of the same nominal capacity of the two existing pipelines (120 TJ/day). The DORC was calculated by straight-line depreciation of optimised replacement cost values for different asset classes assuming all assets were constructed in 1993 and total asset lives of:

- transmission pipeline – 80 years;

- metering and regulation stations – 50 years; and

- SCADA and communication assets – 15 years.

The optimised replacement cost value of the Tubridgi Pipeline System was estimated by the Tubridgi Parties to be $26.092 million and the DORC value to be 23.755 million.

5.3.3 Submissions from Interested Parties

Depreciated Actual Cost

- Office of Energy

  The Tubridgi Parties have stated that assuming a useful economic life of 80 years for both pipelines, depreciating the actual construction cost of the Tubridgi Pipeline System produces a Depreciated Actual Cost (DAC) figure of $22.57 million as at 1 July 1999. The Office of Energy considers the Regulator should request additional information on how the DAC value was derived. The Office of Energy suggests that the Regulator consider whether adopting the DAC value would be more appropriate in the case of the Tubridgi Pipeline System given it incorporates relatively new assets.

- BHP Petroleum Pty Ltd

  The information provided is insufficient to determine the validity of the DAC valuation. The Regulator should seek sufficient information to enable it to form the view that the DAC valuation is the actual cost of the pipeline.

- BHP Petroleum Pty Ltd

  The calculation of the Initial Capital Base is based on a DORC methodology with little consideration given to other approaches outlined in section 8.10 of the Code.

  The Code specifically requires that for an existing pipeline the service Provider consider the "…accumulated depreciation for those assets charged to Users (or thought to be charged to Users) prior to the commencement of the code" (8.10(a)) and "…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" (8.10(f)). As the pipeline system was built for the Tubridgi and Griffin fields, both of which had a relatively short life compared with the potential physical life of the pipeline it is appropriate for the Proposed Arrangement to consider past charges to existing Users. The owners and financiers of pipeline system will have required a revenue stream consistent with the projected life of the Griffin and Tubridgi gas fields at the time they were commissioned. The Service Provider appears to have calculated the Initial Capital Base assuming an economic life of 80 years. There is no indication that past charges have been considered in this calculation. The Regulator should be satisfied that value of past charges to Users is appropriately incorporated into the calculation of the Initial Capital Base.

The Regulator's considerations in respect of the DAC value of the Tubridgi Pipeline System are discussed below under "Additional Considerations of the Regulator". The Tubridgi Parties have not provided information on the actual cost of the Tubridgi Pipeline System nor the past depreciation of the pipeline assets. An estimate of the DAC value of the assets was provided that was purportedly derived by straight-line depreciation of the actual cost of assets according to assumed asset lives for the pipeline assets, giving a value of $22.57 million (clause 4.1.1.1 of the Access Arrangement Information). This value does not, however, correspond to the concept of Depreciated Actual Cost as described in section 8.10(a) of the Code, which relates to <u>actual</u> depreciation of the assets and corresponds to the "written down" or "book" value of the assets.

The Regulator did not seek to investigate and determine the actual DAC value of the Tubridgi Pipeline System, considering that the cost and time requirement for such investigations were not justified in this particular case. The Regulator did, however, make estimates of the DAC value under assumptions relating to the initial construction cost of the pipeline assets and past depreciation. The DAC value would be highly dependent upon assumptions as to the past depreciation of the pipeline assets. Assuming that accelerated depreciation over an asset life of 26.5 years would have been applied to the assets in the time since construction (consistent with the Tubridgi Parties' specification of a forward-looking depreciation schedule over the Access Arrangement Period), estimated DAC values were in the range $9.4 million to $16.7 million, depending upon the method of depreciation applied. The Regulator notes that the actual DAC value may be lower than this amount if historical depreciation has actually been undertaken on the basis of a shorter economic life of assets.

Depreciated Optimised Replacement Cost

- Western Power

  In determining an asset value the Tubridgi Parties have opted to use DORC.

The Tubridgi Pipeline System currently has the capability of delivering 30TJ/day through the Tubridgi Pipeline and 90 TJ/day through the Griffin Pipeline. The forecast demand in section 12.3, of the Information Section shows that the average daily flow rate (TJ) is 31.55 in 98/99 and 31.93 in 99/00, declining thereafter. In valuing the assets for the DORC valuation the Tubridgi Parties have optimised the Tubridgi Pipeline System capacity. This is based on the premise that there will be an increase in future demand and comments from the Minister for Energy who considers that the pipelines may not meet the requirements of gas producers in the Carnarvon Basin once fields such as Macedon (offshore gas) field are developed. This in effect means the optimised system would replace the dual pipeline system with a single 300mm pipeline that is capable of transporting 120 TJ/day.

From these observations Western Power would like further investigation into the basis for valuing an asset based on its optimised replacement (and potential for future increased use) when the forecast is for declining sales.

- CMS Gas Transmission Australia

The Tubridgi Access Arrangement treats the 10” Griffin pipeline (PL19) and the 6” Tubridgi pipeline as one “virtual” pipeline. CMS does not accept the principle of the notional resizing of physical assets for regulatory purposes nor does CMS accept that this was ever the intent behind the optimisation methodology referred to in the Code.

- BHP Petroleum Pty Ltd

The Initial Capital Base of $22.7 million based on DORC valuation appears to be excessive.

The information provided is insufficient to justify the use of the current system capacity as the optimised system capacity for the purpose of the DORC valuation. While there is scope for growth in the usage of the pipeline, (as reflected in the NCC recommendation and the determination of the WA Minister) the unused capacity in the system is substantial. The present system does not, in our opinion, represent an optimised system. The forecast used in determining the revenue requirement shows significant and increasing unutilised capacity will exist in the system. We would therefore expect the DORC valuation to be significantly lower than the DAC valuation.

The assumption of an 80 year economic life is not justified in the circumstances. We would expect an economic life closer to the expected life of these fields plus some allowance for potential development in the region (as identified in submissions, including the Griffin Parties’ submission regarding the application for revocation of coverage of the Tubridgi Pipeline). We would expect an economic life of between 15 and 20 years. The choice of such a long economic life and the resulting high Initial Capital Base means that the annual amount included as return on capital base used in the calculation of total revenue requirement is excessive.

The choice of DORC based on an 80 year life and without adequate consideration of the historical returns on the pipeline means that the Users will be charged against capital on which the Service Provider has already made some return. In the circumstances we submit that the Regulator should not form the view that the proposed Arrangement complies with the Reference Tariff Principles described in section 8 of the Code.

The Regulator’s considerations in respect of the DORC value of the Tubridgi Pipeline System are discussed below under “Additional Considerations of the Regulator”.

The Tubridgi Parties used a DORC value of $23.755 million as the Initial Capital Base in the determination of Reference Tariffs, based on an optimised replacement cost of assets with a 120 TJ/day service capacity and depreciation over the physical life of the assets.

In assessing the proposed Initial Capital Base the Tubridgi Pipeline System, the Regulator considered the assumptions made by the Tubridgi Parties in deriving the proposed DORC valuation, as well as other DORC valuations based on service capacities of assets of less than 120 TJ/day.

For any DORC valuation, the Regulator considers that it is appropriate to base the valuation on an optimised configuration of a pipeline system to provide for a particular level of service capacity, regardless of the implication that this optimised configuration would comprise a single pipeline rather than two pipelines as currently exist. This approach is based on a view that an optimised replacement cost should be based on a configuration of pipeline assets that would be constructed to provide a given level of service capacity, if those assets were to be constructed at the current time in an efficient manner. The optimised replacement cost should not be based on a replacement of pipeline assets as they currently exist, as such an approach would ignore the possibility that a given level of service capacity could potentially be provided in a more efficient manner. This interpretation of an optimised replacement cost is consistent with the approaches of other Australian gas pipeline regulators.

In assessing the DORC valuation proposed by the Tubridgi Parties, the Regulator investigated the unit rates assumed for the purposes of deriving an optimised replacement cost. The Regulator was concerned that the unit rates assumed by the Tubridgi Parties were high in comparison with historical unit rates for construction of other pipelines, allowing for inflation adjustments and other project-specific corrections. The Regulator revised the optimised replacement cost to reflect lower unit rates of construction, resulting in a revised optimised replacement cost of $22.5 million and a corresponding revised DORC of $20.7 million. The Regulator also estimated DORC values of optimised pipeline configurations with maximum capacities less than 120 TJ/day, reflecting the current low level of utilisation of the pipeline system and the forecast declines in throughput.

The Regulator also assessed the appropriateness of a DORC value of the Initial Capital Base that is based on depreciation over the technical life of the assets. The Regulator has noted that, for the purpose of the Access Arrangement, the Tubridgi Parties have proposed depreciating assets over an economic life that is shorter than the technical life of the principal pipeline assets. There is no reason to presume that the Tubridgi Parties have not depreciated the assets using a similar accelerated depreciation schedule in the past. Applying the same depreciation schedule to depreciating the optimised replacement cost for a 120 TJ/day pipeline gives an asset value of $16.943 million. By virtue of being consistent with a "replacement cost" valuation methodology and likely historical depreciation, the Regulator considers that this value comprises a reasonable balance of interests between the Service Provider and potential Users of the Tubridgi Pipeline System.

Redundant Capital

- Office of Energy

  The Office of Energy agrees that an Initial Capital Base valuation based on the combined capacity of the existing Tubridgi and Griffin Pipelines is appropriate given the expected medium term demand for the total capacity of the Tubridgi Pipeline System.

  However, an argument raised by the Tubridgi Parties in their application to the NCC for revocation of Code coverage in respect of the Tubridgi Pipeline was that it might decommission or abandon the Tubridgi Pipeline after 2001 when the Tubridgi gas field is depleted. In its decision in respect of that application, the WA Minister for Energy considered that Coverage and the development of an Access Arrangement for the Pipeline should not prevent the Tubridgi Parties from either decommissioning or abandoning the Tubridgi Pipeline in the event that in 2001 there is no reasonably foreseeable demand for its services. The Minister also considered that the Access Arrangement may be able to be developed in a way that accommodates the possibility of subsequent re-commissioning of the Tubridgi Pipeline in the event increased demand warrants this.

> Under section 8.27 of the Code the Regulator may require that the Reference Tariff Policy include a mechanism that will, with effect from the commencement of the next Access Arrangement Period, remove an amount from the Capital Base (Redundant Capital) for a Covered Pipeline so as to:
>
> (a) ensure that assets which cease to contribute in anyway to the delivery of Services are not reflected in the Capital Base; and
>
> (b) share costs associated with a decline in the volume of sales of Services provided by means of the Covered Pipeline between the Service Provider and 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 Code criteria.
>
> The Office of Energy submits that the Regulator should also consider requiring that the Reference Tariff Policy include a mechanism that will, with effect from the commencement of the next Access Arrangement Period (which includes the commencement of revisions to the Access Arrangement), remove a specified amount from the Capital Base. The specified amount could either correspond to the capacity of the Tubridgi Pipeline or be proportionate to that part of the capacity of the Tubridgi Pipeline System that at the time of the review is unlikely to be utilised in the short term.

In assessing the value of the Initial Capital Base, the Regulator considered the current and forecast low level of use of the pipeline system and the arguable redundancy of assets or a proportion of assets. These considerations are described below under "Additional Considerations of the Regulator".

The Regulator contemplated three mechanisms for accommodating asset redundancy into valuation of the Capital Base. These mechanisms related to the provisions of the Code dealing with speculative investment and asset redundancy. In determining a means of dealing with asset redundancy, the Regulator consider impacts on the Service Provider and Users, arising from the effects of asset redundancy on the Capital Base and Reference Tariffs. A reasonable balance of interests was considered to be achieved through not considering asset redundancy in the valuation of the Capital Base over the Access Arrangement Period, but requiring the Tubridgi Parties to amend the Access Arrangement to incorporate a redundant Capital Policy (in accordance with section 8.27 of the Code) that will result in a reduction of the Capital Base at the end of the Access Arrangement Period to reflect the level of gas throughput and the use of pipeline assets at that time.

5.3.4 Additional Considerations of the Regulator

Asset Valuation And Economic Principles

Section 8.1 of the Code sets out objectives for the setting of Reference Tariffs:

(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 Services and other services.

The Reference Tariff objectives specified in section 8.1 of the Code would be achieved if Reference Tariffs were set in accordance with a primary consideration of economic efficiency. Efficient tariffs or prices are those that provide signals that motivate an efficient or wealth-maximising allocation of resources to the provision of gas transportation services, and more generally in the economy.

The simplest concept of efficient pricing is that of short-run marginal-cost pricing where an additional unit of output is priced equal to the incremental or marginal costs of production. In this situation, price motivates supply of additional units of a good or service as long as the value placed on the additional units of the good or service exceeds the value of any alternative goods or services for which the resources may be utilised.

For production processes where inputs to production are entirely or predominantly variable with respect to the level of output, short-run marginal-cost pricing is approximately consistent with efficiency in attraction of resources to the production process over the longer term. However, for production processes where inputs to production are predominantly fixed with respect to the level of output, marginal cost pricing would not provide the producing firm with sufficient revenue to meet the costs of these fixed inputs over the longer term. In addition to covering marginal costs of production, efficient prices must also provide for a return to longer-term capital investment in the production process.

The consequence for the regulation of prices of a pipeline owner is that prices should be sufficiently high to assure investors of adequate returns to capital investment and thereby motivate an adequate (i.e. dynamically efficient) level of investment over the longer term. This is despite the fact that in any short term period prices will typically exceed the marginal costs of providing the relevant service.

In practice, the determination of efficient prices can be difficult. The simplest situation for determination of prices is with a new pipeline where prices must be established at a sufficiently high level to motivate an initial level of investment.

Estimation of efficient prices is more complex for an existing pipeline. Continued production of pipeline services will require that prices be at least at a level that provides a return to past capital investment that is sufficient to prevent the fixed inputs being diverted to alternative uses. As the valuation of existing assets under the Code is independent of the valuation of new assets, it would in-principle be possible to value existing assets at scrap value and not affect the incentive for ongoing provision of the service and for new investment. However, valuation of pipeline assets at scrap values would result in low returns to capital that may discourage new investment in pipelines. A more reasonable lower bound on prices is that which would provide a return to the initial investment that would have been sufficient to motivate that investment at the time it occurred, taking into account past returns of capital (via asset depreciation) to investors. This is the rationale for the lower bound value of the Initial Capital Base specified in section 8.11 of the Code, amounting to a DAC valuation.

As an upper bound, prices should not be at a level that motivates excessive investment in pipelines resulting in duplication of infrastructure and substantial under-utilisation of capacity. Prices also should not be so high that Users would be better off if the existing assets were scrapped and replaced with new assets. This is the rationale for the upper bound value of the Initial Capital Base specified in section 8.11 of the Code, being a DORC valuation.

An unambiguous economic determination of efficient prices must take into account requirements for future investment in pipelines and the effects of current regulated prices on the expectations of investors in respect of returns to future investment. While, in principle, the method that is used to value existing assets won't affect future investment, it is likely the Regulator's decisions in relation to existing assets will influence expectations about how the Regulator will exercise discretionary powers of asset valuation in the future. Accordingly, an unduly hash treatment of existing assets may create an expectation that a similar stance may be taken on other matters in the future after new investment has become "sunk" and so may deter new investment. Accordingly, the achievement of dynamic efficiency would appear to require the Regulator to take account of reasonable expectations of asset owners, and strive for a decision that provides for a reasonable balance of interests between the Service Provider and Users.

With uncertain knowledge of future investment requirements and inability to precisely model expectations and investment decisions, such an economic determination is not possible. Consequently, determination of an Initial Capital Base between the bounds of DAC and DORC is largely a matter of judgement by the Regulator. The factors listed for consideration by the Regulator in section 8.10 of the Code are intended to serve as a guide to the Regulator in making this judgement, in addition to the more general principles for setting of Reference Tariffs set out in section 8.1 of the Code.

Factors that the Code Requires to be Considered

The Code requires that the Regulator, in determining the Initial Capital Base, give consideration to the factors set down in sections 8.10(a) to 8.10(k) of the Code. Discussion of these factors in relation to the Tubridgi Parties determination of the Initial Capital Base is undertaken below.

(a) <u>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 (Code section 8.10(a)).</u>

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 is, for the purposes of this Draft Decision, referred to as a Depreciated Actual Cost (DAC).

The Tubridgi Parties have not provided information on the actual cost of the Tubridgi Pipeline System nor the past depreciation of the pipeline assets. An estimate of the DAC value of the assets was provided that was purportedly derived by straight-line depreciation of the actual cost of assets according to assumed asset lives for the pipeline assets, giving a value of $22.57 million (clause 4.1.1.1 of the Access Arrangement Information). This value does not, however, correspond to the concept of Depreciated Actual Cost as described in section 8.10(a) of the Code, which relates to <u>actual</u> depreciation of the assets and roughly corresponds to the “written down” or “book” value of the assets.

In the absence of estimates of the DAC value of the Tubridgi Pipeline System in the Access Arrangement Information, the Regulator has made preliminary estimates of this value under various assumptions of initial construction cost and rates of depreciation.

Information provided in the Access Arrangement documents did not include the initial construction cost of the Tubridgi Pipeline System. The Tubridgi Parties did, however, indicate that the initial construction cost of the assets, depreciated over assumed asset lives, was $22.57 million. Allocation of this amount to asset classes in the same proportions as the DORC value derived by the Tubridgi Parties and backwards calculation from these figure returns a value of $24.79 million as the initial construction cost, assuming asset lives of 80 years for the transmission pipelines, 50 years for meter stations and 15 years for SCADA and communications assets, and an average age for all assets of 6.5 years to 1 July 1999. An initial construction cost of $24.79 million was therefore assumed by the regulator, with a breakdown into different asset categories of:

- transmission pipeline – $21.76 million;
- metering and regulation stations – $2.847 million; and
- SCADA and communication assets – $0.19 million.

The actual depreciation of the pipeline assets since construction was not indicated in information provided by the Tubridgi Parties and hence is unknown by the Regulator. For the purposes of the Access Arrangement, the Tubridgi Parties have proposed using an accelerated depreciation schedule due to uncertainty over future production from the gas fields feeding the pipeline, and hence the effective life of the pipeline assets. This depreciation schedule assumes asset lives of 20 years for the pipeline and meter stations, and 15 years for SCADA and communications assets. While no information was provided on actual historical depreciation, it is reasonable to assume that the Tubridgi Parties would not increase the rate of depreciation of assets solely as a result of the advent of regulation under the Code, and therefore to assume the Tubridgi Parties would have been depreciating the assets at an accelerated rate for accounting and taxation purposes over the period since construction. This presumption is supported by the an indication by the Tubridgi Parties in clause 4.1.3 of the Access Arrangement Information that accelerated depreciation schedule used for the purposes of deriving Reference Tariffs has the advantage of giving rise to tariffs that are aligned with the tolling charge which applies for the existing third party User. This statement implies that the current third party User is already paying tariffs that accommodate accelerated depreciation.

There are several standard methods for calculating depreciation expenses according to an accelerated depreciation schedule. For the purposes of this Draft Decision and estimating a DAC value, two methods allowed for by the Australian Taxation Office[30] were considered:

- the prime cost method, involving straight-line depreciation over an assumed life of the assets that is less than the technical life of those assets;[31] and
- the "diminishing value" or "reducing balance" method.[32]

[30] Australian Taxation Office, *Guide to Depreciation 1998/99*.

[31] Assets are depreciated by a constant absolute amount each year over the assumed life of the asset.

The depreciated values of the initial construction cost determined by these methods are indicated as follows, assuming as asset age of 6.5 years to 1 July 1999. For all calculations, it was assumed that the effective life of the assets is 26.5 years for transmission pipes, 20 years for metering and regulation stations, and 15 years for SCADA and communications assets. These asset lives are consistent with those used by the Tubridgi Parties in deriving a depreciation schedule for the purposes of the Access Arrangement. For the reducing balance methodology, it was assumed by the Regulator that the residual value of assets at the end of their effective lives (ie. scrap value) was 5 percent of the initial construction cost.

Estimated DAC values with different asset depreciation methodologies

Straight-line depreciation	Reducing balance depreciation
$16.71 million	$9.37 million

It is possible that the assets of the Tubridgi Pipeline System have been depreciated at a rate faster than assumed in the above calculations and corresponding to assumed asset lives (for depreciation purposes) of less than 20 years. For example, if depreciation had occurred on the basis of the life of the gas fields as evident in the throughput forecasts provided in the Access Arrangement, then the assume asset lives may have been in the order of 10 years. Such an assumption as to asset lives would result in substantially lower DAC values of $3.6 million by the reducing balance method of depreciation and $8.7 million by the straight line method.

In the absence of further information on actual depreciation of the pipeline assets, the Regulator was unable to determine a definitive DAC value. For the purposes of this Draft decision, the Regulator considered the DAC value to be somewhere in the range $3.6 million to $16.7 million, and that a value of the Initial Capital Base could be set in this range while being consistent with the guidelines established by the Code for the Initial Capital Base to be normally set at greater than the DAC value.

(b) The value that would result from applying the Depreciated Optimised Replacement Cost methodology in valuing the Covered Pipeline (Code section 8.10(b)).

The Tubridgi Parties used a DORC value as the Initial Capital Base in the determination of Reference Tariffs. The estimated DORC value was $23.755 million. The derivation of this value is described in Appendix B of the Access Arrangement Information.

The DORC estimate was made under the principle assumption of replacement of the existing Tubridgi Pipeline System with a single pipeline with the same nominal capacity as the combined total capacity of the Tubridgi Pipeline and Griffin Pipeline. A summary of optimised replacement cost values, assumed asset lives and DORC values for pipeline assets is as follows.

[32] Assets are depreciated at a constant percentage of the residual asset value in each year, with the percentage rate determined so as to return an assumed residual or scrap value of each class of assets at the end of the assumed asset life.

Tubridgi Parties' derivation of a DORC value for the Tubridgi Pipeline System

Asset Category	Optimised Replacement Cost ($million)	Asset Life (years)	Residual Life (years)	DORC ($million)
Transmission Pipe	22.900	80	73.5	21.039
Metering and Regulation Stations	2.989	50	43.5	2.601
SCADA and Communications	0.203	15	8.5	0.115
Total	**26.092**	–	–	**23.755**

In order to assess the validity of the Tubridgi Parties' estimate of the DORC value, technical advice was obtained from Connell Wagner.

Connell Wagner undertook a preliminary assessment of the Tubridgi Parties DORC valuation on the basis of information provided in the Access Arrangement documents and additional cost details provided by the Tubridgi Parties. The assessment involved:

- a critique of unit rates used by the Tubridgi Parties in determining the optimised replacement cost of the Tubridgi Pipeline System, involving replacement of the current two pipelines with a single pipeline with a 120 TJ/day design flow;
- a re-estimation of the optimised cost of a pipeline with a 120 TJ/day design flow, using unit rates deemed more appropriate; and
- consideration of optimised costs of pipelines with capacity less than 120 TJ/day.

Comments on the unit rates used by the Tubridgi Parties to derive the optimised replacement cost for a single pipeline with 120 TJ/day design flow were as follows.

- The pipeline costs (material and construction costs) used by the Tubridgi Parties appear high in comparison with historical unit rates (adjusted for inflation) of other transmission pipelines, including the recently constructed Port Hedland and Goldfields pipelines in Western Australia. Construction costs appear high given the low complexity of the pipeline and the generally favourable ground conditions for pipeline construction in the area of the Tubridgi Pipeline System relative to these other pipelines. The average unit rate used by the Tubridgi Parties of $996/mm/km substantially exceeded the average (inflation adjusted) unit rate for eight other transmission pipelines constructed in Australia between 1989 and 1996 of $760/mm/km. On the basis of this average rate, and allowing for corrections to reflect factors of location and the short length of the Tubridgi Pipeline, Connell Wagner estimated a unit rate of $860/mm/km for the entire pipeline system to be more appropriate.
- The costs of associated plant, such as meter stations, were derived as inflation-adjusted historical costs for the Griffin Pipeline. This was regarded as a reasonable assumption.

- SCADA and communication costs were based on inflation-adjusted historical costs for the Griffin Pipeline, but deflated by 13.5 percent in line with industry practice reflecting advances in equipment capability. This was regarded as a reasonable assumption.

- There was no basis to critique allowances made for environmental and indigenous issues, but the amount of these costs was noted to be relatively small in the total costs of pipeline construction.

The Access Arrangement documentation and additional information provided by the Tubridgi Parties in relation to the DORC valuation did not provide justification for the relatively high unit rate for pipeline construction used in the valuation. On the basis of a revised pipeline construction unit rate of $860/mm/km, Connell Wagner estimated the optimised replacement cost of the Tubridgi Pipeline System with a single pipeline of 120 TJ/day design flow to be $22.5 million, as compared with $26.1 million proposed by the Tubridgi Parties.

A further factor to consider in the derivation of an optimised replacement cost is whether the optimised capacity of a replacement pipeline would be 120 TJ/day. Although information provided in the Access Arrangement Information indicated a possibility that the Tubridgi Pipeline System may be used at capacity at some time in the future, no information is available indicating that this is other than a possibility dependent upon development of new gas fields and a supply of gas suitable to be transported in either the DBNGP or a second pipeline to the south west of Western Australia. In view of the uncertainty over future demand for the pipeline services, two alternative pipeline configurations were considered:

- a single 8 inch pipeline with a nominal capacity of 58 TJ/day; and

- a single 6 inch pipeline with a nominal capacity of 29 TJ/day.

Connell Wagner estimated the construction costs for these two pipeline configurations on the basis of relative reductions to the cost of the 12 inch pipeline (for a 120 TJ/day design flow) of 30.5 percent for the 8 inch pipeline and 46.5 percent for the 6 inch pipeline. The resultant cost estimates were $15.7 million and $12.1 million, respectively.

A DORC value is derived by depreciating the optimised replacement cost taking into account the age and expected life of the assets. In deriving a DORC value, the Tubridgi Parties assumed asset lives equal to the technical lives of the assets, equal to 80 years for the pipeline, 20 years for meter stations and 15 years for SCADA and communications assets. The DORC values for alternative pipeline configurations and optimised replacement cost values, consistent with these assumed asset lives and an average age of assets of 6.5 years to 1 July 1999, are as follows.

DORC valuations of the Tubridgi Pipeline System with straight line depreciation over technical asset lives ($million as at 1 July 1999)

Source of Cost Estimate	Tubridgi Parties	Connell Wagner	Connell Wagner	Connell Wagner
Replacement pipeline capacity	**120 TJ/day**	**120 TJ/day**	**58 TJ/day**	**29 TJ/day**
Optimised replacement cost				
Transmission Pipe	22.900	19.308	12.792	9.491
Metering and Regulation Stations	2.989	2.989	2.705	2.406
SCADA and Communications	0.203	0.203	0.203	0.203
Total	26.092	22.500	15.700	12.100
DORC				
Transmission Pipe	21.039	17.739	11.753	8.720
Metering and Regulation Stations	2.746	2.746	2.485	2.211
SCADA and Communications	0.187	0.187	0.187	0.187
Total	23.972	20.672	14.424	11.117

The assumptions made by the Tubridgi Parties as to asset lives for depreciation of the optimised replacement cost to derive a DORC value are inconsistent with the assumptions made in specification of a Depreciation Schedule for the assets (refer to section 4.1.3 of the Access Arrangement Information and section 5.7 of this Draft Decision). The asset lives implicit in the Depreciation Schedule are:

- transmission pipeline – 20 years;
- metering and regulation stations – 20 years; and
- SCADA and communication assets – 15 years.

These asset lives are consistent with a presumption of depreciation over an economic life of 20 years for principal pipeline assets rather than technical life.

Given the Tubridgi Parties proposal in respect of asset depreciation, the Regulator also considered an asset valuation determined by depreciation of the optimised replacement cost by a straight line methodology over the assumed economic lives of assets. The asset values derived from different estimates of optimised replacement cost are as follows.

Asset valuations of the Tubridgi Pipeline System determined by depreciation of optimised replacement cost over economic lives of assets ($million as at 1 July 1999)

Source of Cost Estimate	Tubridgi Parties	Connell Wagner	Connell Wagner	Connell Wagner
Replacement pipeline capacity	**120 TJ/day**	**120 TJ/day**	**58 TJ/day**	**29 TJ/day**
Optimised replacement cost				
Transmission Pipe	22.900	19.308	12.792	9.491
Metering and Regulation Stations	2.989	2.989	2.705	2.406
SCADA and Communications	0.203	0.203	0.203	0.203
Total	26.092	22.500	15.700	12.100
Depreciated values				
Transmission Pipe	15.458	14.572	9.654	7.163
Metering and Regulation Stations	2.018	2.256	2.042	1.816
SCADA and Communications	0.137	0.115	0.115	0.115
Total	17.612	16.943	11.811	9.094

(c) The value that would result from applying other well recognised asset valuation methodologies in valuing the Covered Pipeline (Code section 8.10(c)).

The Regulator did not consider asset valuation methodologies other than the DAC and DORC valuations as described above.

(d) The advantages and disadvantages of each valuation methodology applied under paragraphs (a), (b) and (c) (Code section 8.10(d)).

A summary of estimated values of the Initial Capital Base using different valuation methodologies is as follows.

Valuations of the Initial Capital Base under different valuation methodologies (values as of 1 July 1999)

Valuation Methodology	Initial Capital Base
DORC valuation (Tubridgi Parties) with straight-line asset depreciation for 80 year pipeline life.	$23.755 million
Optimised replacement cost of 120 TJ/day pipeline valuation (Tubridgi Parties) with straight-line asset depreciation for 26.5 year pipeline life	$19.654 million
DORC of 120 TJ/day pipeline valuation (Connell Wagner) with straight-line asset depreciation for 80 year pipeline life	$20.672 million
Optimised replacement cost of 120 TJ/day pipeline valuation (Connell Wagner) with straight-line asset depreciation for 26.5 year pipeline life	$16.943 million
DORC of 58 TJ/day pipeline valuation (Connell Wagner) with straight-line asset depreciation for 80 year pipeline life	$14.424 million
Optimised replacement cost of 58 TJ/day pipeline valuation (Connell Wagner) with straight-line asset depreciation for 26.5 year pipeline life	$11.811 million
DORC of 29 TJ/day pipeline valuation (Connell Wagner) with straight-line asset depreciation for 80 year pipeline life	$11.117 million
Optimised replacement cost of 29 TJ/day pipeline valuation (Connell Wagner) with straight-line asset depreciation for 26.5 year pipeline life	$9.094 million
Estimated DAC valuation assuming straight-line asset depreciation for 80 year pipeline life	$22.57 million
Estimated DAC valuation assuming straight-line asset depreciation for 26.5 year pipeline life	$16.713 million
Estimated DAC valuation assuming reducing-balance asset depreciation for 26.5 year pipeline life	$9.370 million
Estimated DAC valuation assuming straight-line asset depreciation for 10 year pipeline life	$8.7 million
Estimated DAC valuation assuming reducing-balance asset depreciation for 10 year pipeline life	$3.6 million

Advantages and Disadvantages of a DORC Valuation of the Initial Capital Base

The Tubridgi Parties cited several reasons supporting an argument that a DORC valuation is the most appropriate basis for valuing the Initial Capital Base of the Tubridgi Pipeline System. These are examined as follows.

Firstly, the Tubridgi Parties argue that a DORC valuation approach is appropriate as it is explicitly recognised in section 8 of the Code and has been adopted in a number of regulatory decisions to date.

Section 8.11 of the Code explicitly recognises a DORC valuation of assets, but only in the context that the Initial Capital Base for covered pipelines that were in existence at the commencement of the Code should not normally be greater than a DORC value. The Code does not in any way imply that a DORC value should be used for the Initial Capital Base.

DORC valuations have been considered in arriving at an Initial Capital Base for several other regulated pipelines and other regulated infrastructure in Australia, as summarised below.

Australian regulatory decisions for determining Initial Capital Base values for gas transmission pipelines and distribution systems

Regulatory Agency	Pipeline or Distribution System	Basis for Valuation of the Initial Capital Base
Final Decisions		
ACCC	Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd transmission systems (Victoria) (October 1998)	DORC value, adjusted downward by approximately 2.8 percent to avoid tariff increases.
ORG	Multinet, Westar and Stratus distribution systems (Victoria)	DORC value, adjusted downwards by between zero and 8 percent for different parts of the distribution systems in order to avoid tariff increases.
IPART	Albury Gas Company Limited (July 1999)	DORC value, adjusted downwards by approximately 7 percent to avoid network price differentials.
WA Gas Access Regulator	AlintaGas Mid-West and South-West Distribution Systems (June 2000)	Value determined consistent with returning Reference Tariffs and a Total Revenue that equate to an a priori revenue forecast for the distribution systems. The value is approximately 75 percent of DORC.
Draft Decisions		
ACCC	AGL Pipelines (NSW) Pty Ltd Central West Pipeline (September 1999)	DORC value (but nominally equivalent to the DAC value as this is a new pipeline – 12 months old at the time of valuation)
IPART	AGL Gas Network Limited Natural Gas System in NSW (October 1999)	Value determined at an approximate mid point between DAC and DORC values on the basis of impacts on tariffs and a balancing of interests between the Service Provider and Users. Value is approximately 75 percent of DORC and 150 percent of DAC.
IPART	Great Southern Energy Gas Networks Pty Limited (NSW) (September 1998)	Value determined between DAC and DORC values on the basis of impacts on tariffs and a balancing of interests between the Service Provider and Users. The value is approximately 82 percent of DORC and 188 percent of DAC.
WA Gas Access Regulator	Parmelia Pipeline (Western Australia) (October 1998)	Value determined based on the economic value of the pipeline, impacts on tariffs and a balancing of interests between the Service Provider and Users, and subject to a Redundant Capital Policy that will see the value reduced if forecast market growth does not eventuate. The value is approximately 95 percent of DORC.

Australian regulatory decisions for determining Initial Capital Base values for gas transmission pipelines and distribution systems

Regulatory Agency	Pipeline or Distribution System	Basis for Valuation of the Initial Capital Base
South Australian Independent Pricing and Access Regulator	South Australian Distribution Systems	DORC valuation as submitted by the Service Provider, corrected for a redundant capital allowance.

Regulatory decisions have most commonly derived Capital Base values through a methodology whereby initial DORC values are reduced in accordance with criteria based on a balancing of interests of the Service Provider and Users. For the most part, the criteria for a balance of interests has been that regulated tariffs should not exceed existing tariffs. The recent draft decision by IPART on the AGL Gas Network Limited Natural Gas System in NSW (October 1999) adopted a more stringent criteria that took into account financial outcomes for the Service Provider and a real reduction in tariffs. Derivation of a Capital Base value from a DORC valuation has commonly been used due to the ability to derive disaggregated asset values from the DORC valuations of asset classes.

Secondly, the Tubridgi Parties indicate that a DORC valuation of the Initial Capital Base reflects the economic cost of providing pipeline services and hence ensures that tariffs are set at efficient levels and will reflect long-term market equilibria. In addition, the Tubridgi Parties are of the view that a DORC value is consistent with the valuation methodology that would apply to any efficient new entrant and its new pipelines.

This reasoning would suggest that tariffs based on a DORC valuation of the Capital Base replicate the tariff outcomes of a competitive market, and result in tariffs becoming established at minimum sustainable levels over the long term. This has some credibility in so far as tariffs based on an Initial Capital Base that is greater than the DORC value can be considered to include monopoly rents. However, under the provisions of the Code relating to the treatment of capital assets, a regulated firm will, over the long term, have a regulatory Capital Base valued at an inflation-adjusted Depreciated Actual Cost. Regardless of the methodology used to derive an initial value for the Capital Base, once the original assets are fully depreciated the Capital Base will comprise only assets purchased after commencement of regulation. The Code provides for a return on these assets only on the basis of the written-down actual cost, equivalent to an inflation-adjusted DAC value. Initial valuation of the Capital Base at a value greater than DAC may, depending upon inflation effects, provide windfall gains to the Service Provider over the period until these original assets are depreciated.

Thirdly, the Tubridgi Parties have expressed the view that a DORC value has the advantages that it allows the benefits of technological improvements to be transferred to Users, and it ensures that non-optimal assets are excluded from the asset base and are not paid for by Users.

This view has merit in so far as it is possible to determine an optimal asset configuration in determining an optimised replacement cost. However, the Tubridgi Pipeline System is currently operating at substantially less than the capacity of the original assets and no certain prospect of operating at capacity in the foreseeable future. An optimal asset configuration may therefore comprise a pipeline of substantially less capacity than the current pipeline system. Furthermore, while the exclusion of non-optimal assets from the valuation could benefit Users, it could also be regarded as inequitable for the Service Provider that constructed the pipeline. This is because a DORC valuation at a capacity less than that of the existing system may prevent the recovery of the capital investment actually undertaken by the Service Provider.

Fourthly, the Tubridgi Parties have expressed the view that a DORC valuation values all assets on a consistent basis, regardless of the operating and accounting policies applying at the time they were constructed.

A DORC valuation does have the advantages of technical consistency in valuation. However, as alluded to in the previous point, substantial disagreement may arise in determining the appropriate basis for the DORC valuation in terms of the optimal configuration of assets. Also, it is debatable whether there is any advantage of a valuation that is consistent with current operating and accounting policies, over a valuation that is consistent with the operating and accounting practices applying at the time the asset is constructed. It could be regarded as inequitable for the Service Provider to prevent recovery, or the earning of a return on, efficient capital investment under operating and accounting policies in existence at the time of the investment.

Fifthly, the Tubridgi Parties have stated that a DORC value provides a fair and appropriate basis on which to allocate costs amongst Users and avoids rate shocks when assets are replaced.

This argument has little in-principle or practical justification. On an in-principle level, it is difficult to see how Users will be made better off by paying higher tariffs in the present just to avoid a sudden increase in tariffs in the future, when the Users will pay the same future tariffs in any case. In practice, it is unlikely that a gas pipeline and associated assets would be replaced in a single event, or even in a closely spaced sequence of events. The different economic and technical lives of various assets making up a pipeline, and even various parts of the pipeline, would result in replacement being undertaken as multiple events over long periods, and replacement generally subsumed into activities of maintenance and upgrades. An initial setting of tariffs for an existing pipeline with an Initial Capital Base less than a DORC valuation may lead to a necessity of raising tariffs over time, but significant tariff shocks are unlikely.

Finally the Tubridgi Parties have expressed the view that a DORC valuation provides the appropriate base upon which to add New Facilities Investment and subsequently depreciate it.

This view is not consistent with the provisions of the Code relating to New Facilities Investment. The valuation of the Initial Capital Base is irrelevant to the treatment of New Facilities Investment. Regardless of the methodology used to value the Initial Capital Base, any new Facilities Investment is added to the Capital Base, subject to this investment meeting the requirements set out in section 8.16 of the Code. Subsequent depreciation of New Facilities Investment is undertaken according to a depreciation schedule approved by the Regulator and which is not related to the determination of the Initial Capital Base.

Overall, the merit of a DORC valuation of the Initial Capital Base is solely that such a valuation would not, in itself, result in tariffs that are so high as to motivate inefficient duplication of pipeline assets by another Service Provider. This is the reason for establishing a DORC value as an upper limit on the Initial Capital Base. This does not mean, however, that there is any particular reason for valuing the Initial Capital Base at the DORC value as opposed to some value less than DORC.

The principal disadvantage of a DORC valuation of the Initial Capital Base is that should the value so derived exceed the written down value of actual investment in assets (i.e. the DAC value or an inflated actual capital cost), then the resultant tariffs would conceivably provide windfall profits to the Service Provider at the expense of Users. This would occur where the historical depreciation of assets has exceeded the depreciation assumed in calculation of the DORC value. Common practice in calculation of DORC values appears to be to assume straight-line depreciation over the technical life of assets. In practice, Service Providers would tend to depreciate assets by a different depreciation schedule for taxation purposes using an accelerated rate of depreciation. In this situation, DORC values of assets tend to exceed book values of assets.

There are also practical difficulties in arriving at a DORC valuation of assets. A DORC value can, in some circumstances, be highly subjective. This particularly occurs where the asset being valued is operated at less than maximum capacity, such as with the Tubridgi Pipeline System. Given that an optimised replacement cost should generally be the most efficient means of replacing assets to provide a specific level of service, subjective decisions would need to be made as to whether a replacement cost should be based on assets to provide the current level of service, or whether some provision should be made in capacity assumptions for market growth. Questions may be raised in such a situation as to whether it is reasonable to make any provision for future market growth, or whether a proportion of the pipeline capacity may be regarded as redundant or to comprise speculative investment.

Overall, a DORC methodology for valuation of the Capital Base has merit as an upper bound for an asset value, based on the consideration that any higher value may motivate inefficient duplication of the pipeline system. However, determining a relevant DORC value for the Tubridgi Pipeline System is made difficult by the current use of the pipeline at substantially less than capacity and the assets becoming almost redundant over the five year period of the Access Arrangement, although there is some prospect of increased use of the pipeline over the longer term. A lack of information on future use of the Tubridgi Pipeline System makes it unambiguously specify a service capacity on which a DORC value should be based. Consequently, the DORC value nominated by the Tubridgi Parties, which is based on the maximum service capacity of the existing pipelines, can be considered only as a "maximum" upper bound on the value of the Capital Base. It may actually be appropriate to consider a lower service capacity in any optimised replacement cost calculation. This would reduce the DORC valuation.

Advantages and Disadvantages of a DAC Valuation of the Initial Capital Base

An advantage of a DAC valuation is that, given adequate accounting records, a DAC valuation is auditable as it is based on actual past capital expenditure and revenues. Thus there should be little or no argument about the valuation. This is, however, dependent upon adequate records of initial expenditure, historical returns to the capital assets being valued and historical depreciation of the assets being valued. Such records may not exist in some situations, as was found to be the case for gas transmission and distribution systems in Victoria where the current businesses of Service Providers were separated from a larger business and separate records of returns and depreciation had not been maintained for the relevant groups of assets.[33] For these systems, although estimates of DAC values could be made by making certain assumptions as to the attribution of returns to particular assets and depreciation, the resultant estimates were highly sensitive to the assumptions made and the resultant ranges of DAC estimates were too broad to be useful in assigning particular asset values. The Tubridgi Parties have argued that a similar situation exists for the Tubridgi Pipeline System.

A second advantage of a DAC valuation of the Initial Capital Base is that it is calculated from the actual construction cost of the assets and subsequent returns of capital by depreciation. Thus the DAC value arguably reflects the un-recovered capital costs of providing the services. However, a DAC value does not take into account changes in the value of funds and assets as a result of inflation. Investors can reasonably expect returns to capital and returns of capital to maintain value in real terms. By not accounting for inflation, a DAC value tends to reflect an over-estimate of past returns of capital to investors. Correspondingly, returns to capital calculated from a DAC value of the Capital Base would tend to underestimate required real returns on investment. The older the assets, the more biased a DAC value is in representing the real capital cost of the assets due to not accounting for inflation.

Although the DAC to some extent reflects actual capital costs in providing a service, these costs may not reflect the current most efficient means of providing a service due to failure to take into account technological change. From a forward-looking perspective in regulation, a DAC valuation of assets means that Tariffs are not being determined on the basis of efficient capital costs and "best-practice" in provision of services. Also, a DAC value may include value attributable to assets that are redundant or obsolete. Again, the older the assets, the more likely it is that a DAC value will not reflect a forward-looking efficient capital cost of service provision. Indeed, as noted by the Victorian Office of the Regulator General, assigning a value to the Capital Base on the basis of historical costs and returns has little justification in terms of economic theory, which is concerned with creating the incentives for efficient forward-looking decision making rather than unravelling the past.[34]

The disadvantage of a DAC value arising from the failure to account for inflation may be roughly offset by adjustment for inflation. An "inflation adjusted capital cost" or "inflation adjusted historic cost" can be estimated by revaluation of the assets using a broad inflation indicator such as CPI statistics. Such a valuation is still, however, subject to the availability of relevant financial records and has the disadvantage of potentially not reflecting efficient capital costs of service provision.

Regardless of the value that may be ascribed to capital assets in a hypothetical competitive market for gas transportation, a regulated Service Provider will, over the long term, have a regulatory Capital Base valued at approximately the inflation adjusted capital cost. Once the original assets are fully depreciated, the Capital Base will comprise only assets purchased after commencement of regulation. The Code provides for a return on these assets on the basis of an inflated written-down actual cost, minus any value attributable to redundant

[33] Victorian Principal Transmission System and Western Transmission System as described in the Final Decision of the ACCC on the relevant Access Arrangements (1998).

[34] Office of the Regulator General (Victoria), 1998, Final Decision on the Multinet, Westar and Stratus distribution systems.

assets. Valuation of existing assets at an inflation adjusted capital cost is therefore generally consistent with the treatment under the Code of Capital Expenditure that occurs subsequent to commencement of the Access Arrangement.

Conclusions on Alternative Methodologies for Valuation of the Initial Capital Base

The discussion of advantages and disadvantages of different methodologies for valuing the Initial Capital Base of the Tubridgi Pipeline System indicate that neither DAC nor DORC values are an obvious choice as a valuation methodology, although each has potential advantages.

A DORC valuation of the Initial Capital Base has the advantages of being consistent with efficient capital costs of providing services and resulting in tariffs for gas transportation that are not so high as to result in inefficient bypass of existing assets. The primary disadvantage of the DORC valuation is that it may result in over-recovery of the capital costs of providing the service in situations where historical depreciation of assets has occurred at a rate in excess of that assumed for the purposes of estimating the DORC. Hence a DORC valuation may result in windfall gains to the Service Provider and higher costs to end users of gas than can be justified as a reasonable return on investment by the Service Provider.

A DAC valuation has the advantage of being an auditable number that reflects actual capital costs in service provision. However, a DAC value may not be readily estimable if records have not been maintained of costs, returns and depreciation for the particular group of assets being valued, as the Tubridgi Parties claim is the case for the Tubridgi Pipeline System. A DAC value may not represent a reasonable asset value for the Service Provider if no account is made for inflation, nor may it represent a reasonable value to Users if no account is made for redundancy of assets or technological change.

To determine the appropriate methodology for assigning a value to the Initial Capital Base for the Tubridgi Pipeline System, it is necessary to consider the different methodologies in the specific context of the pipeline systems.

Consistent with the guidance provided by the Code, there is not considered to be any reason for valuing the Initial Capital Base at greater than the DORC value or less than the DAC value. In the absence of a unique value of the Initial Capital Base that has some economic justification, the derivation of a value must depend upon a balance between the interests of the Service Provider and Users of the pipeline system. This matter will be examined in the remainder of this chapter.

(e) <u>International best practice of Pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries (Code section 8.10(e)).</u>

The Regulator did not assess international best practice for the purposes of this Draft Decision as no suitable and readily available benchmarks have been identified and the cost of developing such benchmarks was assessed as prohibitive. The Regulator did, however, note that DORC valuations of the Initial Capital Base have generally been used as a "starting point" for valuation of assets by regulatory agencies in Australia. Values of the Initial Capital Base have commonly derived by scaling down DORC values to achieve access tariffs that are considered to represent a reasonable balance of interests between the interests of the Service Provider and Users of the pipelines.

(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 (Code section 8.10(f)).

The Tubridgi Parties have indicated, that at the time of submission of the Access Arrangement, there was only a single third-party User of the Tubridgi Pipeline System. No information was provided by the Tubridgi Parties on how the tariff for this User was determined. Similarly, no information was provided on any explicit or implicit charges paid by the Tubridgi Parties for gas transported on their own behalf.

As discussed above in relation to the estimation of a DAC value for the Tubridgi Pipeline System, no information was provided on the economic depreciation of the pipeline assets although it was implied that the tariff for the third-party User was consistent with a tariff that may occur with the proposed accelerated depreciation of capital assets. For the purposes of considering asset values, the Regulator considered it reasonable to assume that the assets would have been depreciated at least at the rate implicit in the forward-looking Depreciation Schedule proposed by the Tubridgi Parties

(g) The reasonable expectations of persons under the regulatory regime that applied to the Pipeline prior to the commencement of the Code (Code section 8.10(g)).

Prior to the advent of the Gas Pipelines Access (WA) Act 1998 and the Code, access to the Tubridgi Pipeline System was regulated under the *Petroleum Pipelines Act 1969*. Section 21 of the *Petroleum Pipelines Act* provides for the Minister for Minerals and Energy to make a direction for third-party access to be provided and the terms and conditions of access, including tariffs. Beyond this general power, the provisions of the *Petroleum Pipelines Act* do not provide guidance on the nature of any direction made by the Minister, and hence on the detail of regulation of third party access.

In view of the absence of detail in provisions of the *Petroleum Pipelines Act* relating to the regulation of third party access to the Tubridgi Pipeline System, this previous regulatory regime is not considered to be important in respect of shaping expectations of the Tubridgi Parties as to the application of the Code and the determination of the Initial Capital Base.

(h) The impact on the economically efficient utilisation of gas resources (Code section 8.10(h)).

This section of the Code requires the Regulator to consider the effect of asset valuation methodologies on the use of gas resources. In particular, the section requires consideration of whether the valuation methodology is consistent with tariffs that will provide the price signals that are consistent with economic efficiency in the use of these resources. The Victorian Office of the Regulator General has interpreted this requirement as a need to determine whether the valuation methodology that is selected is consistent with providing price signals that give incentives for the development and use of the most efficient source of gas for the relevant market. That is, the asset valuation methodology and gas transportation pricing regime should encourage the development and use of gas sources that minimise the (forward looking) cost of gas exploration, extraction, transportation and supply to end users.[35]

Efficient use of gas vis a vis other energy resources would require that Users of the Tubridgi Pipeline System, and ultimately the end users of gas, should pay at least the avoidable cost of gas transportation, which is the (forward-looking) cost that the Service Provider could avoid by ceasing to provide the service to that customer. This avoidable cost would not include capital costs arising from sunk investment. Consequently, in order to motivate the efficient use of gas, the valuation of the capital base and the allocation of resultant capital costs should be designed to minimise the divergence in gas usage from the efficient levels that would occur if Users paid only the avoidable cost.

The criterion would generally require that the valuation of the Capital Base be as low as possible while still being consistent with providing the signals to investors in gas transmission assets that motivate a longer-term efficient level of investment in gas transmission assets. This may necessitate a treatment of past investment in a similar manner as for new capital investment. That is, valuation of the Initial Capital Base at an inflation adjusted capital cost or inflation adjusted historic cost. Such a valuation was not made for the Tubridgi Pipeline System, but would be greater than the DAC value.

(i) <u>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) (Code section 8.10(i)).</u>

This criterion would generally require that the value of the Initial Capital Base not be so high as to result in Reference Tariffs that motivate inefficient duplication of pipeline infrastructure. An upper bound on the Initial Capital Base of a DORC value is consistent with this requirement.

(j) <u>The price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase (Code section 8.10(j)).</u>

The Access Arrangement Information indicates that a share in the assets of the Tubridgi Pipeline System was traded in 1995 when SAGASCO South East Inc, Boral Energy Petroleum Pty Ltd and Boral Energy Amadeus NL collective acquired a 56.65 percent share of the Tubridgi Joint Venture. However, it is indicated that the acquisition price reflected not only the value of the Tubridgi Pipeline System, but also the value of the available reserves in the Tubridgi gas field. No specific component of the purchase price was attributed to the value of the pipeline system.

(k) <u>Any other factors the Relevant Regulator considers relevant (Code section 8.10(k)).</u>

In determining an appropriate value of the Initial Capital Base, the Regulator also considered the particular status of the Tubridgi Pipeline System, which is that the pipeline system is currently being used at substantially less than capacity. While there is some prospect of higher throughputs in the future, and indeed some prospect of the pipeline system operating

[35] Office of the Regulator General, Victoria, May 1998. Access Arrangements – Multinet Energy Pty Ltd & Multinet (Assets) Pty Ltd, Westar (Gas) Pty Ltd & Westar (Assets) Pty Ltd, Stratus (Gas) Pty Ltd & Stratus Networks (Assets) Pty Ltd, Draft Decision, p65.

at capacity, there is substantial uncertainty as to both future throughputs and the timing of any possible increase. As a consequence of this status, the assets of the pipeline system can be regarded as substantially redundant at the current time, although with some likelihood of future use.

The Code does not explicitly contemplate a situation of redundant assets in regard to valuation of the Initial Capital Base. The Code does, however, address capital redundancy in respect of adjustments to the value of the Capital Base over time. Section 8.27 of the Code provides for a Reference Tariff Policy to include a mechanism for removing an amount from the Capital Base (redundant capital) so as to:

(a) ensure that assets which cease to contribute in any way to the delivery of services are not reflected in the Capital Base; and

(b) share costs associated with a decline in the volume of sales of services provided by means of the pipeline between the Service Provider and Users.

Section 8.28 of the Code provides that if assets that are made redundant subsequently contribute to, or make an enhanced contribution to, the delivery of services, the assets may be treated as a New Facility having New Facilities Investment (for the purposes of sections 8.16, 8.17, 8.18 and 8.19 of the Code) equal to the redundant capital value increased annually on a compounded basis by the Rate of Return from the time the redundant capital value was removed from the Capital Base.

The Regulator has some possible courses of action in recognising redundant assets in ascribing a value to the Capital Base.

Firstly, the Regulator could value the Initial Capital Base under a premise that the pipeline was operating at capacity, and then attribute a portion of this value to a redundant capital account. This methodology is not explicitly contemplated by the Code, but would be consistent with provisions of the Code dealing with revisions to the Capital Base. The methodology would have the advantage of providing for the Tubridgi Parties to receive a rate of return at the current time on a Capital Base that is consistent with the current level of use of the Tubridgi Pipeline System, but would allow for a higher level of use of the assets to be recognised in the value of the Capital Base at a later time if speculated increases in throughput are realised. Furthermore, the provision for re-capture of redundant capital would provide a strong incentive for the Tubridgi Parties to increase gas throughput.

The second possible course of action for the Regulator in addressing the redundancy of assets is to not specifically make provision for redundancy in valuation of the Initial Capital Base, but to make explicit provision for asset redundancy in any subsequent revision of the Access Arrangement, as provided for by sections 8.27 and 8.28 of the Code. This methodology would effectively provide the Tubridgi Parties with a grace period to increase pipeline throughput before any asset redundancy provisions of the Access Arrangement would come into effect. The methodology would have similar incentive properties to the first option in regard to motivating increases in pipeline throughput and asset utilisation, but may result in higher Reference Tariffs in the initial Access Arrangement Period than would occur if asset redundancy was taken into account in valuation of the Initial Capital Base.

The third possible approach is to value the pipeline on the basis of an assumption of a maximum pipeline capacity sufficient to meet projected demand, including any future increased demand that has a reasonable prospect of being realised and that can reasonably be accommodated in determination of Reference Tariffs. The effectiveness of this approach would depend on the certainty with which future demand for pipeline services can be projected.

Conclusion

In contemplating the value of the Initial Capital Base for the Tubridgi Pipeline System, the Regulator considered two principal matters, as follows.

i. For the Tubridgi Pipeline System, there is no reason why the value ascribed to the Initial Capital Base should fall outside of the range contemplated by the Code, that is the range bounded by the values of DAC and DORC.

ii. The Access Arrangement should make provision for asset redundancy to be recognised in the value of the Capital Base, either in the valuation of the Initial Capital Base and/or in subsequent revisions of the Access Arrangement.

Insufficient information was presented in the Access Arrangement Information for the Regulator to definitively estimate a DAC value. The DAC value may be somewhere in the range of a few million dollars to $16.7 million, depending upon past depreciation of the pipeline assets, which is unknown by the Regulator. Depending upon the actual depreciation of pipeline assets (which is unknown by the Regulator).

As a result of uncertainty over future throughput for the Tubridgi Pipeline System and hence difficulty in "optimising" replacement assets, it was not possible to definitively estimate a DORC value. However, considering only the case of a replacement pipeline with a capacity of 120 TJ/day (the capacity of the current pipeline system), the Regulator has estimated the DORC value to be $20.672. This is less than the DORC value proposed by the Tubridgi Parties ($23.755 million) for reason of different assumptions by the Regulator as to unit rates of pipeline construction.

The Regulator has noted that the Tubridgi Parties have proposed depreciating assets over an economic life that is shorter than the technical life of the principal pipeline assets, and that there is no reason to presume that the Tubridgi Parties have not depreciated the assets using a similar accelerated depreciation schedule in the past. Applying the same depreciation schedule to depreciating the optimised replacement cost for a 120 TJ/day pipeline gives an asset value of $16.943 million. By virtue of being consistent with a "replacement cost" valuation methodology and likely historical depreciation, the Regulator considers that this value comprises a reasonable balance of interests between the Service Provider and potential Users of the Tubridgi Pipeline System.

In considering alternative approaches to recognising asset redundancy in the value ascribed to the Capital Base, the Regulator considered impacts of the alternative approaches (and hence values of the Initial Capital Base) on Reference Tariffs and on the Tubridgi Parties. It was noted that a value of the Initial Capital Base of $16.943 million would give rise to Reference Tariffs that are substantially less average charges for gas transportation to the third party User of the pipeline system at the time the Access Arrangement was submitted (approximately $0.50 per GJ of gas transported).

On the basis of the above, the Regulator considers that an appropriate value for the Initial Capital Base is $16.943 million, subject to the Access Arrangement being amended to include an Redundant Capital Policy in accordance with the provisions of section 8.27 of the Code.

On this basis, the value of the Initial Capital Base is as follows.

Regulator's revised Initial Capital Base
(values as at 1 July 1999)

Asset Class	Proposed by the Tubridgi Parties	Revised by the Regulator
Transmission Pipe	$21.039 million	$14.572 million
Metering and Regulation Stations	$2.601 million	$2.256 million
SCADA and Communications	$0.115 million	$0.115 million
Total	**$23.755 million**	**$16.943 million**

The following amendments are required before the Access Arrangement will be approved.

Amendment 33

The Access Arrangement and Access Arrangement Information should be amended to reflect an Initial Capital Base of $16.943 million as at 1 July 1999.

Amendment 34

The Access Arrangement should be amended to include a Redundant Capital Policy that provides for the Capital Base to be reduced at the end of the Access Arrangement in accordance with pipeline throughput and the use of pipeline assets at that time.

5.4 CAPITAL EXPENDITURE

5.4.1 Access Code Requirements

Sections 8.15 to 8.21 of the Code provide for forecast Capital Expenditure on a covered pipeline and associated regulated assets to be incorporated into the Capital Base of the pipeline, and for forecast Capital Expenditure to be considered in determination of Reference Tariffs.

The Capital Base of a covered pipeline may be increased from the commencement of a new Access Arrangement Period to recognise capital costs incurred in constructing New Facilities for the purpose of providing services, subject to the New Facilities Investment meeting certain criteria.

Section 8.16 of the Code sets out criteria that must be met by any New Facilities Investment if the actual capital cost of that investment is to be added to the Capital Base. These criteria are:

(a) the amount of the capital cost does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering services; and

(b) one of the following conditions is satisfied –

i. the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or

ii. the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or

iii. the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

Section 8.17 of the Code sets out two factors that the Regulator must consider in determining whether Capital Expenditure meets the criteria set out in section 8.16:

(a) whether the New Facility exhibits economies of scale or scope and the increments in which Capacity can be added; and

(b) whether the lowest sustainable cost of delivering Services over a reasonable time frame may require the installation of a New Facility with Capacity sufficient to meet forecast sales of Services over that time frame.

Section 8.18 of the Code allows for a Reference Tariff Policy to state that the Service Provider will undertake New Facilities Investment that does not satisfy the requirements of section 8.16, and for the Capital Base to be increased by that part of such investment which does satisfy section 8.16 (the Recoverable Portion). Section 8.19 of the Code allows for an amount of the balance of the investment to be assigned to a Speculative Investment Fund, and to be added to the Capital Base at some future time if the criteria of section 8.16 come to be met. Section 8.19 also sets out the manner in which the value of the Speculative Investment Fund is determined at any time.

Section 8.20 of the Code provides for Reference Tariffs to be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement Period provided that the investment is reasonably expected to pass the requirements of section 8.16 when the investment is forecast to occur. This does not, however, mean that the forecast New Facilities Investment will automatically be added to the Capital Base after it has occurred (section 8.21). Rather, the Regulator will assess whether the investment meets the criteria of section 8.16 of the Code either at the time of review of the Access Arrangement or, if asked to do so by the Service Provider, at the time at which the investment takes place.

Section 8.22 of the Code requires that either the Reference Tariff Policy should describe, or the Regulator shall determine, how the New Facilities Investment is to be determined for the purposes of additions to the Capital Base at the commencement of the subsequent Access Arrangement Period. This includes whether (and how) the Capital Base at the commencement of the next Access Arrangement Period should be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment.

Sections 8.23 to 8.25 of the Code set out provisions for New Facilities Investment to be financed in whole or in part of capital contributions from Users, or from surcharges over and above Reference Tariffs to be levied on Users.

5.4.2 Access Arrangement Proposal

The Tubridgi Parties have forecast a zero level of Capital Expenditure over the term of the Access Arrangement (Access Arrangement clause 4.1.5).

5.4.3 Submissions from Interested Parties

No submissions were received that addressed the forecast of Capital Expenditure.

5.4.4 Additional Considerations of the Regulator

As the Tubridgi Parties have forecast a zero level of Capital Expenditure for the Tubridgi Pipeline, the matter has no relevance to the determination of Reference Tariffs for the Access Arrangement Period.

The Regulator notes that the zero forecast of Capital Expenditure does not negate the possibility of the Tubridgi Parties undertaking New Facilities Investment and rolling this investment into the Capital Base at the time of review of the Access Arrangement, subject to the New Facilities Investment meeting the requirements of section 8.16 of the Code. However, the zero forecast for Capital Expenditure means that the New Facilities Investment would not be reflected in Reference Tariffs during the Access Arrangement Period.

5.5 NON-CAPITAL COSTS

5.5.1 Access Code Requirements

Section 8.36 of the Code defines Non-Capital Costs as the operating, maintenance and other costs incurred in the delivery of a Reference Service.

Section 8.37 of the Code provides for a Reference Tariff to recover all Non-Capital Costs (or forecast Non-Capital Costs, as relevant) except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service.

5.5.2 Access Arrangement Proposal

The Tubridgi Parties' forecast Non-Capital Costs over the term of the Access Arrangement are indicated in section 4.1.4 of the Access Arrangement Information. These costs are divided into categories of:

- overheads;
- operational costs; and
- pipeline marketing costs.

The Access Arrangement Information provides the following forecast of Non-Capital Costs. The values provided are nominal values based on a constant real level of total Non-Capital Costs of $495,000 per annum and an annual inflation rate of 2.5 percent.

Tubridgi Parties' proposed Non-Capital Costs (nominal $thousand)

Cost Category	Year				
	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Overheads	23	24	25	25	25
Operational costs	451	464	475	487	499
Pipeline marketing costs	21	20	21	22	22
Total Non-Capital Costs	495	507	520	534	546

Section 4.1.4.2 of the Access Arrangement Information provides a more detailed breakdown of operational costs into wages and salaries; leasehold licences and rates; contract operations and consultants; and other operating costs.

The forecast Non-Capital Costs do not include costs of system use gas. Section 4.1.4.2 of the Access Arrangement Information states that there is no appreciable gas use/loss incurred in the transportation of gas through the Tubridgi Pipeline System and no system use gas has been forecast. It is proposed that any system use gas that does occur will be provided and funded by the Tubridgi Parties.

5.5.3 Submissions from Interested Parties

- Western Power

  After the year 2001/02, there is no allocation for unregulated Non-Capital Costs for the pipeline system. A more detailed explanation as to why there are no costs past this date is considered appropriate.

Additional information provided to the Regulator by the Tubridgi Parties indicates that the unregulated Non-Capital Costs identified in the Access Arrangement Information relate to production of raw gas from the Tubridgi reservoir and processing of this gas through the Tubridgi gas plant. There are no forecasts of unregulated costs beyond 2001/02 because production from the Tubridgi Reservoir is forecast to cease in 2001/02. It is currently envisaged that, after this time, the Tubridgi Parties sole responsibilities will be in relation to their regulated role as Service Provider for the Tubridgi Pipeline System.

In undertaking an assessment of the Non-Capital Cost forecast of the Tubridgi Parties, the Regulator obtained advice from Connell Wagner who reviewed the cost forecasts on the basis of information provided in the Access Arrangement Information and a more detailed breakdown of costs provided on a confidential basis by the Tubridgi Parties. Connell Wagner indicated to the Regulator that the Non-Capital Costs for the Tubridgi Pipeline System were not derived by allocation of total Non-Capital Costs of the regulated and non-regulated assets. Rather, a zero-based approach was adopted to estimate Non-Capital Costs for the Tubridgi Pipeline System as if no unregulated (ie. gas production) activities took place. In view of this methodology, the cessation of gas production activities in 2001/02 would not affect the forecast Non-Capital Costs for the Tubridgi Pipeline System.

- Office of Energy

  The Regulator should satisfy himself that the forecast Non-Capital Costs for the Tubridgi Pipeline System reflect prevailing industry best practice and that there is a reasonable basis for the forecasts. Further, the Office of Energy considers that the Regulator should verify whether it is reasonable to forecast constant Non-Capital Costs in the context of the Tubridgi Pipeline ceasing to transport gas in late 2001, which has been reflected in the calculation of the Reference Tariffs for that, and later, years.

In assessing the forecasts of Non-Capital Costs made by the Tubridgi Parties, the Regulator obtained advice from Connell-Wagner who reviewed the cost forecasts on the basis of information provided in the Access Arrangement Information and a more detailed breakdown of costs provided on a confidential basis by the Tubridgi Parties. The advice from Connell Wagner and the Regulators Assessment of the forecast Non-Capital Costs is described below under “Additional Considerations of the Regulator”.

In additional information provided to the Regulator, the Tubridgi Parties have argued that the cessation of gas transport through the Tubridgi Pipeline is unlikely to have a material effect on Non-Capital Costs for the following reasons.

- There will be costs associated with maintaining the Tubridgi Pipeline at an operational level, despite the fact that no gas is forecast to flow.

- There are considerable economies of scale and scope associated with maintaining and operating both pipelines. The cost of undertaking these operational activities in respect of one pipeline is expected to be fundamentally the same as undertaking the activities in respect of two pipelines.

- There will be no material effect on overheads or pipeline marketing costs.

Key Performance Indicators

- CMS Gas Transmission Australia

  Key Performance Indicator’s are compared in Table 6 of the Access Arrangement Information. The Tubridgi Access Arrangement concludes that comparisons are “difficult to draw meaningful conclusions from”. CMS concurs with the view that such a simplistic comparison of unit costs is unhelpful, and would further add that such an approach can be potentially misleading as it fails to account for the widely disparate circumstances specific to individual pipelines across Australia, to say nothing of overseas.

In assessing the forecast of Non-Capital Costs, the Regulator considered the usefulness of key performance indicators and concluded that a comparison of Non-Capital Costs across transmission pipelines was, in this instance, of limited value by virtue of the particular characteristics of the Tubridgi Pipeline System including low throughput, short length, and the absence of compression stations. These characteristics make the Tubridgi Pipeline

System substantially different from most other transmission pipelines and complicates comparisons. Rather than assessing the forecast of operating costs by means of key performance indicators, the Regulator considered the "reasonableness" of cost line items. This assessment is described below under "Additional Considerations of the Regulator".

5.5.4 Additional Considerations of the Regulator

In assessing the Tubridgi Parties' forecast of Non-Capital Costs the Regulator obtained advice from Connell Wagner. This advice indicated that, in total, the forecast Non-Capital Costs are within a range that may be expected for the stand-alone operation of the Tubridgi Pipeline System, as was assumed by the Tubridgi Parties in deriving the forecast. This methodology was used despite the operation of the Tubridgi Pipeline System actually being carried out in conjunction with the gas production activities of the Tubridgi Parties.

Connell Wagner did, however, express several concerns as to the forecast of Non-Capital Costs. These concerns and the Regulator's considerations on each matter are as follows.

- The assumption of stand-alone operation of the Tubridgi Pipeline System may result in Non-Capital Costs being over-estimated as a result of ignoring economies of scale and scope gained through operation of the Tubridgi Pipeline System in conjunction with other activities. The Regulator recognises that economies of scope and scale may give rise to cost savings under the current mode of operation of the Tubridgi Pipeline System, but accepts the assumption of stand alone operation in view of the potential application to the Tubridgi Pipeline System of ring fencing provisions of the Code.

- No justification was provided for cost items of "administrative overheads" and "manpower head office", or details of the activities to which the costs relate. Notwithstanding the lack of justification, the Regulator notes that the total cost allocated to these items is in the order of $85,000 which would probably correspond to less than one employee. On this basis, the Regulator considers that the cost is not unreasonable.

- The cost for contract operators of the Tubridgi Pipeline System is based on two full-time, on-site personnel, and is the single largest cost item in Non-Capital Costs. This may be contrary to efficient operating practice for a pipeline system, that may require neither full time attendance of operators, nor for operators to be located on-site as the possibility may exist for operation to occur remotely from Perth. The Regulator concurs that these cost items remain unsubstantiated and may over-estimate the forecast of Non-Capital Costs.

- Costs for gas testing and inspection, distillate and environmental compliance reporting have not been justified by demonstrated requirements for these activities. The Regulator notes, however, that the costs are relatively minor.

The Regulator is satisfied that the assumption of stand-alone operation of the Tubridgi Pipeline System is a reasonable basis for the forecast of Non-Capital Costs in this case and that the total Non-Capital Costs are in a range that may be expected for this mode of operation. The Regulator therefore accepts the forecast of Non-Capital Costs for the purposes of this Draft Decision, but will require further substantiation of costs associated with contract operators to ensure that these costs are consistent with efficient practice in operation of the pipeline system.

The following amendment is required before the Access Arrangement will be approved

> Amendment 35
>
> The Access Arrangement Information should be amended, or additional information provided to the Regulator, to justify the costs of contract operations in terms of demonstration that the forecast costs are consistent with efficient operating practice for the pipeline system.

5.6 RATE OF RETURN

5.6.1 Access Code Requirements

Sections 8.30 and 8.31 of the Code state the principles for establishing the Rate of Return for an existing Covered Pipeline when a Reference Tariff is first proposed for a Reference Service. These principles apply to the current Access Arrangement for the Tubridgi Pipeline System.

Section 8.30 of the Code requires that the Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).

Section 8.31 states that, by way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1 of the Code, as listed in section 5.1 of this Draft Decision.

5.6.2 Access Arrangement Proposal

The Tubridgi Parties utilised a cost-of-service methodology for the determination of Total Revenue and Reference Tariffs, as allowed for by section 8.4 of the Code and discussed in section 5.8 of this Draft Decision. The Rate of Return enters the tariff calculation through calculation of a return on the Capital Base that appears as a cost in the determination of Total Revenue.

The Tubridgi Parties determined a Rate of Return through estimating a Weighted Average Cost of Capital (WACC). The estimation of the WACC is described in section 4.1.2 of the Access Arrangement Information and Appendix A of the Access Arrangement Information.

The WACC value was estimated by the Tubridgi Parties using Capital Asset Pricing Model (CAPM) theory and the following values of input variables, as indicated in Appendix A of the Access Arrangement Information or as interpreted by the Regulator.

Tubridgi Parties' estimation of the rate of return

WACC Calculation Input Variable	Value
Real risk free rate (%)	3.78
Nominal risk free rate (%)	6.37
Inflation forecast (%)	2.5
Cost of debt margin over the nominal risk free rate (%)	1.2
Gearing (debt to equity ratio) (%)	60
Corporate tax rate (%)	36
Dividend imputation factor (gamma)	0.5
Asset beta	0.6
Equity beta	1.3
Debt beta	0.12
Market risk premium (%)	6.0

The WACC was estimated to be in the range 8.01 percent to 9.38 percent (real, pre-tax), with the estimate varying depending upon the approach used to convert a post-tax nominal WACC into a pre-tax real WACC. A value of 8.75 percent was used for the calculation of Total Revenue and the Reference Tariff, with this value selected on the basis of being close to the midpoint of the estimated range.

5.6.3 Submissions from Interested Parties

Risk Free Rate and Inflation

- Office of Energy

> The Tubridgi Parties have not substantiated the method of averaging past bond yields over 2 months in calculating the risk free rate that is proposed. The Capital Asset Pricing Model is a forward looking model and as such it is considered acceptable practice to use a point estimate for the ten year Commonwealth bond or to use an average over a shorter period e.g. 20 business days, as used recently by IPART and supported by the Office of Energy for Western Power's 1998/99 and 1999/00 electricity access pricing re-determinations.
>
> The inflation rate of 2.5% assumed by the Tubridgi Parties is the same as the most recent Commonwealth Treasury forecast of 2.5%. The Regulator may also need to consider the potential impact of the GST on the inflation rate at the relevant time.

The Regulator's considerations in regard to estimates of the inflation rate and risk free rate are described below under "Additional Considerations of the Regulator". The Tubridgi Parties have assumed a nominal risk free rate of 6.37 percent and adopted an inflation rate forecast of 2.5 percent, implying a real risk free rate of 3.78 percent.

To derive updated estimates of the inflation rate and risk free rate, the Regulator used the yield to maturity on 10 year Commonwealth Government Treasury Bonds as a proxy for the nominal risk free rate and the yield to maturity on the 10 year Commonwealth Government

Capital Indexed Treasury Bonds as the proxy for the real risk free rate. The observed yield for the relevant bonds was taken as the average of the 20 trading days to 15 June 2000. This gave a nominal risk free rate of 6.27 percent, a real risk free rate of 3.40 percent, and a forecast rate of inflation of 2.78 percent.

The Regulator did not explicitly consider the impact of the GST on expected inflation rates for the purposes of assessing the Rate of Return.

Cost of Debt

- Office of Energy

  The debt premium, or risk margin, of 1.2% used by Tubridgi is the same as that used in the determination of the Victorian Gas Access Arrangements by the ACCC and ORG. The Office of Energy considers this figure to be reasonable although the Regulator needs to undertake a review of the debt premium being proposed.

The Regulator's assessment of the debt risk margin is described below under "Additional Considerations of the Regulator". In assessing the debt risk margin, the Regulator considered the debt margins adopted by regulators in recent regulatory decisions, generally using a margin of 1.2 percent. The Regulator considers that it is reasonable to assume a debt margin of 1.2 percent for the Tubridgi Pipeline System.

Asset and Equity Beta

- Office of Energy

  The Tubridgi Parties have used an equity beta of 1.3. This is inconsistent with the equity beta used in past Western Australian gas transmission and distribution access arrangements. Also this value is higher than 1.2 used in the determination of the Victorian gas transmission and distribution Access Arrangements. The Regulator needs to review and assess the equity beta being used and whether or not it adequately reflects the riskiness of the business. In this respect it is important to note that the Tubridgi Parties have proposed their Access Arrangement based on the evidence, which suggests that there will be a long-term requirement for gas haulage service on the Tubridgi Pipeline System.

  It is noted that the proposed equity beta has also produced a higher asset beta.

- CMS Gas Transmission Australia

  The Tubridgi Access Arrangement quotes an asset beta of 0.6 and equity beta of 1.3. CMS merely wishes to comment that the continued trend towards acceptance of industry average values for such surrogate measures of risk amounts to acceptance of the principle of cross-subsidy. Users of pipelines which face higher risks benefit from lower tariffs at the expense of not only capital investors, but also at the expense of Users of pipelines (and even distribution networks) which face lower market risks.

- Western Power

  The main concern for Western Power in establishing a proposed rate of return is the equity beta value. The equity beta used by the Tubridgi Parties appears to be an arbitrary figure of 1.3. The Tubridgi Parties have used a debt to equity ratio of 60:40, an asset beta of 0.6 and a tax rate of 36 percent, the corresponding equity beta should be 1.176. It is appreciated that there are other economic and operating risks faced by the pipeline. However, investigation by the Regulator into the variations in both is considered important.

The Regulator's assessment of the equity beta proposed by the Tubridgi Parties is described below under "Additional Considerations of the Regulator". In determining an appropriate equity beta value for the Tubridgi Pipeline System, the Regulator adopted the approach of determine a proxy asset beta, and then re-levering this into an equity beta that is consistent with the assumed capital structure of the entity, using the following expression:

$$b_e = b_a + (b_a - b_d).\frac{D}{E}$$

where b_a is the asset beta, b_d is the debt beta (indicating the sensitivity of the of the Tubridgi Parties' debt (risk premium) to the overall debt market).

In considering appropriate values of the debt beta and asset beta, the Regulator considered the relative riskiness of the Tubridgi Pipeline System in relation to other transmission pipeline and distribution system businesses. The Regulator considers that, as a stand alone business, the Tubridgi Pipeline System would bear a higher level of risk than most other gas transmission businesses for principal reason that the Tubridgi Pipeline System is a small "feeder" pipeline located close to the production end of the gas supply system. As a consequence, there are a limited number of potential Users of the pipeline system, relative to a "downstream" transmission pipeline or distribution system, and the market for services is highly dependent upon production from a limited number of gas fields.

These considerations led to the Regulator assuming an asset beta of 0.65. Taking into account an assumed debt beta of 0.20 and a debt to equity ratio of 60:40, an equity beta of 1.33 was calculated.

Market Risk Premium

- Office of Energy

  The assumed typical market risk premium of 6.0% appears to be consistent with accepted industry values. The Regulator needs to be satisfied that there is wide acceptance of 6.0% as used by the Tubridgi Parties.

The Regulator's assessment of the market risk premium proposed by the Tubridgi Parties is summarised below under "Additional Considerations of the Regulator". Australian regulators have been using an assumed equity premium that is at the lower end of, or below, the range implied by the long-term historical averages. The accepted values of market (equity) risk premiums have been in the range 5 to 6 percent. Having regard to the range in market risk premiums adopted by Australian regulators to date, the Regulator considers that a market risk premium of 6 percent should be used to estimate the WACC for the Tubridgi Pipeline System. This is the same value of the market risk premium as used by the Tubridgi Parties.

Dividend Imputation (Gamma) Factor

- Office of Energy

  The Tubridgi Parties have used a dividend imputation figure, which does not appear to be standard industry practice in Australia. The gamma value for the value of imputation credits used by the Tubridgi Parties is 0.3 or 30%. The Office of Energy does not consider that the Tubridgi Parties have substantiated the use of 30%. The Office of Energy considers that a more appropriate value would be 50%, consistent with the general approach in Australia. This has been the recommended approach for past gas distribution access arrangements in Western Australia and is consistent with recent determinations across Australia, including the ACCC's determination in relation to the Victorian gas transmission Access Arrangements.

The Regulator's assessment of the gamma value proposed by the Tubridgi Parties is summarised below under "Additional Considerations of the Regulator". The principal consideration in respect of the gamma value was the requirement of section 8.31 of the Code that requires the rate of return to reflect standard industry structure, taken to constitute Australian ownership and availability of dividend imputation. In view of this, a gamma value of 0.5 is considered to be reasonable for the Tubridgi Pipeline System.

WACC Calculation and Value

- Western Power

  The calculation of the proposed rate of return, in this case the Weighted Average Cost of Capital estimate, is inconsistent with the recent decision by O*ff*GAR for the Parmelia Pipeline Access Arrangement.

- CMS Gas Transmission Australia

  In calculating WACC, the Tubridgi Access Arrangement uses the approximate midpoint between two transformation methods (the "reverse transform" which yields 8.01% and the "market practice" transform giving 9.38% pre-tax real). CMS notes that it believes the latter practice to be the appropriate methodology, complying with the intent of the Code that regulatory intervention not distort investment decisions and that it should embrace market-based incentives. This approach has been accepted in the Regulator's Draft Decision for the Parmelia Pipeline.

  CMS would also note that the resulting relativity between the WACC values for Parmelia and the Tubridgi pipeline system are an appropriate recognition of the relative levels of commercial risk. However, it is the view of CMS as a proactive investor in the Australian and international energy industry, that the absolute values of regulated returns and the application of the methodology by which these are derived, continues to fall short of a realistic recognition of the commercial factors underlying infrastructure investment decisions. A clear distinction needs to be recognised between what constitutes an acceptable rate of return for pre-existing assets which face future commercial risks but which have already largely realised the benefits for which they were originally intended, and an acceptable risk-adjusted rate of return for an asset which is at the beginning of its intended use.

- BHP Petroleum Pty Ltd

  We note that the WACC of 8.75% used in the calculation is high compared to others and in particular the ORG/ACCC estimate of a WACC of 7.75% for the Victorian Gas Distributors.

- AlintaGas Trading

  The real pre-tax Weighted Average Cost of Capital being proposed of 8.75% would appear to be high when compared, for example, to the 8.3% Weighted Average Cost of Capital recommended in OffGAR's Parmelia Pipeline Access Arrangement Draft Decision.

In assessing the proposed Rate of Return for the Tubridgi Pipeline System, the Regulator contemplated the Tubridgi Pipeline System having a similar commercial risk as the Parmelia Pipeline, and hence a similar rate of return, but a higher level of risk than larger transmission pipelines and distribution systems with more secure markets.

In assigning a value to the Rate of Return for the Tubridgi Pipeline System, the Regulator took a slightly different approach than in the Draft Decision for the Parmelia Pipeline to accounting for commercial risk in values assigned to the debt risk margin and the equity beta. This different approach resulted in different values for these parameters being used for the Tubridgi Pipeline System but, in the absence of changes to other parameters, would not have resulted in changes to the WACC. However, changes have occurred in the expected rate of inflation, the nominal risk free rate and the corporate tax rate since the Draft Decision on the

Parmelia Pipeline. This has resulted in the Regulator determining an appropriate Rate of Return for the Tubridgi Pipeline System being 8.2 percent (pre-tax real), compared to the 8.3 percent (pre-tax real) deemed appropriate for the Parmelia Pipeline in October 1999.

5.6.4 Additional Considerations of the Regulator

Calculation Methodology and CAPM Framework for WACC Determination

The Capital Asset Pricing Model (CAPM) is widely used by regulators internationally, particularly in the UK where it is used as the principal model for estimating the regulatory WACC, and is used extensively in both corporate finance and regulatory applications in Australia. The use by the Tubridgi Parties of CAPM theory to derive a WACC is therefore considered consistent with guidelines provided in section 8.31 of the Code.

The typical approach by regulators to date has been to use the CAPM to derive the "target" post-tax return or WACC, and then to make adjustments to the WACC for the net cost of taxation. At its simplest level, the CAPM specifies the WACC for an asset as a rate of return that can be earned by a risk-free asset plus a risk premium for the asset in question. The risk premium depends upon the risk of the particular asset relative to the risk associated with a diversified asset portfolio. Analytically:

$$WACC = R_f + b_a(R_m - R_f)$$

where R_f is the risk free rate, $(R_m - R_f)$ is the expected risk premium above the risk free rate for the portfolio of all assets, and b_a is the measure of the particular asset's relative risk, or its asset beta.[36]

In practice, asset betas cannot be observed or measured directly. Estimating a beta requires historical information on the economic returns to an asset (comprising the value of the returns plus the change in the market value of the asset), and on economic returns to the well-diversified portfolio of assets. As this type of information is only available on assets that are traded on the stock exchange, the CAPM is used to estimate the required return to the equity share of an asset, and stock market indices are used as a proxy for the market portfolio. Accordingly, the more common formulation of the CAPM is the following:

$$R_e = R_f + b_e(R_m - R_f)$$

where R_e is the required return on that equity, R_f is still the risk free rate and b_e is the measure of the particular equity's relative risk, or its equity beta. $(R_m - R_f)$ is now the expected risk premium above the risk free rate for a well-diversified portfolio of equities. The outcome of this model, therefore, is an estimate of the required after-tax return to equity. The return required by the other source of financing – debt – can be observed directly from the market, and the average of these sources of financing (weighted by the respective shares of debt and equity in the financing of the asset) provides an estimate of the WACC for the asset. That is:

[36] Note that, under this version of the CAPM, there is no need for assumptions about the cost of debt or capital structure for the entity to estimate its WACC.

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

where $\frac{E}{V}$ and $\frac{D}{V}$ are equity and debt as shares of total assets, V, and R_d is the cost of debt.

There are, however, a number of different expressions for the WACC that can be presented as the Regulator's "target" return. The different expressions for the WACC are derived by transferring one or more particular costs or benefits from the cash-flows to the WACC. The different forms of WACC that are commonly used as regulatory targets are as follows.

Post-Tax (Vanilla) WACC. This form of WACC is an estimate of the total return that the asset owners demand, and requires all potential costs and benefits (including tax and franking benefits) to be reflected in the cash-flows. It is the simplest form of WACC, and is synonymous with the WACC expression above.

Post-tax (Officer) WACC. This form of WACC is an estimate of the post-tax (cash) return on assets that the company needs to generate. The expression for the post-tax Officer WACC is:

$$WACC = R_e \cdot \frac{E}{V} \cdot \frac{1 - t_c}{(1 - t_c(1 - g))} + R_d \cdot \frac{D}{V} \cdot (1 - t_c)$$

where t_c is the corporate tax rate.

The post-tax Officer WACC overstates taxation liability because it assumes that all of the return on assets is taxed (whereas the portion that is distributed to debt providers is not taxed), and it provides shareholders with additional benefits through the dividend imputation system. Consequently, the Officer WACC is lower than the Vanilla WACC.

Post-tax (Monkhouse) WACC. This form of WACC is an estimate of the post-tax return on assets that the company needs to generate, where the value of franking credits is counted as part of that return. The expression for the post-tax Officer WACC is:

$$WACC = R_e \cdot \frac{E}{V} + (1 - t_c(1 - g)) \cdot R_d \cdot \frac{D}{V}$$

The Monkhouse WACC is higher than the Officer WACC as it includes the value of franking credits in measuring the required return.

Post-tax (Textbook) WACC. This form of WACC is similar to the Monkhouse WACC, except that the value of franking credits in cash flows is corrected for interest payments on debt. The expression for the post-tax Textbook WACC is:

$$WACC = R_e \cdot \frac{E}{V} + (1 - t_c) \cdot R_d \cdot \frac{D}{V}$$

Of the different WACC definitions, the Officer WACC is the most widely cited as the target WACC because this definition of WACC is commonly used for asset valuation and project evaluation. Many finance practitioners advocate the use of the Vanilla WACC as the regulatory target as it is the easiest to understand, and because it focuses on the total return that investors require, regardless of the source of the benefit. The Vanilla WACC is also often used in asset valuation exercises. The ACCC, on the other hand, focuses on the post-tax return on equity given that this measure of return appears to be the most widely understood by equity investors and is the measure of return that regulators in the USA generally consider.

The post-tax values of different forms of WACC values for the Tubridgi Pipeline System are indicated below, calculated from the parameters assumed by the Tubridgi Parties.

Alternative Rate of Return values calculated from the Tubridgi Parties' assumed CAPM parameters

Intermediate Targets	Nominal	Real
Post-tax (Vanilla) WACC	10.21%	7.52%
Post-tax (Officer) WACC	7.76%	5.13%
Post-tax (Monkhouse) WACC	9.07%	6.41%
Post tax (Textbook) WACC	8.57%	5.93%
Post-tax return on equity	14.17%	11.39%

The Tubridgi Parties used the Officer WACC in proposing a rate of return. The Regulator also assessed the rate of return on this basis. The various elements of the CAPM model and the positions taken by the Tubridgi Parties and the Regulator on each element are discussed below.

Market (Equity) Risk Premium, (R_m – R_f)

The market, or equity risk, premium measures the risk associated with holding the market portfolio of investments. It is the difference between the expected return on holding the market portfolio, and the risk free rate. The risk free rate is difficult to estimate, even on an historic basis, and is highly sensitive to the set of assumptions upon which it is derived. However, practitioners have generally used the actual average excess returns from holding shares compared to long dated (10 year) Government bonds over the long term as a proxy for the expected market risk premium.

Historical evidence indicates a market risk premium of around 6 to 8 percent.[37] However, given the recent growth rate of the equity market, it appears that investors' perceptions of risks are changing and "forward-looking" estimates of the equity premium are falling. In the UK, for example, utility regulators are currently using a range of between about 3 and 4 percent for the equity premium, as are UK equity analysts. Within Australia, many equity analysts now use an equity premium that is at the lower end of, or below, the range based upon estimates of the long-term historical average equity premium.

The use of historical returns also appears somewhat at odds with the CAPM, which is essentially "forward-looking" with respect to the equity premium. However, the use of a long-term historical average equity premium (a "backward-looking" equity premium)

[37] IPART, The Rate of Return for Electricity Distribution Businesses: Discussion Paper, November 1998, p16.

remains attractive, given the inherent volatility in equity markets. For example, in the case of a sudden correction in the stock market, forward-looking estimates of the equity premium would be expected to rise significantly, and equity analysts (and investors) would most likely revise upwards their perceptions of risk in the equity market.

In light of the emerging consensus that the forward-looking equity premium is lower than that implied by long-term historical averages, Australian regulators have been using an assumed equity premium that is at the lower end of, or below, the range implied by the long-term historical averages. The accepted values of market (equity) risk premiums have been in the range 5 to 6 percent, as indicated below.

Equity premiums adopted in recent regulatory decisions

Regulatory decision	**Market (equity) risk premium**
ORG Final Decision on Victorian Gas Distribution (October 1998)	6%
ACCC Final Decision on Victorian Gas Transmission (October 1998)	6%
IPART Great Southern Network Final Decision (March 1999)	5% – 6%
ACCC TransGrid Draft Decision (May 1999)	6%
ACCC Telstra's Originating and Terminating Access Undertaking (June 1999)	6%
IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999)	5% – 6%
IPART Albury Gas Company Draft Decision (August 1999)	5% – 6%
ACCC AGL Central West Pipeline Draft Decision (September 1999)	5.5%

Having regard to the range in market risk premiums adopted by Australian regulators to date, the Regulator considers that a market risk premium of 6 percent should be used to estimate the WACC for the Tubridgi Pipeline System. This is the same value of the market risk premium as used by the Tubridgi Parties.

Rate of Return on Debt, R_d

The required rate of return on debt , R_d, is determined by the following expression:

$$R_d = R_f + \text{debt risk margin}$$

where R_f is the nominal risk free rate.

<u>Risk Free Rate, R_f</u>

The Tubridgi Parties have assumed a nominal risk free rate of 6.37 percent and adopted an inflation rate forecast of 2.5 percent, implying a real risk free rate of 3.78 percent. The assumed nominal risk free rate was based upon the yield to maturity on 10 year

Commonwealth Government bonds. The source of its inflation forecast was not stated in the Access Arrangement documents.

In recent years, Australian regulators have all adopted a very similar approach to deriving the proxy real risk-free rate, based on one or other of the following methods.

- Deriving the nominal risk free rate from a recent average (20, 30 or 40 days) of the yields on Commonwealth bond rates, the real risk free rate from a recent average of the yields on Commonwealth index-linked bonds over the same period, and calculating the inflation forecast as the difference between these yields.

- Using the yield on bonds with either 5 year or a 10 year yield to maturity.

Whilst the different approaches seldom have a material effect on the proxy real risk free rate, the Regulator has decided to use the yield to maturity on 10 year Commonwealth Government Treasury Bonds as a proxy for the nominal risk free rate and the yield to maturity on the 10 year Commonwealth Government Capital Indexed Treasury Bonds as the proxy for the real risk free rate. The observed yield for the relevant bonds was taken as the average of the 20 trading days to 15 June 2000.

The difference between the two rates (calculated using the Fisher equation[38]) provides an inflation forecast over the relevant period. The use of Commonwealth capital indexed bonds has the advantage that it permits a market-based expectation of inflation to be taken into account. It has also been used by other regulators to provide a measure of inflation.[39]

As at 15 June 2000, this gave a nominal risk free rate of 6.27 percent, a real risk free rate of 3.40 percent, and a forecast rate of inflation of 2.78 percent. These values have been used by the Regulator to revise the WACC for the Tubridgi Pipeline System.

<u>Debt Risk Margin</u>

The Tubridgi Parties has assumed a debt risk margin of 1.2.

In assessing the debt risk margin, the Regulator considered the debt margins adopted by regulators in recent regulatory decisions, indicated as follows.

[38] Brealey, R.A. and Myers, S.C., 1996. *Principles of Corporate Finance*, fifth edition, New York McGraw–Hill, pp 642,643.

[39] Independent Pricing and Regulatory Commission, ACTEW's Electricity, Water and Sewerage Charges for 1999/2000 to 2003/2004, Draft Price Decision, February 1999; and IPART, Aspects of the NSW Rail Access Regime, Draft Report, February 1999.

Recent regulatory decisions on debt margins

Regulatory decision	Range for debt margin	Point estimate
ORG Final Decision on Victorian Gas Distribution (October 1998)	1.0% – 1.2%	1.2%
ACCC Final Decision on Victorian Gas Transmission (October 1998)	1.0% – 1.2%	1.2%
IPART Great Southern Network Final Decision (March 1999)	–	1.2%
IPART Albury Gas Company Draft Decision (August 1999)	1.0% – 1.2%	1.2%
IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999)	–	1.0%
ACCC TransGrid Draft Decision (May 1999)	–	1.0%
ACCC AGL Central West Pipeline Draft Decision (September 1999)	–	1.0%
Independent Gas Pipelines Access Regulator (WA) Parmelia Pipeline Draft Decision (October 1999)	–	2.0*
Independent Gas Pipelines Access Regulator (WA) Mid-West and South-West Distribution Systems Final Decision (June 2000)	–	1.3

* The value of 2 percent for the Parmelia Pipeline was derived using a different methodology for assigning values to the debt margin and equity beta for the purposes of addressing the risk associated with the pipeline business, and hence this value is not directly comparable with the debt margins for other pipelines as indicated in this table.

In view of the debt margins assumed for transmission pipelines in Australia, the Regulator considers that it is reasonable to assume a debt margin of 1.2 percent for the Tubridgi Pipeline System.

Return on Debt, R_d

Using the above estimates of the risk free rate and the debt risk margin, the nominal return on debt, R_d, was determined by the Regulator to be 7.47 percent, compared with 7.57 percent proposed by the Tubridgi Parties.

Rate of Return on Equity, R_e

As indicated above, the rate of return on equity is determined using the following expression.

$$R_e = R_f + b_e(R_m - R_f)$$

Equity Beta, b_e

The application of the CAPM requires an equity beta, b_e, to be determined for the Tubridgi Parties' regulated business. Since the Tubridgi Parties do not comprise a listed company, it is necessary to use a proxy beta, normally derived from estimates of betas for listed firms that are considered to have a comparable degree of systemic risk. Systematic risk relates to that portion of the variance in the return on an asset that arises from market-wide economic factors that affect returns on all assets, and which cannot be avoided by diversifying a portfolio of assets. The beta values indicate the sensitivity of the value of the particular asset to systematic risk.[40]

In deriving a proxy beta, it must be borne in mind that the level of risk faced by equity holders is affected by the level of gearing that is adopted by the firm. An increase in the level of gearing, *ceterus paribus*, increases the financial risk that is borne by equity holders, and so increases the equity beta. A common practice to permit comparison of estimated betas across firms with different capital structures is to convert the estimated equity betas into an asset beta (which is the estimate of the equity beta on the assumption that the firm was wholly equity financed). As asset betas measure only the underlying market risk of the asset, they can be compared across firms regardless of capital structure. Accordingly, practice amongst regulators has been to determine a proxy asset beta, and then to re-lever this into an equity beta that is consistent with the assumed capital structure of the entity, using the following expression:

$$b_e = b_a + (b_a - b_d).\frac{D}{E}$$

where b_a is the asset beta, b_d is the debt beta (indicating the sensitivity of the of the Tubridgi Parties' debt (risk premium) to the overall debt market).

The appropriateness of a proxy asset beta is dependent upon the businesses for which beta estimates are available having a similar level of systemic risk. Since there are few comparable infrastructure entities listed on the Australian Stock Exchange, regulatory practice in Australia has been to place weight upon publicly available beta estimates for firms that are operating in other countries. However, differences in the composition of equity markets between countries and differences in the regulatory regimes within which regulated businesses operate can affect the level of systemic risk that is borne by the proxy businesses. Therefore an element of judgement must be exercised as to the appropriateness of the proxy betas. The table below provides examples of recent asset betas calculated for international energy businesses.

[40] Peirson, G., Bird, R., Brown, R. and Howard, P., 1990. *Business Finance* 5th ed., New York, Sydney: McGraw-Hill, pp 96,97. Systematic risk is also referred to as non-diversifiable risk as no amount of diversification in an asset portfolio can eliminate it. The second component of the total risk of an asset is unsystematic or diversifiable risk which relates to variance in the value of the asset that arises from factors specific to that asset. In principle, this risk can be eliminated from an asset portfolio by adequate diversification of that portfolio.

Selected international asset betas

Source	**Industry Group/Firm**	**Asset Beta Range**
CS First Boston (1997)	8 US gas distribution companies	0.26 – 0.48 (0.36)
	6 US gas transmission companies	0.35 – 0.61 (0.50)
	3 UK electricity distributors	0.97 – 1.39 (1.14)
	Allgas	0.11
	AGL	0.56
	Average for gas distribution	**0.50**
	Average for gas transmission	**0.45**
Macquarie Risk Advisory Service (1998)	22 international electricity distribution companies	0.25 – 0.85 (0.45)
	17 international gas distribution companies	0.25 – 0.75 (0.40)
	Allgas	0.30
	AGL	0.40
	Average for distribution businesses	**0.35 – 0.50**
IPART (1998)	Telecommunications	0.41
	Infrastructure and Utilities	0.46
	Allgas	0.53
	AGL	0.46

There is some evidence that the asset betas for businesses operating under incentive-compatible regulation are likely to be higher than asset betas for businesses operating under more conventional rate-of-return regulation.[41] The ranges for asset betas that have been accepted by regulators in Australia in recent decisions, and the asset betas adopted recently by UK regulators for comparable industries, are indicated below together with the form of regulation applied.

[41] For example, Alexander, Mayer and Weeds (1996) *Regulatory Structure and Risk and Infrastructure Firms: An International Comparision*, World Bank Policy Research Working Paper No. 1698, which argues that asset betas for businesses operating under incentive-compatible regimes could be as much as 0.3 to 0.4 higher than equivalent companies operating under conventional rate-of-return regimes.

Asset betas adopted by Australian and UK regulators

Gas Regulatory Decisions	**Asset Beta Range**	**Form of Regulation**
ORG Final Decision on Victorian Gas Distribution (October 1998)	0.45 – 0.60 (adopted 0.55)	Price cap
ACCC Final Decision on Victorian Gas Transmission (October 1998)	0.45 – 0.60 (adopted 0.55)	Price cap
IPART Great Southern Network Final Decision (March 1999)	0.40 – 0.50	Price cap
IPART Albury Gas Company Draft Decision (August 1999)	0.40 – 0.50	Price cap
ACCC AGL Central West Pipeline Draft Decision (September 1999)	0.60	Price cap
Western Australian Independent Gas Pipelines Access Regulator Draft Decision on the Parmelia Pipeline (October 1999)	0.6	Price cap
Western Australian Independent Gas Pipelines Access Regulator Final Decision on the Mid-West and South-West Gas Distribution Systems (June 2000)	0.55	Price cap
Electricity Regulatory Decisions	**Asset Beta Range**	**Form of Regulation**
ACCC TransGrid Draft Decision (May 1999)	40 – 0.50 (adopted 0.45)	Revenue cap
IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999)	0.35 – 0.50	Unsettled
UK Regulatory Decisions	**Asset Beta Range**	**Form of Regulation**
Ofgas/MMC Review of Transco (the UK transmission company) (May 1997))	0.45 – 0.6 [42]	Price cap
Offer Draft Decision on UK Electricity Distributors August 1999)	0.70 [43]	Price cap

Having regard to the evidence provided from observed equity betas and the ranges for the asset betas that have been adopted by Australian regulators to date, the Regulator considers that a range for the asset beta of between 0.45 and 0.60 would generally constitute a reasonable range for the asset beta of an Australian gas transmission business. However, the

[42] Monopolies and Mergers Commission, *BG plc: A Report under the Gas Act 1986 on the Restriction of Prices for gas Transportation and Storage Services* (1997).

[43] Office of Electricity Regulation (UK), *Reviews of Public Electricity Suppliers 1998 to 2000: Distribution Price Control Review Draft Proposals*, August 1999. Offer used an equity beta of 1.0 with a gearing level of 50%. The high assumed asset beta comes from it using a debt margin of 1.4% with a mid-point equity premium of 3.5%, which implies a debt beta of 0.40 (using the method for estimating the debt beta discussed earlier). A more reasonable debt beta – say, 0.20 – would give a much lower estimated asset beta (in that case, of 0.6).

Regulator considers that the Tubridgi Parties are likely to bear a higher level of risk than other gas transmission businesses for principal reason that the Tubridgi Pipeline System is a small "feeder" pipeline located close to the production end of the gas supply system. As a consequence, there are a limited number of potential Users of the pipeline system, relative to a "downstream" transmission pipeline or distribution system, and the market for services is highly dependent upon production from a limited number of gas fields.

In light of the relatively high risk status of the Tubridgi Pipeline System an asset beta at upper end of this acceptable range (0.65) has been used to estimate the WACC. This asset beta is higher than the value of 0.6 used by the Tubridgi Parties.

The debt beta, b_d, is not directly observable. The Tubridgi Parties estimated the debt beta using the following "Macquarie" expression:

$$b_d = \frac{R_d - R_f - \text{bank costs}}{R_m - R_f}$$

where $R_d - R_f$ is the company debt premium, $R_m - R_f$ is the market risk premium and "bank costs" represents a lender margin that was assumed in this case to equal 50 basis points. Using this expression, the Tubridgi Parties derived a debt beta value of 0.12.

The Regulator does not support the Macquarie method of excluding a lender margin in determining the debt beta, considering that this results in a lowering of the debt beta, with consequent increases in the equity beta and asset beta that would misleadingly imply a higher level of risk. The Regulator calculated the debt beta as the ratio of the debt premium to the market risk premium, giving a value of 0.20.

Calculation of the asset beta from equity and debt betas also requires assumption of a gearing ratio for the Tubridgi Parties. The Tubridgi Parties assumed a financing structure comprising 60 percent debt and 40 percent equity. This gearing level is consistent with reviews of gearing levels in recent decisions on regulated infrastructure in the eastern States.[44] Adoption of this gearing level is consistent with the requirements of section 8.31 of the Code that requires that the weighted average return on funds should be calculated by reference to a financing structure that reflects standard industry structures. As the standard target gearing for gas companies is considered to be 60 percent by the ACCC, ORG and IPART, the Regulator considers such a level of gearing to be appropriate for the determination of the WACC for the Tubridgi Pipeline System.

Assuming a gearing (debt to equity) ratio of 60:40, an asset beta of 0.65 and a debt beta of 0.20 correspond to an equity beta of 1.33. This is close to the equity beta used by the Tubridgi Parties (1.3).

[44] ACCC, 1998. Final Decision on the Access Arrangements by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System, Transmission Pipelines Australia Pty Ltd and Transmission Pipelines (Assets) Pty Ltd for the Western Transmission System, and by Victorian Energy Networks Corporation for the Principal Transmission System; IPART, 1999, Draft Decision Albury Gas Company Ltd.

Return on Equity, R_e

Using the above estimates of the equity beta, risk free rate and market risk premium, the nominal post tax return on equity, R_e, was determined by the Regulator to be 14.22 percent, compared with 14.17 percent proposed by the Tubridgi Parties.

Taxation

There are three main taxation issues relevant to the determination of the WACC. These are the effective rate of company taxation, imputation of franking credits, and conversion of the post-tax WACC to a pre-tax WACC.

Rate of Taxation

The target revenue that is used by the Regulator to set regulatory controls is a pre-tax revenue stream.[45] This target revenue includes the "cost" of a rate of return on assets that includes taxation liabilities. The Regulator must therefore make an assumption about the likely cost of taxation to that entity. It follows that the accuracy of the assumption that is made about the cost of tax will affect whether the target revenue is expected to provide the target post-tax return. If the cost of taxation is overestimated, then the target revenue would be expected to provide the regulated entity with a return that is higher than market requirements. Conversely, if the cost of taxation is underestimated, then the target revenue would be expected to provide the regulated entity with a return that is below market requirements.

A critical question facing regulators in Australia in assessing the most appropriate treatment of taxation has been whether the assumed cost of taxation should reflect the effective taxation rate or the statutory taxation rate. The effective taxation rate (actual taxation liability as a proportion of regulatory profit) may differ from the statutory taxation rate for several reasons including the divergence between economic depreciation and taxation depreciation, and the ability of the regulated entity to deduct the nominal cost of debt for taxation purposes. In general, the effective rate of taxation is likely to be below the statutory rate.

There has been some recent conjecture, most notably by the ACCC, that an effective tax rate, which adjusts the statutory tax rate to reflect the excess of tax depreciation of assets over economic depreciation should be used in the CAPM framework. However, this approach attracted widespread criticism on the basis that it would be difficult to integrate the effective tax rate into a single-period CAPM, particularly where the lives of the assets ranged from 30 to 50 years. The ACCC acknowledged these difficulties and reverted to using the statutory tax rate.

Given the problems encountered by regulators in estimating an effective rate of taxation from a long-term estimate of the average cost of tax, there has been recent conjecture that an effective rate of tax is best estimated using a short-term estimate of the cost of tax, through either a *flow-through* or *normalisation* approach.[46] The ACCC, in its statement of regulatory

[45] That is, regardless of what a regulator might decide or intend, the revenue that the entity earns from its regulated business will be assessable for company taxation according to the relevant statutes.

[46] Under the flow-through approach, an explicit estimate is made of the cost of tax for the regulated entity for each year of the Access Arrangement Period and added to the pre-tax revenue requirement. Under the normalisation approach, a notional cost of taxation is included within the revenue requirement, where this cost of taxation is calculated on the assumption that the taxation system only permits regulatory depreciation rather

principles for the regulation of electricity transmission revenues, has proposed setting required revenues based on a forecast of taxation liabilities (net of the assessed value of franking credits) over the relevant regulatory period, which is consistent with either a flow-through or normalisation approach.[47] In addition, whilst the ACCC estimated the taxation liability for the AGL Central West Pipeline in its draft decision essentially on the basis of a long-term average cost of tax, it is understood that the ACCC is considering implementing normalisation for that pipeline in its final decision.

In order to compensate for the cost of tax, the Tubridgi Parties have grossed-up the proposed post-tax nominal WACC by the statutory tax rate at the time the Access Arrangement was submitted (36 percent) in order to derive a pre-tax nominal WACC, and have then deducted inflation in order to derive the pre-tax real WACC.

The Regulator has given consideration to adopting an effective rate of tax, based on a short-term estimate of the cost of tax using either a pass-through or normalisation approach, in its assessment of the likely cost of tax to the Tubridgi Parties. However, despite the theoretical advantages associated with using these techniques, the Regulator is mindful of the complexities involved in their practical application, which will require additional and specific research before implementation. In the absence of any definitive studies demonstrating the accuracy of using an effective rate of tax in the CAPM, based on a pass-through or normalisation approach, the Regulator considers that the statutory corporate tax rate is appropriate for the purposes of this Draft Decision.

The Regulator is mindful of the changes to corporate taxation rates that will occur over the Access Arrangement Period for the Tubridgi Pipeline System: a reduction from 36 percent to 34 percent for 2000/01, and to 30 percent thereafter. For the purposes of determining Reference Tariffs, the Regulator has determined a rate of return based on the average taxation rate over the Access Arrangement Period, being 31.6 percent.

Valuation of Franking Credits

Franking credits are an allowance under the Australian taxation system that permit dividends paid to shareholders to be exempt from personal income tax in recognition of company tax having already been paid on profits from which the dividends are paid. The value of franking credits is incorporated into the WACC calculation to reflect the benefits that shareholders gain from franking, and the consequent lower requirement of shareholders for the rate of return on investment.

The approach for reflecting the value of imputation credits that has emerged as standard practice is to use a market (equity) risk premium that assumes that Australia has a classical tax system, then to adjust the WACC or cash-flows directly to reflect the non-cash benefits associated with franking credits. The mechanism used to achieve this – the gamma term –

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than taxation depreciation to be deducted for taxation purposes. Both the ORG and the ACCC have discussed in detail the problems that are associated with using simple transformations or empirical estimates of the long-term average cost of taxation to set regulated revenues, and have stated that approaches like flow-through or normalisation offer advantages. These matters were discussed in ACCC, *Final Decision: Access Arrangement by Transmission Pipelines Australia Pty Ltd*, October 1998, ORG, *Final Decision: Access Arrangements for Westar, Multinet and Stratus*, October 1998, and more recently in ORG, *2001 Electricity Distribution Price Review: Cost of Capital Financing (Consultation Paper No 4)*, May 1999.

[47] ACCC, *Draft Statement of Regulatory Principles of Transmission Revenues*, May 1999.

can then be interpreted as the value of each franking credit that is created by the firm, as a proportion of its face value.

It is common for downward adjustments to be made to the value of franking credits once distributed to arrive at a gamma value, to account for the fact that not all franking credits are paid out in the year in which they are created. Hathaway and Officer suggest that only 80 percent of franking credits are distributed in the year in which they are created.[48] The ORG and the ACCC have used a gamma value that was 70 to 80 percent of franking credits created, which is consistent (albeit erring on the conservative side) with the findings of Hathaway and Officer. The gamma values that have been accepted by regulators in recent regulatory matters are provided in the table below.

Gamma Assumptions Adopted by Australian Regulators

Regulatory Decision	Gamma Assumption
ORG Final Decision on Victorian Gas Distribution (October 1998)	0.50
ACCC Final Decision on Victorian Gas Transmission (October 1998)	0.50
IPART Great Southern Network Final Decision (March 1999)	0.30 – 0.50
IPART Albury Gas Company Draft Decision (August 1999)	0.30 – 0.50
IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999)	0.30 – 0.50
ACCC TransGrid Draft Decision (May 1999)	0.50
ACCC Telstra's Originating and Terminating Access Undertaking (June 1999)	0.50
ACCC AGL Central West Pipeline Draft Decision (September 1999)	0.50
Independent Gas Pipelines Access Regulator (WA) Parmelia Pipeline Draft Decision (October 1999)	0.50
Independent Gas Pipelines Access Regulator (WA) Mid-West and South-West Distribution Systems Draft Decision (March 2000)	0.50

The Tubridgi Parties have assumed a gamma value of 0.3 for the determination of the WACC.

The Regulator has decided to use a gamma value of 0.5 in the determination of the WACC, which is consistent with all of the decisions of the ACCC and ORG.

[48] Hathaway and Officer (1992), *The Value of Imputation Credits*, unpublished manuscript, Finance Research Group, Graduate School of Management, University of Melbourne.

Conversion of Post-Tax WACC to Pre-Tax WACC

The conversion of the post-tax WACC to the pre-tax WACC is undertaken by adjusting for the corporate tax rate, including the effects of imputation of franking credits.

In most decisions to date, the Australian regulators have based their assumptions about the cost of tax on two simple transformations of a post-tax WACC to a pre-tax WACC:

i. forward (or market) transformation, involving division of the post-tax nominal WACC by one minus the statutory taxation rate, and then deducting inflation (using the Fisher transformation[49]) to derive the pre-tax real WACC; and

ii. reverse transformation, involving first deducting inflation from the post-tax nominal WACC, and then grossing up the post tax real WACC by one minus the statutory taxation rate.

The recent decisions of Australian regulators in gas and electricity matters have used these methodologies in the following ways to correct for the cost of taxation.

Approaches of Australian regulators to the derivation of pre-tax WACC

Regulatory decision	**Approach**	**Forward transformation pre-tax WACC**	**Adopted pre-tax WACC**
ORG Final Decision on Victorian Gas Distribution (October 1998)	Used the forward and reverse transformations to generate a range for the WACC, and chose a value towards the upper end of this range.	8.0%	7.75%
ACCC Final Decision on Victorian Gas Transmission (October 1998)	Used the forward and reverse transformations to generate a range for the WACC, and chose a value towards the upper end of this range.	8.0%	7.75%
IPART Great Southern Network Final Decision (March 1999)	Used the forward and reverse transformations, together with ranges for the other inputs, to generate a range for the WACC, and chose a value within this range.	6.8% – 8.4%	7.75%
IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999)	Used the forward and reverse transformations, together with ranges for the other inputs, to generate a range for the WACC, and chose a value within this range.	6.6% – 8.6%	7.5% (Urban) 7.75% (Rural)
IPART Albury Gas Company Final Decision (December 1999)	Used the forward and reverse transformations, together with ranges for the other inputs, to generate a range for the WACC, and chose a value within this range.	5.1% – 8.6%	7.75%

[49] $Real\ WACC = \frac{1 + nominal\ WACC}{1 + i} - 1$, where i is the inflation rate.

Approaches of Australian regulators to the derivation of pre-tax WACC

Regulatory decision	Approach	Forward transformation pre-tax WACC	Adopted pre-tax WACC
ACCC AGL Central West Pipeline Draft Decision (September 1999)	Calculated a pre-tax WACC based on a long term effective tax rate. The pre-tax WACC was calculated empirically (i.e. based on forecast cash flows over the long term). It is understood that the ACCC is contemplating including a normalisation mechanism for the Central West Pipeline in its final decision.	8.4%	7.5%
Independent Gas Pipelines Access Regulator (WA) Parmelia Pipeline Draft Decision (October 1999)	Used the forward transformation and single values of other inputs to generate a point estimate for the WACC.	8.3%	8.3%
Independent Gas Pipelines Access Regulator (WA) Mid West and South-West Distribution Systems Final Decision (June 2000)	Used the forward transformation together with single values of other inputs to generate a range for the WACC.	7.5%	7.5%

The Regulator has adopted the forward transformation methodology in this Draft Decision. The Regulator's use of the forward transformation reflects a view that the announced changes to the company taxation regime in Australia are likely to narrow the gap between the statutory and effective tax rates for infrastructure firms in Australia. It is noted, however, that there is no consistent approach to the issue amongst the other Australian regulators, and that an after-tax WACC has been adopted in a number of recent decisions in Australia, with an allowance for taxation included explicitly in the revenue benchmark.

WACC Determination

A comparison of values of input variables to the WACC calculation used by the Tubridgi Parties with values considered reasonable by the Regulator is provided as follows.

Estimation of the rate of return

Parameter	**Parameter symbol**	**Value used by the Tubridgi Parties**	**Value proposed by the Regulator**
Risk free rate (nominal)	R_f	6.37%	6.27%
Risk free rate (real)	R_f	3.07%	3.40%
Market risk premium	–	6. 0%	6.0%
Asset beta	b_a	0.6	0.65
Equity beta	b_e	1.3	1.33
Debt beta	b_d	0.235	0.20
Cost of debt margin		1.2%	1.20%
Corporate tax rate	T	36%	31.6%
Franking credit value	g	30%	50%
Debt to total assets ratio	D/V	60%	60%
Equity to total assets ratio	E/V	40%	40%
Expected inflation	p_e	2.5%	2.78%

The revised WACC estimates for the Tubridgi Parties are as follows.

Revised WACC for the Tubridgi Pipeline System

Estimated WACC	**Nominal**	**Real**
Post-Tax (Officer)	7.7%	4.8%
Pre-tax (forward transformation of Officer WACC)	11.2%	8.2%
Pre-tax (reverse transformation of Officer WACC)	10.0%	7.0%

As stated above, the Regulator has used the forward transformation to derive the implied allowance for corporate taxation. Accordingly, on the basis of financial advice, the Regulator has adopted a real pre-tax WACC of 8.2 percent for the purposes of assessing the Tubridgi Parties' proposed Reference Tariff. The implied nominal pre tax WACC is 11.2 percent.

The returns to equity that are implied by this WACC estimate are as follows.

Returns on equity implicit in the revised pre-tax WACC	
Nominal post-tax return on equity	14.2 percent
Real post-tax return on equity	11.1 percent
Nominal pre tax return on equity	16.9 percent
Real pre-tax return on equity	13.7 percent

The following amendment is required before the Access Arrangement will be approved.

> Amendment 36
>
> The Access Arrangement and Access Arrangement Information should be amended to reflect a pre-tax real rate of return of 8.2 percent.

5.7 DEPRECIATION SCHEDULE

5.7.1 Access Code Requirements

Sections 8.32 to 8.34 of the Code specify rules for depreciation of assets that form part of the Capital Base, for the purposes of determining a Reference Tariff.

Section 8.32 defines a Depreciation Schedule as the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the covered pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of determining a Reference Tariff (the Depreciation Schedule).

Section 8.33 requires that the Depreciation Schedule be designed:

(a) so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of the Reference Tariffs has assumed significant market growth and the pipeline has been sized accordingly);

(b) so that each asset or group of assets that form part of the covered pipeline is depreciated over the economic life of that asset or group of assets;

(c) so that, to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the covered pipeline is adjusted over the life of that asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and

(d) subject to provisions for capital redundancy in section 8.27 of the Code, so that an asset is depreciated only once (that is, so that the sum of the Depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the Capital Base).

Section 8.34 provides for the application of depreciation principles in the determination of Total Revenue using IRR or NPV methodologies. If the IRR or NPV methodology is used, then the notional depreciation over the Access Arrangement Period for each asset or group of assets that form part of the covered pipeline is:

(a) for an asset that was in existence at the commencement of the Access Arrangement Period, the difference between the value of that asset in the Capital Base at the commencement of the Access Arrangement Period and the value of that asset that is reflected in the Residual Value; and

(b) for a New Facility installed during the Access Arrangement Period, the difference between the actual cost or forecast cost of the Facility (whichever is relevant) and the value of that asset that is reflected in the Residual Value,

and, to comply with section 8.33:

(c) the Residual Value of the covered pipeline should reflect notional depreciation that meets the principles of section 8.33; and

(d) the Reference Tariff should change over the Access Arrangement Period in a manner that is consistent with the efficient growth of the market for the Services provided by the pipeline (and which may involve a substantial portion of the depreciation taking place towards the end of the Access Arrangement Period, particularly where the calculation of the Reference Tariffs has assumed significant market growth and the pipeline has been sized accordingly).

5.7.2 Access Arrangement Proposal

The methodology proposed by the Tubridgi Parties for depreciation of the Capital Base is described in section 4.1.3 of the Access Arrangement Information. This methodology involves an "accelerated" straight-line depreciation of the Capital Base using depreciation rates that are greater than would be implicit in straight-line depreciation of assets over their entire lives. A comparison of the depreciation rates that would result from straight-line depreciation over entire asset lives and the proposed depreciation rates is as follows.

Tubridgi Parties' proposed rates of depreciation

Asset Category	Asset life (Years)	Implicit annual depreciation rates in straight-line depreciation over technical asset life (percent)	Proposed annual depreciation rates for straight-line depreciation (percent)
Transmission pipelines	80	1.25	5
Meter stations	50	2	5
SCADA and communications	15	6.7	6.7

In calculating annual depreciation costs, the accelerated depreciation rates were multiplied by the optimised replacement cost values of the asset categories and increased annually by a factor of one plus an inflation rate of 2.5 percent. The resultant annual depreciation costs are as follows.

Tubridgi Parties proposed depreciation (nominal $million)

Asset Category	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Transmission pipelines	1.15	1.17	1.20	1.23	1.26
Meter stations	0.15	0.15	0.16	0.16	0.16
SCADA and communications	0.01	0.01	0.01	0.01	0.01
Total	**1.31**	**1.34**	**1.37**	**1.41**	**1.44**

5.7.3 Submissions from Interested Parties

- Western Power

  The Tubridgi Parties believe that the capacity of the Tubridgi Pipeline System will be utilised in decades to come and have proposed that the useful life be the same as the economic life of 80 years.

  In Appendix B of the Access Arrangement it is stated that straight-line depreciation over the economic useful life has been used. The Tubridgi Parties have not included a residual value, as they believe that there would be a net cost to abandon the pipeline system. The Tubridgi Parties have then accelerated the depreciation on the asset to 5 percent for initial Access Arrangement Period because there is a risk that the pipeline may lie idle for a period of time or even become redundant beyond this time.

  Western Power would like further investigation into the reason of having an economic life and useful life at 80 years when there has also been a need to depreciate the pipeline system using an accelerated method as forecast demand is low and declining. We understand that the Tubridgi Parties will review the demand and hence the depreciation factors by June 2002; but further clarification on the above is encouraged.

- Office of Energy

  The Office of Energy estimates that accelerating the depreciation rate from 1.25 percent to 5 percent has had the effect of increasing the proposed Reference Tariffs by between 26 percent and 29 percent over the Access Arrangement Period.

  Section 8.33 of the Code establishes principles for depreciating the Capital Base for the purposes of determining a Reference Tariff consistent with the Cost of Service method chosen by the Tubridgi Parties. Under section 8.33, the Depreciation Schedule should, amongst other things, be designed "so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of the Reference Tariffs has assumed significant market growth and the Pipeline has been sized accordingly)."

  The Office of Energy considers that the accelerated depreciation chosen by the Tubridgi Parties, is inconsistent with the principles of the Code and with section 8.33 (above) in particular, and as such the Regulator should consider requiring amendments to the proposed Access Arrangement to correct that inconsistency.

The Office of Energy also suggests that the Regulator may wish to consider deferring a substantial portion of the depreciation to the future periods of the Access Arrangement.

As noted by the Tubridgi Parties in the Access Arrangement Information, there is evidence to suggest that there will be a long-term requirement for a gas haulage service on the Tubridgi Pipeline System. Accordingly, the Tubridgi Parties have adopted an economic life for the Tubridgi Pipeline of 80 years.

Further, as noted above, the Tubridgi Parties have nominated an Initial Capital Base valuation based on optimising the separate Tubridgi and Griffin Pipelines into a single pipeline with the same capacity as the entire combined capacity of the two pipelines. The Office of Energy considers that the accelerated depreciation chosen by the Tubridgi Parties, based on the argument that it reflects the risk associated with the assets being made redundant when existing gas fields are depleted, is inconsistent with the rest of the assumptions in the proposed Access Arrangement. Those assumptions have already led to substantially higher proposed Reference Tariffs. For example, if there was a strong risk associated with the assets being made redundant when existing gas fields are depleted, then the Initial Capital Base would have been reduced to reflect that risk, which would have produced substantially lower Reference Tariffs.

It should be noted that straight-line depreciation over the economic useful life of the respective assets has been used by the Tubridgi Parties in depreciating the optimised replacement cost of the asset base.

- CMS Gas Transmission Australia

  The Tubridgi Access Arrangement states asset lives as being 80 years for pipeline with 50 years for meter stations and 15 years for SCADA and communications assets. Depreciation for pipeline and meter stations however is based on a 20 year life. The argument presented is to accelerate depreciation in order to reduce the risk of assets being made redundant if future demand fails to materialise (section 4.1.3 of the Access Arrangement Information). CMS supports the principle espoused by the Tubridgi Parties as being an appropriate and pragmatic response to the recognition of a commercial risk of this nature.

- BHP Petroleum Pty Ltd

  The use of accelerated depreciation based on 15 to 20 year asset life for the determination of total revenue requirement is, in our view, a realistic timeframe. However, this is not consistent with the assumptions used to determine the Initial Capital Base. The assumption of an 80 year life to arrive at an initial capital base of $22.7 million at the beginning of the Access Arrangement Period increases the return on capital required during the period. The use of accelerated depreciation within the Access Arrangement Period increases the depreciation component of the revenue requirement. In combination these assumption have the effect of unnecessarily increasing the revenue requirement.

  The depreciation methodology should be explained, particularly as depreciation schedule shows depreciation amounts continually increasing in nominal terms over the access period. The Regulator should require a consistent treatment of depreciation, and require that the Service Provider use an industry accepted depreciation methodology.

- AlintaGas Trading

  The Tubridgi Parties do not appear to use a consistent depreciation rate. In obtaining the DORC valuation of $23.755 million, the Tubridgi Parties seem to have depreciated the pipeline and meter stations at a rate of 1.25 percent from its optimised replacement cost of $26.092 million. Yet the Tubridgi Parties propose a 5 percent depreciation rate during the first Access Arrangement Period.

In assessing the Depreciation Schedule proposed by the Tubridgi Parties, the Regulator considered the following matters raised by public submissions.

- The justification for accelerated depreciation and the corresponding assumption of useful lives of the assets being less than the physical or technical lives.

- Consistency of the proposed Depreciation Schedule with assumptions as to depreciation made in respect of determining the Initial Capital Base.

- Whether the Depreciation Schedule should reflect the current operation of the Tubridgi Pipeline System at substantially less than capacity.

Section 8.33(b) of the Code sets out a principle for depreciation that each asset or group of assets that form part of a covered pipeline is depreciated over the economic life of the asset or group of assets. The Regulator considers that this principal is consistent with accelerated depreciation in circumstances where there are reasonable expectations that the useful life of assets (i.e. the period over which the assets may be used to generate a revenue stream) is less than the envisaged technical life of the assets. It may reasonably be expected that the useful life of the assets of the Tubridgi Pipeline System would be limited by production from the relevant gas fields, and hence accelerated depreciation is considered to be consistent with the principles of the Code.

The Regulator noted, however, that the proposed accelerated depreciation assets for the purposes of a forward-looking Depreciation Schedule is inconsistent with assumptions of past depreciation made in estimating DAC and DORC values for the purposes of valuing the Initial Capital Base. This was discussed in section 5.3.4 of this Draft Decision in relation to the Initial Capital Base. Given that the Tubridgi Parties have proposed accelerated depreciation of assets over the Access Arrangement Period and in the absence of other information on past depreciation practice, it is unreasonable to assume that a similar depreciation methodology would not have been used in the past. For this reason, the Regulator revised the estimates of DAC and DORC values of the pipeline assets to reflect the same depreciation rates as proposed for the Depreciation Schedule.

While regarding accelerated depreciation to be consistent with the depreciation principles set out in the Code, the Regulator is cognisant of the current use of the pipeline assets at substantially less than capacity and the arguable redundancy of assets. However, the Regulator considers that the redundancy of assets should be addressed though the value of the Capital Base and has proposed that the Access Arrangement should be amended to include a Redundant Capital Policy. In the absence of market growth for gas transport in the Tubridgi Pipeline System, this policy will have the effect of removing amounts from the Capital Base at the time of Review of the Access Arrangement (section 5.3.4 of this Draft Decision), thus reducing depreciation costs. While the delay in exercising any capital redundancy provisions may benefit the Tubridgi Parties, the Regulator considers this to be a reasonable balancing of interests between the Service Provider and Users.

5.7.4 Additional Considerations of the Regulator

The Regulator had no additional concerns with the proposed Depreciation Schedule. However, it is noted that by virtue of the Regulators revised value of the Initial Capital Base, that the depreciation schedule for pipeline assets will be altered and the Access Arrangement needs to be amended to reflect this, as follows.

Revised depreciation ($million at 30 June 1999)

Asset Category	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Transmission pipelines	0.729	0.729	0.729	0.729	0.729
Meter stations	0.113	0.113	0.113	0.113	0.113
SCADA and communications	0.014	0.014	0.014	0.014	0.014
Total	**0.855**	**0.855**	**0.855**	**0.855**	**0.855**
Total proposed by Tubridgi Parties.	**1.31**	**1.31**	**1.31**	**1.31**	**1.31**

The following amendment is required before the Access Arrangement will be approved.

Amendment 37

The Access Arrangement and Access Arrangement Information should be amended to reflect depreciation costs over the Access Arrangement Period as follows.

Depreciation ($million at 30 June 2000)

Asset Class	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Transmission pipe	0.729	0.729	0.729	0.729	0.729
Meter Stations	0.113	0.113	0.113	0.113	0.113
SCADA & comm.	0.014	0.014	0.014	0.014	0.014
Total	**0.855**	**0.855**	**0.855**	**0.855**	**0.855**

5.8 TOTAL REVENUE

5.8.1 Access Code Requirements

Sections 8.4 and 8.5 of the Code require that the revenue to be generated from the sales (or forecast sales) of all services over the Access Arrangement Period (the Total Revenue) be determined, or be able to be expressed in terms of, one of three methodologies.

- Cost of Service: the 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) a return (Rate of Return) on the value of the capital assets that form the covered pipeline (Capital Base);

  (b) depreciation of the Capital Base (depreciation); and

  (c) the operating, maintenance and other non-capital costs incurred in providing all Services provided by the Covered Pipeline (Non-Capital Costs).

- Internal Rate of Return (IRR): the Total Revenue will provide a forecast IRR for the Covered Pipeline that is consistent with the principles in sections 8.30 and 8.31 of the

Code. The IRR should be calculated on the basis of a forecast of all costs to be incurred in providing such Services (including capital costs) during the Access Arrangement Period. The initial value of the covered pipeline in the IRR calculation is to be given by the Capital Base at the commencement of the Access Arrangement Period and the assumed residual value of the Covered Pipeline at the end of the Access Arrangement Period (Residual Value) should be calculated consistently with the principles in section 8 of the Code.

- Net Present Value (NPV): the Total Revenue will provide a forecast NPV for the covered pipeline equal to zero. The NPV should be calculated on the basis of a forecast of all costs to be incurred in providing such services (including capital costs) during the Access Arrangement Period, and using a discount rate that would provide the Service Provider with a return consistent with the principles in sections 8.30 and 8.31 of the Code. The initial value of the Covered Pipeline in the NPV calculation is to be given by the Capital Base at the commencement of the Access Arrangement Period and the assumed Residual Value at the end of the Access Arrangement Period should be calculated consistently with the principles in section 8 of the Code.

The methodology used to calculate the Cost of Service, an IRR or NPV should be in accordance with generally accepted industry practice.

Section 8.6 of the Code recognises that a range of values may be attributed to the Total Revenue by the above methodologies. This gives recognition to the manner in which the Rate of Return, Capital Base, Depreciation Schedule and Non-Capital Costs may be determined, in each case involving discretion.

In order to determine an appropriate value within this range the Regulator may have regard to any financial and operational performance indicators considered by the Regulator to be relevant in order to determine the level of costs within the range of feasible outcomes under section 8.4 of the Code that is most consistent with the objectives contained in section 8.1 of the Code. Section 8.7 of the Code requires that, if the Regulator has considered financial and operational performance indicators for the purposes of section 8.6 of the Code, it must identify the indicators and provide an explanation of how they have been taken into account.

5.8.2 Access Arrangement Proposal

The Tubridgi Parties utilised a cost of service methodology for the determination of Total Revenue, with costs expressed in nominal terms reflecting an assumed annual inflation rate of 2.5 percent (section 4 of the Access Arrangement Information).

The breakdown of the Total Revenue into constituent costs is as follows.

Tubridgi Parties' proposed Total Revenue (nominal $million)

Cost Category	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Return on capital	2.021	1.955	1.884	1.808	1.727
Depreciation	1.305	1.337	1.371	1.405	1.440
Non-Capital Costs	0.495	0.507	0.520	0.533	0.546
Total	**3.821**	**3.799**	**3.775**	**3.746**	**3.713**

By correcting for the assumed 2.5 percent inflation, the Total Revenue and cost breakdown in real terms is as follows.

Tubridgi Parties' proposed Total Revenue ($million at 30 June 1999)

Cost Category	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Return on capital	2.021	1.907	1.793	1.679	1.565
Depreciation	1.305	1.305	1.305	1.305	1.305
Non-Capital Costs	0.495	0.495	0.495	0.495	0.495
Total	**3.821**	**3.707**	**3.593**	**3.479**	**3.365**

5.8.3 Submissions from Interested Parties

Derivation of Total Revenue

- BHP Petroleum Pty Ltd

  The use of the cost of service methodology is acceptable provided the various components are based on the application of consistent and reasonable principles in determining the cost. We have shown that there are inconsistencies between the methodology used to calculate the Initial Capital Base and hence the revenue required to provide a return on capital base, and the accelerated depreciation schedule over the Access Arrangement Period. This inconsistency tends to increase the revenue requirement and hence the tariff. The Regulator must be satisfied that this Total Revenue reasonably represents the cost of providing the service. On the basis of the issues raised above, we do not believe that the Regulator can draw this conclusion.

In assessing the proposed Initial Capital Base and Depreciation Schedule, the Regulator considered the different depreciation assumptions made by the Tubridgi Parties in each case, that is, straight-line depreciation of assets over technical asset lives for the purposes of deriving a DORC value of assets, and accelerated depreciation over substantially shorter asset lives for the purposes of forward-looking depreciation of assets. The Regulator concluded that the use of different depreciation assumptions was unreasonable, and accelerated depreciation was applied in deriving revised estimates of DORC values of assets. This resulted in changes to depreciation allowances and the returns on capital, which in turn reduced the Total Revenue. The revised Total Revenue is indicated below under "Additional Considerations of the Regulator".

5.8.4 Additional Considerations of the Regulator

On the basis of analysis of the information provided by the Tubridgi Parties, the Regulator considers the Total Revenue proposed for the Tubridgi Pipeline System needs to be revised to reflect a revised Initial Capital Base of $16.943 million (section 5.4 of this Draft Decision) and a revised Rate of Return of 8.2 percent (pre-tax real) (section 5.6 of this Draft Decision). These changes affect the depreciation and the return on capital components of Total Revenue. The consequent changes to Total Revenue and the cost components are as follows.

Revised Total Revenue ($million at 30 June 1999)

Cost Category	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Return on capital	1.389	1.319	1.249	1.179	1.109
Depreciation	0.855	0.855	0.855	0.855	0.855
Non-Capital Costs	0.495	0.495	0.495	0.495	0.495
Total	**2.739**	**2.669**	**2.599**	**2.529**	**2.459**

The following amendment is required before the Access Arrangement will be approved.

Amendment 38

The Access Arrangement and Access Arrangement Information should be amended to reflect a Total Revenue requirement as follows.

Total Revenue ($million at 30 June 2000)

1999/00	2000/01	2001/02	2002/03	2003/04	Total
2.739	2.669	2.599	2.529	2.459	12.995

5.9 COST/REVENUE ALLOCATION AND REFERENCE TARIFF

5.9.1 Access Code Requirements

In determining Reference Tariffs, a Service Provider must determine (explicitly or implicitly) the costs or share of costs of pipeline operation that will be recovered from revenues from Reference Services and other services. Rules for the allocation of costs/revenues between services are provided in sections 8.38 to 8.43 of the Code.

Section 8.38 of the Code requires that Reference Tariffs should be designed to only recover that portion of Total Revenue which includes:

(a) all of the Total Revenue that reflects costs incurred (including capital costs) that are directly attributable to the Reference Service; and

(b) a share of the Total Revenue that reflects costs incurred (including capital costs) that are attributable to providing the Reference Service jointly with other Services, with this share to be determined in accordance with a methodology that meets the objectives set out in section 8.1 of the Code and is otherwise fair and reasonable.

Section 8.39 of the Code provides for the Regulator to require a different methodology to be used for cost/revenue allocation than may have been proposed by a Service Provider in an Access Arrangement pursuant to section 38 of the Code. However, if such a requirement is proposed, the Regulator must provide a detailed explanation of the methodology that is required to be used.

Section 8.40 of the Code addresses the allocation of Costs/Revenue between reference Services and Rebatable Services. A Rebatable Service occurs where a portion of any revenue realised from sales of service is rebated to Users (either through a reduction in the tariff or through a direct rebate to the relevant User or Users). A Rebatable Service is relevant where:

(a) there is substantial uncertainty regarding expected future revenue from sales of that Service due to the nature of the Service and/or the market for that Service; and

(b) the nature of the Service and the market for that Service is substantially different to any Reference Service and the market for that Reference Service.

If a Reference Service is provided jointly with a Rebatable Service, then all or part of the Total Revenue that would have been recovered from the Rebatable Service under section 8.38 of the Code (if that service was a Reference Service) may be recovered from the Reference Service provided that an appropriate portion of any revenue realised from sales of any such Rebatable Service is rebated to Users of the Reference Service (either through a reduction in the Reference Tariff or through a direct rebate to the relevant User or Users). The structure of such a rebate mechanism should be determined having regard to the following objectives:

(a) providing the Service Provider with an incentive to promote the efficient use of capacity, including through the sale of Rebatable Services; and

(b) Users of the Reference Service sharing in the gains from additional sales of services, including from sales of Rebatable Services.

Section 8.41 provides a Service Provider with discretion to adopt alternative approaches to cost/revenue allocation subject to any approach adopted having substantially the same effect as the approach outlined in section 8.38 and 8.40 of the Code.

Section 8.42 relates to the allocation of costs/revenue between Users. This section requires that, subject to provisions for prudent discounts in section 8.43 of the Code, the Reference Tariff be designed such that the proportion of Total Revenue recovered from a actual or forecast sales of a Reference Service to a particular User of that service is consistent with the principles described in section 8.38 of the Code.

Section 8.43 of the Code provides for a Service Provider to give prudent discounts on Reference Tariffs or Equivalent Tariffs for Non Reference Services in particular circumstances. A User receiving a discount would be paying a proportion of Total Revenue that is less than the proportion that would be paid by the User under the principles of sections

8.38 and 8.40 of the Code. Section 8.43 of the Code provides for such a discount to be given to a User if:

(a) the nature of the market in which a User or Prospective User of a Reference Service or some other Service operates, or the price of alternative fuels available to such a User or Prospective User, is such that the Service, if priced at the nearest Reference Tariff (or, if the Service is not a Reference Service, at the Equivalent Tariff) would not be used by that User or Prospective User; and

(b) a Reference Tariff (or Equivalent Tariff) calculated without regard to revenues from that User or Prospective User would be greater than the Reference Tariff (or Equivalent Tariff) if calculated having regard to revenues received from that User or Prospective User on the basis that it is served at a price less than the Reference Tariff (or Equivalent Tariff).

The effect of (b), above, is to require that a discount may only be provided to a User if the incremental revenue from that User exceeds the incremental cost of providing a service to that User, and hence the incremental revenue still makes some contribution to the joint costs of providing pipeline services.

In this situation, the proportion of Total Revenue that comprises the Discount may be recovered from other Users of the Reference Service or some other service or services in a manner that the Regulator is satisfied is fair and reasonable.

5.9.2 Access Arrangement Proposal

Cost/Revenue Allocation

The allocation of Total Revenue across services provided in respect of the Tubridgi Pipeline System is described in sections 5.1 and 6.2.3 of the Access Arrangement Information.

For the purposes of calculating a Reference Tariff for the Haulage Reference Service, the Tubridgi Parties assumed that all forecast gas transportation in the Tubridgi Pipeline System would occur as a Haulage Reference Service. Total Revenue was thus allocated uniformly across all units of forecast gas transportation.

No explicit consideration was given to, or forecasts provided for, gas transportation occurring as Negotiated Services. The Tubridgi Parties have proposed that Negotiated Services comprise Rebatable Services.

Reference Tariff Determination

The Reference Tariff for the Haulage Reference Service is specified as being made up of two charges:

i. a fixed charge on booked MDQ; and

ii. a variable charge per GJ of throughput.

These charges were set at constant levels in real terms for the duration of the Access Arrangement Period. The stated reason for setting tariffs at a constant real level was to avoid a substantial increase in tariffs over the Access Arrangement Period that would occur if a Reference Tariff was set for each year to recover the Total Revenue for that year. This rise in the Reference Tariff would occur as a result of a forecast decline in throughput over the Access Arrangement Period, and hence a recovery of fixed costs from fewer "units" of gas transportation.

Quantity forecasts indicated in the Access Arrangement Information are as follows.

Tubridgi Parties' forecast of gas throughput

Year	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
Throughput (TJ)	11,654	10,440	6,178	2,751	1,095

The Tubridgi Parties determined the Reference Tariff by the following procedure.

- Calculation of the net present value of Total Revenue for the whole of the Access Arrangement Period, being the discounted sum of the real value of Total Revenue for each year of the Access Arrangement Period that covers the costs of return to capital, depreciation and Non-Capital Costs.

- Determination of the MDQ charge and throughput charge that would return the same net present value of Total Revenue under the following assumptions:

  ii. a recovery of 80 percent of Total Revenue by the MDQ charge and 20 percent of Total Revenue by the throughput charge;

  ii. a load factor of 77 percent of booked MDQ; and

  ii. an assumed inflation rate of 2.5 percent.

The proposed MDQ and throughput charges are indicated as follows, together with an average total tariff per unit of gas transported (assuming the 77 percent load factor as used in the tariff calculation).

Tubridgi Parties' proposed Reference Tariff

MDQ Charge ($/GJ of MDQ/day)	**Commodity Charge ($/GJ of throughput)**
$0.322/GJ	$0.105/GJ

The Tubridgi Parties propose that the charges making up the Reference Tariff be inflated annually by a factor of one plus the percentage change in the CPI, where the percentage change in the CPI relates to the change in the CPI between the March quarter in the current year and the March quarter in the previous year.

Rebatable Service

The Access Arrangement makes provision for Negotiated Services to be Rebatable Services within the meaning of section 8.40 of the Code. Under the proposed terms of section 3.2.5 of the Access Arrangement, revenue in excess of $350,000 in a financial year from Negotiated Services would be shared equally between the Tubridgi Parties and Users of the Reference Service, subject to the Tubridgi Parties receiving in excess of the following amounts of revenue from the Provision of the Reference Service.

Proposed threshold revenue from Reference Services before rebates become payable

Year	1999/00	2000/01	2001/02	2002/03	2003/04
Threshold revenue (nominal $million)	6.102	5.598	3.398	1.551	0.633

These threshold revenues for each year correspond to the expected revenue given the Tubridgi Parties' proposed Reference Tariff and assumptions as to gas quantities.

5.9.3 Submissions from Interested Parties

Magnitude of Reference Tariff

- Office of Energy

The Office of Energy considers that the Reference Tariff proposed by the Tubridgi participants is higher than appropriate and may unreasonably discourage downstream uses or consumers of gas. The Office of Energy considers that the proposed Reference Tariff may also unreasonably discourage developments in the upstream gas industry. In his decision for continued coverage of the Tubridgi Pipeline the WA Minister for Energy considered that access to the Tubridgi Pipeline is likely to promote competition amongst gas producers by encouraging exploration and the development of additional gas fields in the Carnarvon Basin. The Office of Energy considers that the level of the proposed Reference Tariffs would reduce that likelihood.

Section 8.1 of the Code requires that a Reference Tariff and Reference Tariff Policy be designed to achieve a range of specified objectives, including the provision of the Service Provider with an opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service. In contemplating the Reference Tariff and Reference Tariff Policy proposed by the Tubridgi Parties, the Regulator considered compliance with these objectives. Whether or not the Reference Tariff is sufficiently high to discourage development in the upstream gas industry was not an explicit consideration of the Regulator.

In assessing the Access Arrangement, the Regulator made revisions to the Initial Capital Base and the Rate of Return proposed by the Tubridgi Parties. This assessment has given rise to reductions in the Total Revenue for the Tubridgi Pipeline System (as indicated in section 5.8 of this Draft Decision). In addition, a revised throughput forecast has further reduced the Reference Tariff (as indicated below under Additional Considerations of the Regulator").

Tariff Structure

- Office of Energy

  The Tubridgi Parties have elected to adopt a structure whereby 80 percent of the Haulage Reference Service tariff is based on MDQ booked capacity, and the remaining 20 percent of the tariff is based on daily throughput. The Office of Energy considers that in terms of encouraging the utilisation of the Tubridgi Pipeline System it may be beneficial if the initial tariff structure is based on a higher proportion of the throughput charge, with no penalties for overruns, and that the currently proposed structure (80%:20% capacity : throughput charge) is introduced at the time of the review of the initial Access Arrangement.

The Regulator considers that the structure of Reference Tariffs should be a matter of commercial discretion for a Service Provider, subject to any proposed tariff structure not being unreasonably inconsistent with any relevant criteria of efficiency and equity.

With the Tubridgi Pipeline System, the almost entirely fixed nature of costs underlying Total Revenue means that a Reference Tariff structure comprised predominantly of fixed charges would meet efficiency criteria. This is consistent with the 80 percent fixed charge and 20 percent quantity charge proposed by the Tubridgi Parties. Furthermore, the proposed tariff structure is similar to tariff structures for other Australian transmission pipelines. On this basis, the Regulator does not consider there to be any grounds for requiring changes to the proposed tariff structure.

Rebatable Services

- AlintaGas Trading

  The Tubridgi Parties propose to provide a rebate to Reference Service Users on revenue the Tubridgi Parties earn in excess of $350,000 per annum earned from the provision of Negotiated Services. AlintaGas Trading would be interested to know how the revenue limit of $350,000 was determined. With the rebatable revenue to be shared equally between the Tubridgi Parties and the Users, there is no apparent reason why all revenue from Negotiated Services should not be rebatable.

In further information provided to the Regulator, Origin Energy has indicated that the revenue requirement of $350,000 before rebates became payable was selected because it represents approximately 10 percent of the Tubridgi Pipeline System average annual revenue over the Access Arrangement Period. In the Tubridgi Parties' opinion, although the figure of 10 percent is somewhat arbitrary, it represents an appropriate balance between providing the Service Provider with an incentive to promote the efficient use of capacity (and to recover the direct cost of establishing and providing Negotiated Services) whilst at the same time permitting Users of the Reference Service to share in the gains from additional sales of services. The Tubridgi Parties noted that the incentive mechanism proposed by Epic Energy in its Access Arrangement for the Moomba to Adelaide Pipeline only takes effect once additional revenue exceeds target revenue by approximately 10 percent, although this provision of this Access Arrangement has been removed in a subsequent version.[50]

The Regulator's considerations in regard to the rebate provisions are detailed below under "Additional Considerations of the Regulator". The Regulator considers that provision for threshold level of revenue to be obtained from Negotiated Services prior to a rebate being

[50] Access Arrangement prepared by Epic Energy South Australia Pty Ltd. The Tubridgi Parties had refereed to a version dated 1 April 1999 that was subsequently replaced by a revised version dated 2 March 2000.

payable is reasonable in the circumstances of the Tubridgi Pipeline given the current low level of use of the pipeline assets and the potential long-term benefits to Users of promoting use of the pipeline system. However, the Regulator is of the opinion that several incentive problems arise is respect of the incentive provisions for the payments of rebates from revenue derived from the sale of Negotiated Services. This matter is further addressed in section 5.10 of this Draft Decision in relation to Incentive Mechanisms. The Regulator will require amendment of the Access Arrangement to address these incentive problems, which may include changing the proposed threshold revenue from Negotiated Services before rebates become payable.

- AlintaGas Trading

> If the terms and conditions of a Negotiated Service are not materially different to those of a Reference Service, then the Negotiated Service should probably still be classified as a Reference Service for the purposes of distributing any rebatable revenue. Terms and conditions that might be considered to be material are those associated with issues such as price, contract term and curtailment priority.

Origin Energy provided additional information to the Regulator in response to this submission indicating that while the suggestion from AlintaGas does have merit, it introduces difficulties associated with determining actually what constitutes a "material" difference between a Reference Service and a Negotiated Service. It was indicated to the Regulator that rather that attempt to define a material difference, the Tubridgi Parties believe it is better to maintain the existing distinction based on the definition of Reference Service as it stands. For the sake of containing administrative costs, the Regulator concurs with this view.

- CMS Gas Transmission Australia

> The Tubridgi Access Arrangement states that as revenue from Negotiated Services has not been included in the revenue base, a Negotiated Services Rebate to Forward Haul Reference Service Users will occur to the extent that the predicted revenue is exceeded (Access Arrangement clause 3.2.5). Clarification may be required that the revenue base thus defined and from which the Reference Tariff is determined, comprehensively captures all revenue receipts generated by the subject pipelines.

In accordance with the provisions of the Code, the Tubridgi Parties determined a Reference Tariff from a cost base and not a revenue base. The Reference Tariff was derived by determining a Total Revenue requirement as a sum of costs incurred by the Tubridgi Parties, including a rate of return on assets.

The methodology used by the Tubridgi Parties for allocation of Total Revenue involved an assumption that all forecast gas transmission through the Tubridgi Pipeline System would occur as the Haulage Reference Service. This is consistent with the guidelines set out in section 8.38 of the Code, despite the possibility that gas transmission by the Tubridgi Parties on their own behalf may not be explicitly charged for at the Reference Tariff and revenue from such transmission is only notional for the purposes of determining of Reference Tariffs.

The Regulator accepts in principle the proposal to establish a threshold revenue before any rebate becomes payable from revenue received from Negotiated Services, although there are some concerns as to the incentive effects created by the proposal to consider only revenue from Reference Services in this threshold. However, it is conceivable that gas transmission undertaken by the Tubridgi Parties on their own behalf would not be undertaken as a Reference Service with a commensurate revenue stream. The Regulator will require that the Access Arrangement be amended to ensure that gas transmission undertaken by the Tubridgi Parties on their own behalf will be assumed, for regulatory purposes, to have been undertaken as the Haulage Reference Service with a notional revenue commensurate with the Reference Tariffs. These matters are further discussed below under "Additional Considerations of the Regulator".

5.9.4 Additional Considerations of the Regulator

Forecast Gas Quantities

The Tubridgi Parties provided forecasts of gas quantities to be shipped through the Tubridgi Pipeline System in section 12.3 of the Access Arrangement Information. The forecasts were made on the basis of forecasts of gas production by the Griffin Joint Venture and CMS Gas Transmission.

Subsequent to the Tubridgi Parties deriving Reference Tariffs and submitting the Arrangement, additional information has come to the attention of the Regulator that, in the Regulator's opinion, necessitates a revision of forecast quantities of gas throughput for the Access Arrangement Period.

- The contract for gas transmission with CMS Gas Transmission has terminated, resulting in a reduction in quantities of gas shipped by 1,095 TJ/annum from 2000/01 onwards.

- The Griffin Joint Venture has increased its forecasts of gas production and transmission through the Tubridgi Pipeline System subsequent to the drilling of successful oil wells and the consequent higher projected production of associated gas. Furthermore, the Griffin Joint Venture has entered into an agreement with Epic Energy for delivery of untreated gas to the Dampier to Bunbury Natural Gas Pipeline, allowing for the savings of gas that would otherwise have been used for processing. BHP Petroleum, on behalf of the Griffin Joint Venture, has provided an updated forecast of gas transmission through the Tubridgi Pipeline System.

In view of the above, the Regulator will require that the Tubridgi Parties submit a revised forecast of gas throughput. For the purposes of this Draft Decision, the Regulator has used a revised forecast of gas throughput based on the anticipated changes resulting from the termination of the contract with CMS Gas Transmission and revised production forecasts from the Griffin Joint Venture. This revised forecast is as follows.

Revised forecast of gas throughput

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004	Total
Original throughput forecast (TJ)	11,654	10,440	6,178	2,751	1,095	32,118
Revised throughput forecast (TJ)	12,314	12,124	7,912	6,584	6,222	45,156

The following amendment is required before the Access Arrangement will be approved.

Amendment 39

The Access Arrangement and Access Arrangement Information should be amended to reflect updated throughput forecasts for the Tubridgi Pipeline System and to substantiate the updated forecast.

Reference Tariffs

The Regulator revised the proposed Reference Tariff to reflect adjustments made in this Draft Decision to Total Revenue (as a result of changes to the Initial Capital Base and Rate of Return) and assumptions as to a revised forecast of gas throughput.

The Regulator has also taken into account the impact of the goods and services tax in making adjustments to the Reference Tariff. The Regulator is of the view that it is appropriate to accommodate the pass through of the goods and services tax in the Reference Tariffs as they will be set out in the revised Access Arrangement. In view of this, the Tubridgi Parties have proposed to the Regulator that the goods and services tax be passed through to Reference Tariffs at a rate of 10 percent of the goods-and-services-tax exclusive tariff. For the purposes of the Draft Decision the Regulator has assessed Reference Tariffs on the basis of the 10 percent pass through of the goods and services tax as proposed by the Tubridgi Parties. However, prior to the final approval of a Reference Tariff, the Regulator will require the Tubridgi Parties to submit an independent audit certificate verifying that the percentage increase in the Reference Tariff to account for the net effect of the goods and services tax and related taxation changes has been calculated according to generally accepted accounting principles and/or accounting standards.

A comparison of the proposed and revised Reference Tariff is as follows.

Proposed and revised Reference Tariff (dollar values at 30 June 1999)

	MDQ Charge ($/GJ of MDQ/day)	Commodity Charge ($/GJ throughput)	Indicative Average Tariff at 100% load factor ($/GJ throughput)
Proposed Tariff	0.322	0.105	0.427
Revised Tariff (excl. goods and services tax)	0.173	0.056	0.229
Revised Tariff (incl. goods and services tax)	0.190	0.062	0.252

The following amendment is required before the Access Arrangement will be approved.

> Amendment 40
>
> Should the revised throughput forecast for the Tubridgi Pipeline System be consistent with that assumed by the Regulator for the purposes of this Draft Decision, the Access Arrangement should be amended to provide for the Reference Tariff for the Haulage Reference Service in 1999/2000 to comprise an MDQ charge of $0.190 per GJ of MDQ and a commodity charge of $0.062 per GJ of gas throughput, inclusive of the goods and services tax.

Rebatable Services

The Access Arrangement makes provision for Negotiated Services to be Rebatable Services within the meaning of section 8.40 of the Code. Half of the revenue derived from Negotiated Services in a financial year would be paid to Users of the Reference Service subject to:

- earning of revenue in excess of $350,000 in that financial year from Negotiated Services; and
- the Tubridgi Parties earning minimum threshold levels of revenue from the Reference Service in that financial year, where the threshold levels are equal to the expected revenue for each year at the commencement of the Access Arrangement Period and determined on the basis of the Tubridgi Parties' proposed Reference Tariff and assumptions as to gas quantities.

Other Access Arrangements for transmission pipelines in Australia have varying provisions for Rebatable Services and there is no common or standard practice. For example, the proposed Access Arrangement for the Moomba to Sydney Pipeline[51] provides for 75 percent of revenue generated from Rebatable Services (net of incremental capital and operating costs attributable to these services) to be distributed to Users of Reference Services. The proposed Access Arrangement for the Moomba to Adelaide Pipeline System[52] includes more complex provisions for rebates whereby revenue derived from a rebatable interruptible service (IT Service) may be partially distributed to another pipeline User that is meeting the cost of delivery facilities through which gas is delivered under the IT Service.

In view of the absence of common or standard provisions relating to Rebatable Services the Regulator considered the proposed provisions for the Rebatable Service in the specific context of the Tubridgi Pipeline System and the objectives for a Rebatable Service set out in section 8.40 of the Code:

(a) providing the Service Provider with an incentive to promote the efficient use of capacity, including through the sale of Rebatable Services; and

(b) Users of the Reference Service sharing in the gains from additional sales of services, including from sales of Rebatable Services.

[51] East Australian Pipeline Limited, 5 May 1999.

[52] Epic Energy South Australia Pty Ltd, 2 March 2000. Note that an earlier version of the proposed Access Arrangement for this pipeline (1 April 1999) contained a different rebate mechanism.

In so far as provisions for Rebatable Services relate to an incentive mechanism for the Service Provider, the Regulator also took into account the objectives for an incentive mechanism as set out in section 8.46 of the Code, in particular:

8.46 (a) to provide the Service Provider with an incentive to increase the volume of sales of all services, but to avoid an artificial incentive to favour the sale of one service over another; and

8.46 (c) to provide the Service Provider with an incentive to develop new services in response to the needs of the market for services.

The provisions of the Access Arrangement relating to the Rebatable Service would provide an incentive for the Tubridgi Parties to promote the use of capacity for Negotiated Services through the ability to capture the first $350,000 revenue from provision of Negotiated Services (and greater than this amount if less than the projected revenue is obtained from the Reference Service), and one half of revenue from Negotiated Service thereafter, which is revenue over and above the costs of service provision. The strong incentive to provide Negotiated Services is desirable given the possibility, for example, for such a service to be sought for the back-haul of gas from the DBNGP to Onslow through the Tubridgi Pipeline System. This incentive is also consistent with the objective for an incentive mechanism set out in section 8.46(c) of the Code.

Notwithstanding the desirability of the incentive to provide Negotiated Services, there are two potential incentive problems with the provisions for the payment of rebates.

Firstly, there is an incentive for the Tubridgi Parties to supply Negotiated Services in place of the Reference Service. This would have the effect of reducing the revenue obtained from the Reference Service and allowing a greater total revenue to be achieved before any rebate is payable. This artificial incentive to provide one service in preference to another is contrary to the objective for an incentive mechanism set out in section 8.46(a) of the Code.

Secondly, given the status of gas production in the gas fields supplying gas to the Tubridgi Pipeline System, there may be substantial year to year differences between forecast and realised throughput. Under the proposed provisions for the payment of rebates, the rebates are calculated on the basis of revenues in each financial year. Consequently, there would be an incentive for the Tubridgi Parties to seek to alter actual gas throughputs across financial years to minimise rebate liabilities. This may be contrary to the efficient use of pipeline capacity, and hence contrary to the objective for a Rebatable Service set out in section 8.40(a) of the Code.

These incentive problems are further addressed in relation to Incentive Mechanisms in section 5.10 of this Draft Decision.

An additional potential problem with the proposed provisions for Rebatable Services arises as a result of a significant proportion of the projected throughput of the Tubridgi Pipeline System comprising gas transported by the Tubridgi Parties on their own behalf. While this has been assumed to constitute transportation under the Reference Service for the purposes of determining the Reference Tariff, there may not be any revenue explicitly collected for this gas transportation. Unless provision is made to account for notional revenue to be recovered for gas transportation by the Tubridgi Parties on their behalf, the threshold levels of revenue for payment of rebates may not be reached despite gas throughput exceeding the throughput quantities forecast for the purposes of the Access Arrangement. Such provision has not been made in the proposed Access Arrangement.

The following amendment is required before the Access Arrangement will be approved.

Amendment 41 The Access Arrangement should be amended to the effect that, for regulatory purposes, gas transportation undertaken by the Tubridgi Parties on their own behalf is assumed to return a revenue as if this gas transportation was undertaken as a Haulage Reference Service.

5.10 REFERENCE TARIFF VARIATION AND INCENTIVE MECHANISMS

5.10.1 Access Code Requirements

The Code addresses variation in Reference Tariffs over the Access Arrangement Period in terms of two general matters:

i. variation in Reference Tariffs at the discretion of the Service Provider and according to principles such as a predetermined price path or realised cost and sales outcomes for the Service Provider; and

ii. within the scope of (i), variation of Reference Tariffs according to principles of an Incentive Mechanism.

The provisions of the Code relating to these matters are outlined as follows.

Variation in Reference Tariffs at the Discretion of the Service Provider

Section 8.3 of the Code provides for the Service Provider to have discretion as to the manner in which Reference Tariffs vary across an Access Arrangement Period, subject to the Regulator being satisfied that such variation is consistent with the objectives for Reference Tariffs contained in section 8.1 of the Code. Section 8.3 of the Code goes on to indicate that, for example, a Reference Tariff may be varied across the Access Arrangement Period by means of:

(a) a price path approach, whereby a series of Reference Tariffs are determined in advance for the Access Arrangement Period to follow a path that is forecast to deliver a revenue stream calculated consistently with the principles in section 8 of the Code, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period;

(b) a cost of service approach, whereby the Tariff is set on the basis of the anticipated costs of providing the Reference Service and is adjusted continuously in light of actual outcomes (such as sales volumes and actual costs) to ensure that the Tariff recovers the actual costs of providing the Service; or

(c) variations or combinations of these approaches.

Incentive Mechanism

Sections 8.44 to 8.46 of the Code state the principles for establishing an Incentive Mechanism within the Reference Tariff Policy and the objectives which the Incentive Mechanism should seek to meet.

Section 8.44 of the Code states that a Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism that permits the Service Provider to retain all, or a share of, any returns to the Service Provider from the sale of a Reference Service during an Access Arrangement Period that exceeds the level of returns expected at the beginning of the Access Arrangement Period (an Incentive Mechanism), particularly where the additional returns are attributable (at least in part) to the efforts of the Service Provider. Such additional returns may result, amongst other things, from lower Non-Capital Costs or greater sales of Services than forecast.

Section 8.45 of the Code provides that an Incentive Mechanism may include (but is not limited to) the following:

(a) specifying the Reference Tariff that will apply during each year of the Access Arrangement Period based on forecasts of all relevant variables (and which may assume that the Service Provider can achieve defined efficiency gains) regardless of the realised values for those variables;

(b) specifying a target for revenue from the sale of all Services provided by means of the Covered Pipeline, and specifying that a certain proportion of any revenue received in excess of that target shall be retained by the Service Provider and that the remainder must be used to reduce the Tariffs for all Services provided by means of the Covered Pipeline (or to provide a rebate to Users of the Covered Pipeline); and

(c) a rebate mechanism for Rebatable Services pursuant to section 8.40 of the Code that provides for less than a full rebate of revenues from the Rebatable Services to the Users of the Reference Service.

Section 8.46 of the Code states that an Incentive Mechanism should be designed with a view to achieving the following objectives:

(a) to provide the Service Provider with an incentive to increase the volume of sales of all Services, but to avoid providing an artificial incentive to favour the sale of one Service over another;

(b) to provide the Service Provider with an incentive to minimise the overall costs attributable to providing those services, consistent with the safe and reliable provision of such services;

(c) to provide the Service Provider with an incentive to develop new services in response to the needs of the market for services;

(d) to provide the Service Provider with an incentive to undertake only prudent New Facilities Investment and to incur only prudent Non-Capital Costs, and for this incentive to be taken into account when determining the prudence of New Facilities Investment and Non-Capital Costs for the purposes of sections 8.16 and 8.37 of the Code; and

(e) to ensure that Users and Prospective Users gain from increased efficiency, innovation and volume of sales (but not necessarily in the Access Arrangement Period during which such increased efficiency, innovation or volume of sales occur).

5.10.2 Access Arrangement Proposal

The Tubridgi Parties have addressed Incentive Mechanisms in clause 3.2.3 of the Access Arrangement and section 6.2 of the Access Arrangement Information. Two incentive mechanisms are proposed:

i. the Total Revenue requirement and the Reference Tariff will be held constant, in real terms, over the Access Arrangement Period regardless of realised Non-Capital Costs and revenue; and

ii. any reductions in Non-Capital Costs achieved within the Access Arrangement Period will be carried through to the next Access Arrangement Period and the savings shared with Users in the subsequent Access Arrangement Period through a reduction in the Total Revenue requirement.

The Tubridgi Parties have indicated that both of these initiatives are subject to the Tubridgi Parties continuing to manage and operate the Tubridgi Pipeline System in accordance with accepted industry practice. This is interpreted by the Regulator to mean that the Tubridgi Parties wish to maintain the right to increase Reference Tariffs or to not carry cost reductions through to the next Access Arrangement Period, if either of these actions are necessary to recover increased costs incurred in managing and operating the Tubridgi Pipeline System in accordance with accepted industry practice.

The Tubridgi Parties have proposed that these elements of the Access Arrangement be Fixed Principles within the meaning of section 8.47 of the Code, implying that the Reference Tariff would not be subject to change within the Access Arrangement Period without agreement of the Tubridgi Parties, regardless of realised outcomes for Non-Capital Costs and Revenue. It is noted, however, that the clause 9.3 of the Access Arrangement makes provision for a trigger event for review of the Access Arrangement subject to the outcomes of an independent review in 2002 of forecast demand for services. Such a review may reduce the benefits of increased throughput that would be able to be captured by the Service Provider, unless the Access Arrangement makes specific provision for this to occur.

5.10.3 Submissions from Interested Parties

Inflation Adjustment of Tariffs

- Western Power

  The Reference Tariff will change each year by the percentage change in the CPI. Western Power considers that full indexation of the Reference Tariff based upon future changes in the CPI is not appropriate because, it does not reflect the cost structure of the Tubridgi Pipeline System. It is a fact that pipeline operations are capital intensive, with most costs (typically 80%) relating to capital expenses. Operating and maintenance costs represent only a small portion of the overall costs of a pipeline. The adoption of a full CPI tariff adjustment is inappropriate since the major portion of pipeline costs is not related to the CPI.

Most costs of the Tubridgi Pipeline System are capital costs: a return on capital and depreciation. It is generally accepted regulatory practice in Australia that both of these costs (and hence the associated revenue returns) should reflect the real (ie. inflation adjusted) value of capital assets. There are two general methods to achieve this in the determination of Reference Tariffs.

Firstly, Total Revenue can be determined in real terms such that values for capital costs, and hence the resultant Reference Tariffs, do not incorporate a nominal escalation of the Capital Base to accommodate inflation. In this case, it is appropriate that Reference Tariffs are then escalated for inflation so as to maintain the value of returns to Capital and Depreciation in real terms.

Secondly, Total Revenue can be determined in nominal terms such that values for capital costs incorporate an escalation for inflation. In this case, any year to year variation of Reference Tariffs should recognise that the Reference Tariffs already accommodate a projected level of inflation over the Access Arrangement Period. Some inflation adjustments may be made, however, to reflect differences between realised inflation rates and the inflation rates assumed for the purposes of calculating Reference Tariffs.

The Tubridgi Parties utilised the first of these general methodologies for the determination of Reference Tariffs. The Regulator also used this methodology in assessing and revising the proposed Reference Tariffs. The Regulator therefore considers it generally appropriate for the Reference Tariffs to be escalated by the rate of change in the CPI to accommodate inflation.

Incentive Mechanism

- CMS Gas Transmission Australia

  CMS supports in principle the Incentive Mechanisms outlined in Clause 3.2.3 of the Access Arrangement as being compliant with the requirements of the Code and appropriate to provide longer term certainty for both Users and Service Providers, as well as providing ongoing incentives for the latter to further improve already comparatively lean costs of operation.

- Office of Energy

  The Code encourages the inclusion in Access Arrangements of mechanisms for providing the Service Provider with incentives to improve the efficiency of pipeline operation. Incentive mechanisms typically provide for a sharing of the benefits of efficiency gains between the Service Provider and Users both within an Access Arrangement Period (such as through a CPI–X incentive mechanism) and across Access Arrangement Periods.

  The Office of Energy considers that the currently proposed incentive mechanism does not provide for a sharing of the benefits of efficiency gains between the Service Provider and Users within the initial Access Arrangement Period. Therefore, the Office of Energy suggests that the Regulator consider requiring amendments of the Access Arrangement to provide for an alternative CPI-X incentive mechanism. In addition it should be considered whether or not the incentive mechanism should apply to the capital costs, given the associated costs cannot be “minimised”, or it should only apply to non-capital costs.

The Incentive Mechanism proposed by the Tubridgi Parties in clause 3.2.3 of the Access Arrangement is consistent with the price path approach to the determination of Reference tariffs. Under this approach, Reference Tariffs are set at pre-determined levels over the Access Arrangement Period. The benefits of cost savings achieved in the provision of services within the Access Arrangement Period would accrue to the Service Provider, providing an incentive for efficiency gains and the reduction in costs. This arrangement is consistent with the principles for an Incentive Mechanism set out in sections 8.44 and 8.45(a) of the Code. Furthermore, the provision for the benefits of efficiency gains made in the Access Arrangement Period to be reflected in the Total Revenue requirement for the next Access Arrangement Period nominally meets the objective set out in section 8.46(e) of the Code, which is that both the Service Provider and Users should gain from increased efficiency, but not necessarily in the Access Arrangement Period during which the increase in efficiency was achieved.

In considering the adequacy of the Incentive Mechanism proposed by the Tubridgi Parties, the Regulator considered whether the price path methodology provides a sufficient level of incentive for efficiency gains in operation of the Tubridgi Pipeline System, or whether a further incentive mechanism should be included in the Access Arrangement, such as a CPI-X incentive mechanism in the year to year variation of the Reference Tariff that incorporates an "X" value reflecting productivity increases over and above those forecast by the Service Provider for the purposes of determining Reference Tariffs.

Regulatory decisions on Access Arrangements for gas pipelines and distribution systems in the eastern states of Australia have generally accepted a price path approach to the determination of Reference Tariffs to, in itself, provide sufficient incentive for Service Providers to increase throughput and to seek cost savings and efficiency gains.[53] While the incentive mechanisms in some Access Arrangements have included CPI–X constraints on year to year variations in tariffs, the value of the X factor has typically not reflected productivity improvements beyond those already forecast by the Service Provider and incorporated into cost and demand forecasts. Rather, the X value has been derived as a means of achieving a yearly adjustment to tariffs so that there is a smooth path of tariff changes over an Access Arrangement Period while preserving the net present value of a target revenue stream.

In two previous Draft Decisions for Western Australian pipelines,[54] the Regulator has contemplated the inclusion of CPI–X incentive mechanisms into the respective Access Arrangements, with an X value reflecting cost reductions and efficiency gains in excess of those incorporated into the Service Providers' cost forecasts. Such an incentive mechanism may be justified if there are prospects for additional productivity gains by Service Providers and it is considered reasonable that the benefits of these productivity gains should be shared between the Service Providers and Users within the Access Arrangement Period.

In view of the general stance being taken by Australian regulators in respect of Incentive Mechanisms, the Regulator considers that it is not appropriate for the forthcoming Access Arrangement Period to impose a CPI–X incentive mechanism in respect of the Tubridgi Parties, at least for the forthcoming Access Arrangement Period. It is thus implicitly accepted that the price path methodology for determination of Reference Tariffs provides sufficient incentive for efficiency gains and increases in throughput, and that any sharing of

[53] For example, IPART, September 1999, Access Arrangement for Great Southern Energy Gas Networks Pty Limited Natural Gas Distribution System in Wagga Wagga; ACCC, September 1999, Draft Decision Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline; ACCC, October 1998, Final Decision Access Arrangements for the Principal Transmission System and Western Transmission System.

[54] Independent Gas Pipelines Access Regulator Western Australia, October 1999, Draft Decision: Access Arrangement Parmelia Pipeline; Independent Gas Pipelines Access Regulator Western Australia, October 1999, Draft Decision: Access Arrangement Mid-West and South-West Gas Distribution Systems.

benefits between the Service Provider and Users would not occur until the next Access Arrangement Period.

5.10.4 Additional Considerations of the Regulator

Definition of the CPI

Clause 3.2.1 of the Access Arrangement provides for the Reference Tariff to change each year by the percentage change in the CPI. The CPI is defined in clause 10 of the Access Arrangement as the Consumer Price Index (All Groups Weighted Average for the Eight Capital Cities) as published by the Australian Bureau of Statistics or its successor or, if that Consumer Price Index is not published for any reason, whatever index the Tubridgi Parties determine from time to time is reasonably equivalent to that Consumer Price Index.

The Regulator is of the opinion that the CPI measure used for the inflation escalation of Reference Tariffs should be exclusive of the effects of the goods and service tax. The Regulator's preferred method for adjusting for the inflationary effects of the goods and services tax is to correct the CPI measure, as published by the Australian Bureau of Statistics, by the forecast inflationary effect of the goods and services tax as determined by the Commonwealth Treasury.[55] The Access Arrangement should be amended to this effect.

The following amendment is required before the Access Arrangement will be approved.

Amendment 42 The Access Arrangement should be amended such that for the purposes of setting the Reference Tariff for 2001/02, the CPI measure for 2000/01 should be reduced by 2.75 percent to account for the impact of the goods and services tax.

Incentives for Increasing Pipeline Throughput

In section 6.2 of the Access Arrangement Information, the Tubridgi Parties have proposed that the price path methodology for the determination of Reference Tariffs provides the Tubridgi Parties with appropriate incentives to reduce costs and maximise deliveries of gas within an Access Arrangement Period.

No provision is made in the Access Arrangement for the sharing between the Tubridgi Parties and Users of benefits of cost reductions within the Access Arrangement Period, although it is noted that clause 3.2.3.2 of the Access Arrangement provides for any reductions in Non-Capital Costs to be shared with Users over the subsequent Access Arrangement Period. The Regulator considers these proposed provisions to be consistent with the requirements of the Code and to be reasonable, at least for the initial Access Arrangement Period.

Provision is made in the Access Arrangement for the sharing between the Tubridgi Parties and Users of benefits of increased throughput over the Access Arrangement Period. The relevant provisions in the Access Arrangement are:

[55] Peter Costello, M.P., Treasurer of the Commonwealth of Australia, and John Fahey, M.P., Minister for Finance and Administration, May 2000. *2000-01 Budget Paper No. 1 Budget Strategy and Outlook 2000-01*, Statement 3 Part V: The Timing of Price Changes.

- the proposal for a review of the Access Arrangement to be triggered in the event that an independent assessment of demand in 2002 indicates that demand for services is likely to exceed 20 TJ/day for each day over any period of three consecutive months between 1 July 2002 and 30 June 2004 (clause 9.3 of the Access Arrangement, as discussed in section 4.8 of this Draft Decision); and

- the proposal for Negotiated Services to comprise Rebatable Services, where rebates to Users of the Reference Services are paid where revenue from Reference Services and Negotiated Services exceeds threshold amounts in any financial year (clause 3.2.5 of the Access Arrangement, as discussed in section 5.9 of this Draft Decision.

The Regulator is of the view that these provisions for sharing of benefits between the Tubridgi Parties and Users should be considered as part of an incentive mechanism and assessed against the objectives for an incentive mechanism as set out in section 8.46 of the Code.

As indicated in sections 4.8 and 5.9 of this Draft Decision, the Regulator has concerns as to several potential incentive problems arising from the proposed trigger event for review of the Access Arrangement, and the proposed provisions for payment of rebates from negotiated Services revenue. These potential incentive problems are as follows.

- A provision for triggering a review of the Access Arrangement where realised throughput exceeds forecast throughput by some threshold amount is probably not justified for the Tubridgi Pipeline System given the low revenues from gas transmission for this pipeline and the costs that would be incurred in reviewing the Access Arrangement.

- The provisions for rebates to be paid from revenues received from sale of Negotiated Services create an incentive for the Tubridgi Parties to supply Negotiated Services in preference to the Reference Service, which is contrary to the objective for an incentive mechanism set out in section 8.46(a) of the Code.

- The provision for the payment of rebates from Negotiated Services revenue potentially creates an incentive for the Tubridgi Parties to seek to alter actual gas throughputs across financial years to minimise rebate liabilities. This may be contrary to the efficient use of pipeline capacity, and hence contrary to the objective for a Rebatable Service set out in section 8.40(a) of the Code.

The Regulator will require that the Access Arrangement be amended to address these potential incentive problems. In the first instance, the Regulator will allow the Tubridgi Parties to propose suitable changes to the Access Arrangement. However, the Regulator suggests that it may be appropriate to have a rebate mechanism based on an excess of realised throughput or revenue over forecast throughput or revenue. This could negate the need for inclusion in the Access Arrangement of a trigger for review of the Access Arrangement in such circumstances as well as meeting the objectives of an incentive mechanism for increasing pipeline throughput and the sale of Non-Reference Services. For the purposes of containing the costs of regulation, the Regulator considers that a short Access Arrangement Period and/or the triggering of an early review of the Access Arrangement should be avoided where there exists suitable alternative mechanisms of accommodating uncertainty in throughput forecasts.

The following amendment is required before the Access Arrangement will be approved.

Amendment 43 Clause 3.2.5 (Rebate of Revenue from Negotiated Services) and clause 9.3 (Trigger Event) of the Access Arrangement should be amended to be consistent with the objectives for Rebatable Services and Incentive Mechanisms as set out in sections 8.40 and 8.46 of the Code.

6 FEES AND CHARGES OTHER THAN REFERENCE TARIFFS

6.1 INTRODUCTION

The Access Arrangement provides for the Tubridgi Parties to levy a range of fees and charges on Users and Prospective Users of services provided in respect of the Tubridgi Pipeline System. These fees and charges comprise:

- a Service Request application fee, levied on Prospective Users for lodgement of application form with the Tubridgi Operator (clause 2.4 of the Access Arrangement);
- an Overrun Charge, levied on Users whenever the quantity of gas delivered through any User Delivery Point to or for the account of the User on any Pipeline Day exceeds the MDQ for that User Delivery Point (clause 4.1 of the General Terms and Conditions);
- goods and services tax in respect of a taxable supply made by the Tubridgi Parties to a User (clause 16 of the General Terms and Conditions);
- charges levied on Users to recoup costs arising from taxes and imposts on the Tubridgi Parties either directly related to the service provided to particular Users or related only to provision of pipeline services *in toto* (clauses 17.1 and 17.2 of the General Terms and Conditions);
- reimbursement of the Tubridgi Parties on demand for any costs incurred by the Tubridgi Parties in connection with the preparation, negotiation, execution and delivery of the Agreement and payment of all stamp duty payable in any jurisdiction on or in respect of the Agreement or any document prepared or executed pursuant to the agreement (clause 34 of the General Terms and Conditions);
- a fee payable on application for a transfer of capacity, other than a Bare Transfer, or on application for a change of Delivery Points or Receipt Points (clause 6.4 of the Access Arrangement); and
- reimbursement of the Tubridgi Parties for costs incurred in assessing the technical and commercial feasibility of an application for a transfer of capacity, other than a Bare Transfer, or an application for a change of Delivery Points or Receipt Points (clause 6.4 of the Access Arrangement).

These fees and charges comprise a pecuniary impost on Users and Prospective Users in addition to service tariffs. For this reason, the Regulator considered that an assessment of fees and charges was necessary in evaluating the Access Arrangement.

6.2 ACCESS CODE REQUIREMENTS

The Code does not address the levying of fees and charges by a Service Provider on Users or Prospective Users other than through Reference Tariffs. Sections 3.1 to 3.20 of the Code, that outline the required scope of an Access Arrangement, do not explicitly require fees and charges to be specified. However, to the extent that fees and charges comprise part of the Terms and Conditions for provision of Reference Services, such matters may fall within the scope of section 3.6 of the Code. This section of the Code requires that an Access Arrangement include the terms and conditions on which the Service Provider will supply each Reference Service.

In considering the fees and charges arising in respect of a Service Agreement for a Reference Service, the Regulator gave attention to the requirements of section 3.6 of the Code that requires that the terms and conditions for provision of Reference Services must, in the Regulator's opinion, be reasonable. In respect of any fees and charges levied otherwise than under a Service Agreement for a Reference Service, the Regulator considered matters set out in section 2.24 of the Code:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users; and

(g) any other matters that the Relevant Regulator considers are relevant.

6.3 APPLICATION FEE

6.3.1 Access Arrangement Proposal

Clause 2.4 of the Access Arrangement provides for the Tubridgi Parties to charge an application fee of $1,000 for lodgement by a Prospective User of a request for a service.

6.3.2 Submissions from Interested Parties

No submissions made in respect of the Access Arrangement addressed the matter of the application fee.

6.3.3 Other Considerations of the Regulator

In assessing whether the charging of the application fee is a reasonable practice on the part of the Tubridgi Parties, the Regulator considered the practice of other Service Providers in respect of similar fees.

A summary of fee arrangements proposed or in place for lodgement of access requests with other Service Providers is summarised as follows from Access Arrangement documentation.

Service Provider	Access Fee Arrangements
Epic Energy – Moomba to Adelaide Pipeline System (Proposed Access Arrangement 2 March 2000)	Proposed non-refundable application fee of $5000 to be paid to the Service Provider on the day that a Request for Service is lodged
Envestra Limited – Mildura Pipeline (Access Arrangement 11 November 1999)	None.
East Australian Pipeline Limited – Moomba to Sydney Pipeline System (Proposed Access Arrangement 5 May 1999)	None.
N.T. Gas Pty. Limited – Amadeus Basin to Darwin Pipeline (Proposed Access Arrangement 25 June 1999)	None.
AGL Pipelines (NSW) Pty Limited – Central West Pipeline (Proposed Access Arrangement 31 December 1998)	None.
Envestra Limited – Riverland Pipeline (Proposed Access Arrangement 11 November 1999)	None.
CMS Gas Transmission Australia – Parmelia Pipeline (Proposed Access Arrangement 7 May 1999)	Proposed application fee of $10,000 able to be refunded at the discretion of the Service Provider.*

*The Draft Decision on this Access Arrangement required the Access Arrangement to be amended to remove provision for this application fee.

The Regulator identified only two Service Providers (Epic Energy – Moomba to Adelaide Pipeline System and CMS Gas Transmission Australia – Parmelia Pipeline) that propose to levy a fee resembling the application fee proposed by the Tubridgi Parties. On this basis, the Regulator considers that an application fee for a transmission service is not a common practice in the gas transmission industry.

Notwithstanding that an application fee is not common practice, the Regulator notes that the size of the fee proposed by the Tubridgi Parties is small and could readily be justified by administrative costs of processing an application. Furthermore, no objections to the fee were made in public submissions. On this basis, the Regulator is of the opinion that the proposed application fee is not unreasonable or unduly inconsistent with the interests of Users.

6.4 OVERRUN CHARGE

6.4.1 Access Arrangement Proposal

Clause 4.2 of the General Terms and Conditions provides for the Tubridgi Parties to charge an overrun charge on any day that a User's peak daily quantity exceeds that User's maximum daily quantity. The overrun charge is to be calculated as the excess of the peak daily quantity over the maximum daily quantity, multiplied by an overrun rate. The overrun rate is specified in the Access Arrangement to be $0.15/GJ, equivalent to 143 percent of the proposed throughput tariff ($0.105/GJ).

In addition to the overrun charge, whenever the quantity of gas delivered on any pipeline day through a User delivery point on behalf of the User exceeds the MDQ for that User delivery point, the MDQ for that User delivery point will be increased to be equal to the quantity of gas delivered on that day (clause 4.4 of the General Terms and Conditions). As the User would henceforth pay a correspondingly higher amount in MDQ charges, this also imposes a penalty for overruns. It is noted, however, that the Regulator will require that this provision be removed from the Access Arrangement (Amendment 7).

6.4.2 Submissions from Interested Parties

None of the submissions made in respect of the Access Arrangement addressed the matter of the overrun charge.

6.4.3 Other Considerations of the Regulator

In assessing whether the proposed overrun charge is a reasonable practice on the part of the Tubridgi Parties, the Regulator considered the practice of other Service Providers in respect of similar charges.

A summary of provisions for overrun charges proposed or in place for other transmission pipelines is summarised as follows from Access Arrangement documentation.

Quantity Variation Charges of Gas Transportation Service Providers

Service Provider and Pipeline	Provision for Quantity Variation Charges	Quantity Variation Charge
AGL Pipelines (NSW) Pty Limited Central West Pipeline[56]	Daily Variance Charge A daily variance charge may be levied on a User if there is a daily variance of more than 10 percent of the Delivery Point MDQ or Receipt Point MDQ for more than 4 days in a month or 24 days in a contract year.	Daily variance rate not specified in the Access Arrangement.
N.T. Gas Pty Limited Amadeus Basin to Darwin Pipeline[57]	Daily Variance Charge A daily variance charge may be levied on a User if there is a daily variance of more than 10 percent of the Delivery Point MDQ or Receipt Point MDQ for more than 4 days in a month or 24 days in a contract year.	120 percent of relevant service tariff.
East Australian Pipeline Limited Moomba to Sydney Pipeline[58]	Daily Overrun Charge If a User exceeds its MDQ, or the quantity of gas accepted by EAPL as an authorised overrun is exceeded, then the excess quantity of gas will be treated as an unauthorised overrun for which the User will be required to pay an "unauthorised overrun charge". If because of a User's unauthorised overrun EAPL is unable to comply with obligations to transport Gas for other Users, then the User will be liable for any loss, cost or damage EAPL may incur, including consequential loss.	350 percent of relevant capacity tariff and 100 percent of relevant throughput tariff for unauthorised overrun.

The overrun charge proposed by the Tubridgi Parties is generally consistent with charges proposed to be levied under two other Arrangements. On this basis, and in view of the absence of public submission on the matter of overrun charges, the Regulator is of the opinion that the proposed overrun charge is not unreasonable. It is noted, however, that the Tubridgi Parties may wish to revise provisions in the Access Arrangement relating to overrun charges in light of the Regulator required amendment (Amendment 7) to remove provision from the Access Arrangement for automatic increases in a User's MDQ subsequent to any overrun.

6.5 GOODS AND SERVICE TAX

Clause 16 of the General Terms and Conditions provides for a User to be liable to pay the Tubridgi Parties for any goods and services tax (as is to be implemented under the *A New Tax System (Goods and Services Tax) Act* (Cth) *1999*) payable in respect of a service provided to that User. The liability for goods and service tax is to be calculated by multiplying (i) the amount that would otherwise be payable under the relevant service agreement if the goods and services tax payable were nil, by (ii) the prevailing rate of the goods and service tax.

[56] Access Arrangement submitted to the ACCC 31 December 1998.

[57] Access Arrangement submitted to the ACCC 25 June 1999.

[58] Access Arrangement submitted to the ACCC 5 May 1999.

6.5.1 Submissions from Interested Parties

No submissions were made on the matter of liability for payment of the goods and services tax.

6.5.2 Additional Considerations of the Regulator

The Tubridgi Parties propose that the goods and services tax will be passed through to Users by increasing charges by a factor of one plus the rate of the goods and services tax.

The Regulator is of the view that the Code does not provide for changes to Reference Tariffs other than by a review of the Access Arrangement, or in accordance with provisions for change that may be included in the Reference Tariff Policy under section 8.3 of the Code. The Code does not appear to accommodate a change in the tariff to pass through a taxation impost such as the goods and services tax. Consequently, the Regulator will require the Access Arrangement to be amended to remove the provision for pass through of the goods and services tax to the Reference Tariff. Notwithstanding this, the Regulator has taken into account the additional cost incurred by the Tubridgi Parties as a result of the goods and service tax in a revision to the proposed Reference Tariff (section 5.9.4 of this Draft Decision), and hence the provision for pass through of the tax impost is redundant.

The following amendments are required before the Access Arrangement will be approved.

Amendment 44

Clause 16 of the General Terms and Conditions should be amended to remove the provision for a User to be charged an amount in excess of the Reference Tariff for the purposes of recovering any goods and service tax liability incurred by the Tubridgi Parties as a result of the Reference Service being a taxable supply within the meaning of the *A New Tax System (Goods and Service Tax) Act 1999*.

6.6 TAXES AND IMPOSTS

6.6.1 Access Arrangement Proposal

Clause 17 of the General Terms and Conditions provides for the Tubridgi Parties to recover from Users the costs incurred by the Tubridgi Parties as a result of any impost imposed on or paid or payable by the Tubridgi Parties in relation to the provision of pipeline services. An impost is defined in the Access Arrangement as:

> any royalty, duty, excise, tax, impost, levy, fee or charge (other than any GST as defined in the *A New Tax System (Goods and Services Tax) Act 1999*) imposed now or in the future by the Commonwealth of Australia or any State or Territory of Australia on or in respect of the Tubridgi Pipeline System (or any part of it) or on or in respect of the operation, repair, maintenance, administration or management of the Tubridgi Pipeline System (or any part of it) or on or in respect of any Pipeline Service.

In addition, clause 17.2 of the General Terms and Conditions provides the Tubridgi Parties with discretion to determine the basis for apportionment between Users of any impost on, or paid or payable by, the Tubridgi Parties that is not directly related to the services provided to any User.

The provision for Users to bear and pay all imposts effectively provides for the Tubridgi Parties to pass through to Users any increase in costs arising from government taxes and charges as described in the definition of an impost.

6.6.2 Submissions from Interested Parties

No submissions were made on the matter of charges being levied on Users to recover costs incurred by the Tubridgi Parties through taxes and imposts.

6.6.3 Additional Considerations of the Regulator

As indicated above in relation to the goods and service tax, the Regulator is of the view that the Code does not provide for changes to Reference Tariffs other than by a review of the Access Arrangement, or in accordance with provisions for change that may be included in the Reference Tariff Policy under section 8.3 of the Code. The Code does not appear to accommodate a change in the tariff to pass through to the Reference Tariff a taxation or other impost as contemplated by clause 17 of the General Terms and Conditions, without a review of the Access Arrangement in accordance with provisions of section 2 of the Code. Consequently, the Regulator will require the Access Arrangement to be amended to remove the provision for the Tubridgi Parties to recover from Users the costs incurred by the Tubridgi Parties as a result of any impost imposed on or paid or payable by the Tubridgi Parties in relation to the provision of pipeline services.

The following amendment is required before the Access Arrangement will be approved.

Amendment 45

Clause 17 of the General Terms and Conditions should be amended to remove the provision for the Tubridgi Parties to levy charges on Users, in addition to the Reference Tariff, to recover any impost imposed on or paid or payable by the Tubridgi Parties in relation to the provision of pipeline services.

6.7 COSTS OF ENTERING INTO A SERVICE AGREEMENT

6.7.1 Access Arrangement Proposal

Clause 34 of the General Terms and Conditions requires that a User must bear its own costs, and the costs of the Tubridgi Parties, in connection with the preparation, negotiation, execution and delivery of a service agreement, and all stamp duty payable in respect of the agreement or any document prepared or executed pursuant to the agreement.

6.7.2 Submissions from Interested Parties

- AlintaGas Trading

  Clause 34 of the General Terms and Conditions proposes that the User should pay its own costs and those of the Tubridgi Parties in preparing, negotiating, executing and delivering an Agreement. This might be acceptable for those costs that are not be recovered elsewhere. However, it would appear from page 13 of the Access Arrangement Information that the Tubridgi Parties' pipeline marketing costs, including the costs of attending to the commercial arrangements associated with the Tubridgi Pipeline, are to be recovered as part of the Non-Capital Costs of the Tubridgi Pipeline.

The Regulator concurs with the view expressed in this submission that the Access Arrangement appears to provide for the Tubridgi Parties to recover some costs of preparing, negotiating, executing and delivering a service agreement both through the tariffs (as a component of Non-Capital Costs) and through additional charges to the User. In addition, the Regulator notes that practice under two current Access Arrangements for transmission pipelines in Australia is for each party to a service agreement to bear its own costs in connection with preparation, execution and delivery of the agreement, and for the User to pay all stamp duty payable on or in respect of the agreement.[59]

The Regulator is therefore of the opinion that it is not reasonable for the Access Arrangement to seek to recover costs through charges that are in addition to the tariffs and charges specified in the Access Arrangement, except where the additional charges are both readily predictable by a Prospective User and readily distinguished from other costs that may be recovered by the Service Provider through other means.

The following amendment is required before the Access Arrangement will be approved.

> Amendment 46
>
> Clause 34 of the General Terms and Conditions should be amended such that the imposition of charges on a User for the preparation, negotiation, execution and delivery of a service agreement is limited to the costs of stamp duty and other government imposts.

6.7.3 Additional Considerations of the Regulator

The Regulator has no concerns with the provisions of Clause 34 other than addressed in relation to public submissions.

6.8 CHARGES FOR CAPACITY TRANSFERS AND CHANGES OF RECEIPT POINTS AND DELIVERY POINTS

6.8.1 Access Arrangement Proposal

Clause 6.4 of the Access Arrangement provides for the Tubridgi Parties to charge Users for:

[59] Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy South Australia Pty Ltd, 31 March 1999), Access Arrangement for the Mildura Pipeline (Envestra, 11 November 1999).

- a fee of $150 payable on application for a transfer of capacity, other than a Bare Transfer, or on application for a change of Delivery Points or Receipt Points; and
- reimbursement of the Tubridgi Parties for costs incurred in assessing the technical and commercial feasibility of an application for a transfer of capacity, other than a Bare Transfer, or an application for a change of Delivery Points or Receipt Points, with costs agreed in advance with the party making the request and based on an hourly rate of $150/hour for each hour after the first hour.

6.8.2 Submissions from Interested Parties

No submissions were made on the matter of charges for trading of capacity or changes in receipt and delivery points.

6.8.3 Additional Considerations of the Regulator

The Regulator is of the opinion that the proposed fee of $150 to accompany a request for a transfer of capacity or a change in receipt points or delivery points is immaterial and not contrary to the interests of Users.

The reimbursement to a Service Provider of costs of assessing the technical and commercial feasibility of a request for transfer of capacity or a change in receipt points or delivery points is not explicitly provided for by the Code. However, the Code does provide for a Service Provider to obtain reimbursement of costs associated with assessing the technical and commercial feasibility of a request for a service. The reimbursement of costs of assessing the technical and commercial feasibility of a request for transfer of capacity or a change in receipt points or delivery points is consistent with this precedent established by the Code. As such, the Regulator is of the opinion that the recovery of costs from Users is reasonable.