

GGT



G O L D F I E L D S

G A S

T R A N S M I S S I O N

**GOLDFIELDS GAS PIPELINE
REVOCATION APPLICATION**

**Submitted to the
National Competition Council**

26 March 2003

Application for Revocation of Coverage of Pipeline National Gas Access Code Goldfields Gas Pipeline System

Table of Contents

<i>Table of Contents</i>	1
(A) APPLICANT’S NAME AND CONTACT DETAILS	3
(B) APPLICANT’S ADDRESS FOR THE DELIVERY OF DOCUMENTS.....	3
(C) DESCRIPTION OF THE PIPELINE.....	3
(D) NAME OF THE PIPELINE OPERATOR AND OWNER.....	4
(E) WHETHER THE APPLICANT IS SEEKING REVOCATION OF COVERAGE OF ALL OR PART OF THE PIPELINE	4
(F) REASON FOR SEEKING REVOCATION OF COVERAGE OF THE PIPELINE.....	5
BACKGROUND	5
CURRENT SITUATION UNDER THE NATIONAL CODE	9
IMPACT OF COVERAGE ON THE GGP	14
(G) GROUNDS FOR REVOCATION.	17
CRITERION (A):	20
DESCRIPTION OF RELEVANT MARKETS	20
(1) <i>The upstream market:</i>	22
(2) <i>The downstream market;</i>	23
(3) <i>The transmission market:</i>	27
GROUNDS FOR REVOCATION UNDER CRITERION (A).....	29
(i) <i>That open and non-discriminatory third party access already exists.</i>	29
(ii) <i>That sufficient incentive to promote the use of the pipeline already exists.</i>	30
(iii) <i>GGP is not able to significantly influence the market within the relevant markets.</i>	32
(iv) <i>Coverage will not promote the conditions for any increased competition in any other market.</i>	42
CRITERION (B):	60
DESCRIPTION OF SERVICE PROVIDED BY GGP	60
GROUNDS FOR REVOCATION UNDER CRITERION (B)	62
(i) <i>Past and continuing history of competitive development.</i>	63
(ii) <i>Currently economic to develop another pipeline to provide the services provided by means of the GGP.</i>	64
(iii) <i>Pipeline infrastructure development has already realised social benefits with continuing potential for future benefits.</i>	71
(iv) <i>The GGP does not enjoy unconstrained monopoly power or barriers to entry.</i>	74
CRITERION (C):	78
CRITERION (D):	79
(i) <i>Benefits of competition already exist.</i>	79
(ii) <i>Increased regulatory costs and investment disincentives reduce asset life and the ability to compete or expand.</i>	80
(iii) <i>Coverage imperfectly substitutes and distorts already effective market forces.</i>	84

ATTACHMENTS /

ATTACHMENT 1 : RELEVANT CHRONOLOGY

- ATTACHMENT 2 : COMPARISON OF THIRD PARTY ACCESS – CURRENT AND PROPOSED
- ATTACHMENT 3 : GAS RESERVES IN WESTERN AUSTRALIA
- ATTACHMENT 4 : DETAILED SUMMARY OF DOWNSTREAM MARKET ANALYSIS
- ATTACHMENT 5 : GAS QUALITY SPECIFICATION
- ATTACHMENT 6 : OVERVIEW OF ECONOMIC DEVELOPMENT TARIFF (EDT)

APPENDICES :

- APPENDIX 1 : LOCATION MAPS
- APPENDIX 2 : GOLDFIELDS GAS PIPELINE: RELEVANT DOWNSTREAM MARKETS, VENTNOR CONSULTING GROUP, MARCH 2003.
- APPENDIX 3 : COMPARISON OF STATE AGREEMENT AND CODE AGAINST THE CRITERIA OF THE COMPETITION PRINCIPLES AGREEMENT.
- APPENDIX 4 : GGT SUBMISSION TO THE PRODUCTIVITY COMMISSION REVIEW OF THE NATIONAL ACCESS REGIME, 2001.
- APPENDIX 5 : ARTICLE: SEARCH FOR NEW CUSTOMERS, PROSPECT, DRD, DEC'95/FEB'96
- APPENDIX 6 : THE DEVELOPMENT OF GORGON AREA GAS.
- APPENDIX 7 : GOVERNMENT MEDIA STATEMENTS.

GLOSSARY 87

END NOTES 88

Note on referencing in this document:

footnotes: are used for comments and to provide reference where the cited text is included in the body of the application.

endnotes: are used where it has been relevant to reference excerpts or passages of text or statements, which are for convenience more fully expanded at the end of the document.

(A) APPLICANT'S NAME AND CONTACT DETAILS

Goldfields Gas Transmission Pty Ltd (GGT)
(ACN 004 273 241, ABN 87 004 273 241)

Contact details for GGT are as follows:

Mr David King
General Manager
Goldfields Gas Transmission Pty Ltd
Level 8 Australia Place
15-17 William Street, Perth
Western Australia 6000

Phone: (08) 9320 5601
Fax: (08) 9226 4126

(B) APPLICANT'S ADDRESS FOR THE DELIVERY OF DOCUMENTS

Mailing address:

Goldfields Gas Transmission Pty Ltd
Level 8 Australia Place
15-17 William Street, Perth
Western Australia 6000

email: daking@ggt.com.au

(C) DESCRIPTION OF THE PIPELINE

The Pipeline is described in Schedule A of the Code as follows:

Pipeline Licence	Location/Route	Operator	Length (km)	Pipe diameter (mm)	Regulator
WA:PL24	Goldfields Gas Pipeline System Goldfields Gas Pipeline GGT Newman Lateral	GGT*	1,380 47	400, 350 219	A WA Independent Regulator

* Agility Services (previously AGL) has been approved to operate the pipeline on behalf of GGT

(D) NAME OF THE PIPELINE OPERATOR AND OWNER

The pipeline is owned by an unincorporated joint venture comprising:

- Southern Cross Pipelinesⁱ Australia Pty Limited, ACN 084 521 997, whose individual share is 62.664%;
- Southern Cross Pipelines (NPL) Australia Pty Ltd, ACN 085 991 948, whose individual share is 25.493%; and
- Duke Energy WA Power Pty Ltd, ACN 058 070 689, whose individual share is 11.843%

(collectively "the **Owners**").

The pipeline is operated by GGT for and on behalf of each of the Owners and GGT is the Service Provider under the Code.

(E) WHETHER THE APPLICANT IS SEEKING REVOCATION OF COVERAGE OF ALL OR PART OF THE PIPELINE

GGT is seeking revocation of coverage of the entire GGP pipeline, Newman lateral and any further extensions or expansions as might be described under sections 1.40 and 1.41 of the Code.

It should be noted that GGT is not seeking to avoid or in any way diminish the third party access obligations that exist under the State Agreement regulatory regime which pre-existed the Code, and which continues to have contractual force. Further, it should be noted that the GGP will remain subject to this pre-existing contractual Agreement whether or not this application for revocation of coverage under the Code is successful. In the event that this application for revocation is not successful, certain aspects of the specific interaction of the former ratified contractual Agreement and current regulatory regime are likely to remain the subject of ongoing legal interpretation.

The current GGT gas transportation tariffs and pricing principles, as well as the standard terms and conditions for access which form the basis for third party access negotiations, are published on the GGT website at www.ggt.com.au.

ⁱ Although the ownership of the GGP has changed over time, the current beneficial ownership of the Southern Cross Pipelines group is, CMS (45%), APT (45%) and Transalta (10%). It should be noted however that at the time of lodging this application, APT is in the process of acquiring the interest currently held by Transalta.

(F) REASON FOR SEEKING REVOCATION OF COVERAGE OF THE PIPELINE

BACKGROUND

The following background information is intended to provide a relevant context for the subsequent consideration of each of the coverage criteria, which are individually addressed in later sections of this application.

The GGP was funded, built and owned by a private consortium in 1995-96. The location of the pipeline and its major physical components (compressor stations, offtakes, etc) are illustrated in Map 1 of Appendix 1.

Prior to the development of the GGP, electrical power had been supplied to the Kalgoorlie and Kambalda areas by the State Energy Commission of Western Australia ("SECWA", now Western Power Corporation), while remote sites such as Mount Keith and Leinster were supplied by local, company owned, diesel power stations.

The Western Australian Government had for some time had its own broad objectives for wishing to see the development of a gas pipeline to the Goldfields. According to the then Minister for Resources Development and Energy¹ the pipeline offered major benefits to the State in terms of a competitive, more reliable energy supply which would promote competition in downstream and upstream markets, increasing royalties to the State and improving the national balance of payments.

There was general bipartisan political support within the State Government for the provision of infrastructure to deliver energy to mines in order to facilitate downstream processing and value adding industry.²

Furthermore, the economic significance of the reliance upon diesel fuel was noted for its detrimental impact. One politician at the time described the situation thus:

"Something like one million litres of fuel oil and/or diesel goes into the goldfields on a daily basis at a cost of about 80c a litre. It is not hard arithmetic to work out that on a daily basis about \$800 000 of fuel oil and/or diesel goes to the goldfields regions. That costs Australia dearly because a significant part of that, on average about one-third, is imported annually. That is, about one-third of the \$800 000 to \$900 000 - say, \$250 000 to \$300 000 - flows overseas daily."ⁱⁱ

However the State Government had previously been unable to justify the infrastructure investment necessary to remedy this situation. According to the State Minister, SECWA had concluded that the building of a gas pipeline to bring gas from the north west of the state down to the Goldfields was not viable.³ The Australian Bureau of Agricultural and Resource Economics had confirmed that view, noting that insufficient demand existed to underwrite the investment.⁴

ⁱⁱ Hon P.R. Lightfoot, Hansard, 12 April 1994, page 11890, Second Reading.

Despite this adverse view by the government economists, there was certainly some demand for a gas pipeline from within the private sector. For the mining companies located in the Pilbara and Goldfields regions, particularly those companies that also owned a share of the substantial offshore gas fields located in the Carnarvon Basin, continued reliance on expensive electricity and diesel was economically inefficient. In the Kalgoorlie area, electricity supplied from the South West Interconnected (electricity transmission) System ("SWIS") was predominantly produced in large scale but distant coal-fired power stations and involved high transmission costs. For other remote power consumers, the linkage between the price of diesel fuel and the international oil price meant that consumers were exposed to world oil price "spikes".

According to one of the main GGP project initiators, the project objectives which underpinned the eventual development of the pipeline were:

- *"To provide enduring low cost energy,*
- *End risk exposure to crude oil price spikes,*
- *Environmentally "clean" fuel,*
- *Development of East Spar gas field (WMC 30% owner and Operator)."*ⁱⁱⁱ

During 1992, a number of companies independently undertook studies investigating the feasibility of constructing a natural gas pipeline to supply the Goldfields region of Western Australia. A number of pipeline options were considered, including links from the Dampier to Bunbury Natural Gas Pipeline ("the DBNGP"), to supply gas from fields in the Carnarvon Basin to mining and related operations in the Goldfields.

WMC, Normandy and BHP formed a Joint Venture ("the GGTJV") to pursue the project. A description of what projects existed and where they are located can be found in Appendix 2 (Goldfields Gas Pipeline: Relevant Downstream Markets, Ventnor Consulting Group, July 2002). The location and geographical distribution of the pipeline's customers is shown in Map 2 of Appendix 1 (which also shows subsequent third party customers).

Given the spread of each Joint Venturer's interests along the pipeline route, the percentage interests in the GGTJV were determined on the basis of volume of gas to be transported and distance to be covered.

The final composition of the Joint Venture, based on load forecasts of the time, was:

WMC	62.664 percent
Normandy	25.493 percent
BHP	11.843 percent

In April 1993, the Western Australian State Government separately called for expressions of interest for the construction of a natural gas pipeline from the Pilbara to the Goldfields.

ⁱⁱⁱ Presentation : WMC's Involvement in the Goldfields Gas Pipeline, John Harvey, Manager Energy Supply, WMC Resources, 12 March 2002.

The Western Australian State Government received expressions of interest from numerous parties regarding the development of the new pipeline, with 16 formal submissions from national, international and local companies being received.⁵

Following a competitive selection process and assessment which took into account factors including proposed access arrangements and tariff levels, the GGTJV was selected as the preferred proponent of the new pipeline, which would integrate the GGP as a transmission system with the demand of the market.⁶

The State Government and the GGTJV Participants subsequently negotiated the State Agreement, which was signed in March 1994. The agreement provided for private sector development of major infrastructure under commercial terms with light handed regulation while ensuring non-discriminatory access and tariffs and requiring the Joint Venturers to pursue market growth and to provide for further development of the pipeline capacity to serve that growth.⁷

GGT was appointed to act as pipeline manager on behalf of the Joint Venture in May 1993. A tender for the provision of pipeline operations and maintenance services was called and a contract subsequently awarded to AGL Pipelines (WA) Pty. Ltd.^{iv}

The State Agreement imposed a number of obligations on the GGTJV, including:

- field and office studies related to pipeline construction and operations;
- the gaining of pipeline route approval;
- development of third party access arrangements and tariffs in compliance with agreed principles;
- active encouragement of third party transport customers;
- provision of 50% spare capacity; and
- funding of capacity expansion.

The government involved a number of agencies in the negotiations and applied considerable expertise in relation to issues concerning third-party access to the pipeline and the pricing principles which would apply.⁸ It is highly relevant to any subsequent consideration of the tariff setting principles and the consequent pricing outcomes which have and continue to apply to the GGP, that it be noted that these were developed by the original owner-users of the pipeline. Furthermore these parties were, at the time of developing the future tariff path, fully cognisant of the fact that even in the event of their divestment of their respective interests in the pipeline asset, they would continue to represent the bulk of the pipeline's customer base.

The GGTJV was granted a pipeline licence (WA: PL 24) on 27 January 1995 to design, construct, and operate a pipeline of approximately 1380 kilometres in length to transport natural gas from DBNGP Compressor Station One at Yarraloola to Kalgoorlie, via the East Pilbara and North East Goldfields regions of Western Australia.

^{iv} AGL Pipelines became Agility Services in 2000.

Construction progressed rapidly, with particular attention being paid to the minimisation of impact on the environment during construction and the environmental restoration of the pipeline route following construction.

Commissioning of the pipeline was done progressively, from north to south. Gas was first delivered to Newman in June 1996, Mount Keith and Leinster in August 1996, and Kalgoorlie and Kambalda in September 1996. The pipeline was officially opened by the Premier, the Hon. Richard Court, on 4 October 1996.

The GGP introduced natural gas into regions where it had previously been unavailable. In introducing an alternative and competitive energy source into the markets it could reach, the pipeline displaced 140 MW of electrical generation capacity from the SWIS^v, as well as almost 300 million litres per annum of diesel fuel previously used in remote power generation.^{vi}

From the outset, the GGTJV sought to promote third party access (as well as attempt to broaden the commercial basis upon which the investment in the GGP would be made). In 1994, prior to finalising the design and capacity requirements of the pipeline, GGT offered an 'open season' for foundation third party pipeline users. This open season provided for a discount of 7.5 percent on transport tariffs for a period of five years.

However at the time, no third party took advantage of this initial incentive to use the GGP.

It was not until 1997 that four third party users took capacity on the GGP. These were Plutonic Operations (at Plutonic), Wiluna Gold (at Wiluna), AWI for Great Central Mines (at Jundee), and AlintaGas (for the distribution system in Kalgoorlie). These were followed in 1998 by Anaconda Operations (at Murrin Murrin), and AWI for Centaur Mining (at Cawse).

These subsequent third party loads, combined with the GGTJV loads, lifted the utilisation of GGP capacity to its present level.

In March 1998, consistent with the JV's obligation (and commercial interest) to promote market growth and demand, tariffs on the GGP were voluntarily discounted to approximately 85 percent of their original value.

In December 1998, WMC completed the sale of its share in the GGP to Southern Cross Pipelines Australia Pty. Ltd (62.664%). In January 1999, Pilbara Energy (i.e. BHP) sold its interest in the GGP to Duke Energy International (11.843%). In March 1999, Normandy Pipelines sold its interest in the GGP to Southern Cross Pipelines (NPL) Australia Pty. Ltd (25.493%). Following these transactions, ownership of the

^v Electricity Demand Forecasts 1996-2005, Western Power, December 1995.

^{vi} Goldfields Gas Pipeline: Relevant Downstream Markets, Ventnor Consulting Group March 2003, page 26.

Southern Cross companies comprised CMS (45 percent), AGL^{vii} (45 percent), and TransAlta (10 percent)^{viii}.

In July 1999, a further voluntary tariff discount saw the published third party transport prices fall to approximately 80 percent of their original value. In January 2000, tariffs were further discounted to approximately 75 percent of their original value.

GGT Pty. Ltd. remains as pipeline manager under the new ownership. CMS is the commercial services provider to GGT, and Agility Services (formerly AGL) remains as the contracted pipeline operator. These services are provided on a commercial basis under formal contracts.

Attachment 1 provides a table giving a concise chronological overview of the facts relevant to the development of the GGP.

The maps included in Appendix 1 show the geographical location of the GGP as well as its position relative to the markets that it serves and those in which it competes.

The current standard terms and conditions, as well as tariffs for third party access to the GGP are published on the GGT website at www.ggt.com.au.

CURRENT SITUATION UNDER THE NATIONAL CODE

The Gas Pipelines Access (Western Australia) Act 1998 ("the Act") gave effect to the national Code in Western Australia. A proposed Access Arrangement for the GGP was formally submitted by GGT on the 15 December 1999. The Western Australian Independent Gas Pipelines Access Regulator ("the Regulator") issued a Draft Decision requiring forty-nine amendments to the proposed Access Arrangement on the 10 April 2001.

On the 6 November 2002 and subsequent to the decision of the Supreme Court of Western Australia in regard to the DBNGP Draft Decision,^{ix} the Regulator issued a notice indicating his intention to revise the Access Arrangement approval process and to amend his Draft Decision issued on the 10 April 2001 with respect to the GGP. The Regulator's proposal to re-issue the GGP Draft Decision, effectively recommencing the approvals process, is partly a result of the Court's finding of certain errors of law made by the Regulator in the DBNGP Draft Decision, and a recognition by the Regulator of the commonality of certain principles that also pertain to the GGP Draft Decision.

The Regulator has now proposed a three stage process prior to the release of a Final Decision in regard to the GGP which will include recognition and application of sub-section 97(4) of the Act and clause 21(3) of the State Agreement. The Regulator

^{vii} Now Australian Pipeline Trust (APT)

^{viii} Subsequently, in February 2003, APT announced its acquisition of Transalta's 10% interest in the Southern Cross companies.

^{ix} Dr Ken Michael AM; Ex Parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, Supreme Court of Western Australia, 23 August 2002.

has stated his intention to then provide an assessment of the extent to which the Code applies to the GGP.^x

It is relevant to consideration of this application to note that under the Western Australian implementation of the national Code, the Service Provider is required to pay for the full recovery of costs associated with the maintenance and activities of the Regulator and the Office of Gas Access Regulation ("OffGAR"). The costs incurred by this government authority are apportioned in full, and directly charged back to the Service Provider and thus, coverage under the Code imposes a considerable and unavoidable cost burden in addition to the Service Provider's own costs of regulatory compliance. This cost burden is substantially compounded by the Regulator's stated reliance on litigation to resolve matters of legislative interpretation,⁹ and the effect in terms of delays and physical rework consequent to judicial outcomes.

The GGP was included in Schedule A of the Code, which includes a list of all pipelines and distribution networks deemed to be covered by the Code on the basis that they were "agreed jointly by governments as passing the coverage tests".^{xi}

Nonetheless it has become apparent that, in Western Australia at least, no rigorous assessment was ever undertaken of whether any particular pipeline, including the GGP, did in fact meet the prerequisite conditions demanding coverage and hence warranted inclusion on that original list. This was unfortunate because, as the Australian Competition Tribunal ("the Tribunal") has emphasised,^{xii} the tests for coverage require that the criteria be affirmatively satisfied. In other words, the onus is one of proof that the application of the Code contributes some positive benefit in respect of the specified criteria, relative to the circumstances that already existed. However regulatory authorities have now acknowledged that this situation can be legitimately reviewed. To cite a recent information paper jointly released by the Australian Competition and Consumer Commission ("the ACCC") and the NCC:

"Although a pipeline may be initially regulated, interested parties have the opportunity to submit an application to the NCC to assess whether regulation should continue. Section 1.9 of the code sets out the four criteria that form the basis of this assessment."^{xiii}

GGT contends that in the circumstances that existed at the time the Code was enacted, and certainly in the circumstances which currently exist, the GGP would not and does not warrant coverage under the Code.

Moreover, the State Agreement continues to apply. Whilst the GGP is a covered pipeline listed in schedule A of the Code, which means that the GGP is currently subject to the provisions of the Code, the precise manner in which the Code applies to the GGP is also affected by clause 21(3) of the State Agreement. This clause provides that the Code shall not apply to the GGP to the extent that the joint

^x Notice: Proposed Access Arrangement for the Goldfields Gas Pipeline, Ken Michael, Acting Gas Access Regulator, Office of Gas Access Regulation, 6 November 2002.

^{xi} National Third Party Access Code for Natural Gas Pipeline Systems, Schedule A.

^{xii} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, paragraph 46, page 12.

^{xiii} Regional development of natural gas transmission pipelines: A guide for regional areas considering alternatives for progressing the supply of natural gas, ACCC & NCC, October 2002, page 1.

venturers can demonstrate that it has or is likely to have a material adverse effect on the legitimate business interests of the joint venturers.¹⁰

It should be noted that the benefit of this clause has been recognised and preserved pursuant to sub-section 97(4) of the Gas Pipelines Access (Western Australia) Act 1998. The provisions embodied in the Act form a part of the Western Australian Third Party Access Regime for Natural Gas Pipelines, which was evaluated by the NCC under section 44M of the TPA, following application for certification by the State Government in March 1999. The final recommendation of the NCC was that once the Western Australian Regime applied to all of the major gas pipeline infrastructure^{xiv} in the state, it should be certified as an effective access regime. Ministerial approval of the certification followed in May 2000.

Consequently the GGP can be viewed as being subject to dual regulatory regimes, with the more recent regime preserving certain provisions of the former regime. The potential to encounter such overlapping regulatory coverage by regulatory mechanisms having essentially the same objectives may not be altogether unique, as the issue has recently been raised by the ACCC in regard to the fundamental similarity between the Code and an access undertaking under Part IIIA of the TPA.¹¹

It should be noted that whilst the previous reference specifically alludes to the fact that the Code has been "certified" under the TPA as being an "effective regime", the issue of certification of the effectiveness (according to the criteria relevant to the TPA) of the GGP State Agreement does not arise. The State Agreement continues to exist as a set of legally binding contractual obligations, albeit that as a result of its ratification and specific terms, it embodies somewhat greater recourse to independent arbitration as well as State oversight than would otherwise exist under a simple commercial contract. Any assessment of its "effectiveness" according to the criteria under the TPA would only have academic historical relevance. In any event, to the extent that the Western Australian Third Party Access Regime preserves the GGP State Agreement, it has in this context, already been certified as forming part of an effective regime.

The similarity between regimes quite clearly also holds true for the GGP State Agreement as despite the State Agreement being asset-specific, whereas the Code might be described as adopting a "forward-looking portfolio approach"¹², both regulatory mechanisms have been designed with the explicit objective of facilitating third party access.

For a concise summary of the principles upon which the State Agreement was formulated, refer to Attachment 2 ("Comparison of Third Party Access – Current and Proposed") at the end of this document. These principles, along with those of the Code, are also compared against the criteria of the Competition Principles Agreement formulated by the Council of Australian Governments ("COAG") in February 1994, in Appendix 3.

^{xiv} Prior to 1 January 2000, both the GGP and DBNGP transmission pipelines, as well as the AlintaGas Distribution Network, were subject to temporary derogations from coverage under the Code to accommodate transitional arrangements.

Further evidence of the alignment of the objectives of the State Agreement with the principles for open access under the Code is provided by the fact that the State Agreement access arrangement was deemed to be an interim approved Access Arrangement under that regime.¹³ So not only is the GGP currently subject to the overlapping obligations of two enforceable access regimes (albeit that the enforceability of the older regime survives primarily in contractual form), the arrangements under the pre-existing regime have been sanctioned under the subsequent regime, compounding the inefficiency of the duplication. A further critical consideration is that a comparison of the criteria for the effectiveness of a regime in compliance with the Competition Principles Agreement (Appendix 3) indicates that no substantial improvement in compliance with those principles, if any, arises from the imposition of the Code.

In regard to the application of dual access regimes *per se*, the ACCC has recently stated its view that if a pipeline is already regulated by a pre-existing access regime, it would be unlikely that regulation under the Code would promote any further competition. In this case, the ACCC concludes that criterion (a) of the coverage test would not be met.¹⁴ This comes back to the essential point that the onus of proof in justifying coverage is the affirmative satisfaction that the relevant benefits (as defined by the criteria in section 1.9 of the Code) will be realised. This requires therefore that positive action is required in order to demonstrate that the benefits will be realised, or at least that the circumstances are created which are likely to lead to them being realised.^{xv}

The inescapable fact is that following the introduction of the Code, the GGP has had a second regulatory regime superimposed upon the third party access obligations to which it was already subject, without the applicability of the Code having ever been evaluated. Moreover, despite coverage being presumed (rather than critically determined), the State Agreement access arrangement was in fact approved as an interim Access Arrangement under the Code and (to the extent previously discussed) is preserved by, and continues to have contractual force under, that regime.

However as the ACCC has pointed out, such a duplication of regulated access obligations does nothing to promote competition.

Moreover, the effect of the introduction of the Code in Western Australia as part of the National Access Regime and the consequences of the specific preservation of certain contractual aspects of the GGP State Agreement contained within the "effective" current regime, has changed the way in which the State Agreement must be regarded. Prior to the introduction of the Code under the Act, it may have been strictly necessary for the NCC to consider whether the GGP State Agreement conformed with the Competition Principles Agreement criteria in accordance with section 44M of the TPA. This would have allowed a decision to be made as to whether the regulatory regime would have been certified as being an "effective access regime" according to the TPA. This has been considered important by regulatory authorities as failure to achieve this certification might result in an exposure to the prospect of inefficient and potentially confusing duplication of

^{xv} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, paragraph 75, page 20.

regulation if a party were to seek to have an otherwise regulated pipeline (like the GGP) "declared" for access under Part IIIA of the TPA. Accordingly, "[c]ertification ensures that a State or Territory access regime is the *only* avenue for gaining regulated access to a particular service – services covered by an effective regime cannot be declared for access under Part IIIA of the TPA".^{xvi}

However the Western Australian access regime, including as it does the preservation of the certain pre-existing contractual rights and obligations under the GGP State Agreement, has already been certified as "effective" for the purposes of the TPA. That GGT should seek to apply for revocation of coverage under the Code is entirely consistent with, and accommodated within the terms of the Code and the State's effective access regime.

In fact, the use of this mechanism of the Code in this manner is supported in the NCC's recent recommendation in regard to the certification of the Queensland Access Regime. In respect of the proposed use by the Queensland Government of "derogations" as a means of addressing situations where the State Government believes that access regulation is not warranted, the NCC has stated its counter-view that the appropriate mechanism for seeking exemption from coverage is via the revocation mechanism contained within the Code.

"To address situations where access regulation is contrary to the public interest, the [State] Regime allows parties to seek revocation of coverage of a pipeline: s.1.9 of the National Gas Code. The process requires an explicit consideration of public interest considerations. The Council considers this to be an appropriate forum to assess whether access regulation is justified in relation to particular pipelines."^{xvii}

One might argue the procedural efficiency of requiring initial coverage merely in order to correctly apply the coverage tests that would ascertain that coverage is not warranted. However if that is to be the appropriate forum for testing the merits of coverage for established pipelines, then care must be taken to avoid circular logic. It would make a complete nonsense of the process if it were to be concluded that the "public interest" was only ever served when the conditions prevail which are unique to coverage under the Code, regardless of any failure to demonstrate significant merit or at least identify benefits which outweigh the associated costs. This would be the case if it could not be demonstrated that coverage added some practical benefit over the terms of third party access which existed prior to the Code being applied to the GGP and yet despite this (or perhaps as a consequence), the "effectiveness" of the conditions for third party access which existed prior to the introduction of the Code were then brought into question.

Furthermore, the criteria for certification of an effective regulatory access regime under the TPA form no part of the coverage tests under section 1.9 of the Code. If they did so, an obvious and intolerable circularity of logic would exist which would completely negate the effect and intention of section 1.9 of the Code.

^{xvi} NCC, "WA Access Regime for Gas Pipeline Services: Recommendation on Certification to Minister for Financial Services and Regulation", February 2000, page 2.

^{xvii} NCC, "Queensland Access Regime for Gas Pipeline Services: Final Recommendation", November 2002, page 38.

Clearly, this application for revocation is made entirely within the auspices of the Code, as implemented and certified as an effective regime within Western Australia. The question of whether or not the State Agreement would have been considered to be an "effective" regime for the purposes of section 44 of the TPA, in the absence of the Code, does not arise. In the absence of the Code, GGT is undertaking to abide by the rules for third party access which prevailed under the previous regime (whatever its current legal status), reinforced by a voluntary code of conduct as discussed later in this application. The GGP State Agreement is a contract between GGT and the State, which entails certain rights and obligations on both parties, with particular regard to ensuring fair and equitable third party access to the GGP. Beyond the normal commercial arbitration provisions applicable to any valid contract, the State Agreement also provides additional third party protection in providing the prospect of State and/or ministerial intervention.

The issue at hand is a comparison of the practicality of future third party accessibility to the GGP as it would stand in the absence of the Code (as indicated by the circumstance which prevailed prior to the introduction of the Code), and the impact of coverage on the GGP. The relevant question is whether the introduction of coverage yields any practical benefits and whether any such benefits outweigh the cost of coverage. It is GGT's contention that there is no benefit to be gained from the additional cost of coverage of the GGP under the Code.

IMPACT OF COVERAGE ON THE GGP.

The GGP has operated under a commercial regulatory environment for all its life. This sets it apart from other Australian pipelines.

The GGP was constructed and is operated under the terms and conditions of the GGP State Agreement and is also a 'covered pipeline' under the Code.

The State Agreement foresaw the possible introduction of "uniform laws" (i.e. the Act) covering third party access to natural gas pipelines. Complementary recognition of the State Agreement appears in the Act.

As has been discussed in the background section of this application, the State Agreement provided both the obligations and the government sureties under which terms it was possible for private investment in this infrastructure to take place. This was needed because, whilst the State Government wished to pursue regional development in the East Pilbara and Goldfields regions, it was not prepared to underwrite the project in any way.^{xviii}

The State Government's objectives would therefore not have been realised without the GGTJV base load and the commitment of capital by the GGTJV to the construction of the pipeline. It was acknowledged that this investment decision

^{xviii} "...at all times I have made it clear it is to be a private sector project conducted on strictly commercial grounds and that no government subsidy will be provided. The role of government will be to facilitate the project." Mr C.J.Barnett, Hansard, 22 November 1994, page 7423, Question no. 621.

involved certain risks, one of the most important being the actual capital cost of constructing the pipeline.¹⁵ Hence the appropriate sizing of the pipeline was critical in order to ensure that sufficient utilisation would underwrite the development cost.

Nonetheless, in the interest of promoting future competition and being able to meet foreseeable growth in demand, under the contractual terms of the State Agreement, the GGTJV agreed to construct a pipeline which was larger in size and hence greater in cost than what was required to satisfy the needs of the individual Participant companies. This requirement is explicitly articulated in the State Agreement, which stipulates that the capacity of the Pipeline shall be able to be expanded, by using additional compression, by a minimum of 50% of the Initial Committed Capacity.¹⁶

This meant that the GGTJV faced from the outset the commercial risk associated with the uncertainty surrounding the development of an expanded third party gas transport market. Further, the GGTJV determined initial and subsequent third party tariffs on a 'levelised' basis in order to yield tariffs which remained constant over the life of the project in real (i.e. inflation adjusted) terms.

"Tariffs were set in the first place to produce the lowest possible tariff consistent with the tariff setting principles. This was because a net present value rather than a cost of service approach was used. This essentially means that the project has estimated the likely sales and costs over the full 42 years of the project and annualised the net cash flow on a discounted basis to produce an NPV of zero using an agreed discount rate. The effect of this is to shift present costs on to the future. The result is a lower tariff in the earlier years of the project compared with a cost of service approach where actual costs on an accounting basis are recovered each year from the volume of gas sent through the pipeline."^{xix}

"The tariffs that have presently been set by the GGP were judged by the State to be consistent with the tariff setting principles."^{xx}

"The test as to whether they are fair and reasonable is left for the marketplace. If a third party is unable to agree to a tariff with the GGP, a determination by the Minister under the agreement of reasonable tariffs is triggered, and that must be consistent with the tariff setting principles. The Minister's determination is arbitrable under the agreement."

The member is claiming that the tariffs are not fair and reasonable. However, the proof of the tariff is to be found in the marketplace where the GGP has signed contracts with Plutonic Resources Ltd and Wiluna Mines Ltd and is close to signing contracts with Anaconda Nickel NL, Jundee, Cawse and Alinta. This market response suggests that the tariffs are fair and reasonable and nobody has sought a determination from the Minister under the agreement."

The GGP will commence deliveries to Plutonic in early September and to Wiluna Mines in early October. Both the GGP and the Jundee and Cawse projects are building the necessary infrastructure and connections to allow both projects to be supplied with gas in late October and March respectively, and final draft contracts have been exchanged. With the announcement by Anaconda that it has project finance, a contract is expected to be concluded shortly for the delivery of gas in March 1998."^{xxi}

^{xix} Hon. N.F.Moore, leader of the Legislative Council (at the time), Hansard, 26 August 1997, page 5364.

^{xx} *ibid*, page 5363.

^{xxi} *ibid*, page 5364.

This “whole-of-life” methodology reduced tariff levels in the early years of the project with the explicit intention of promoting the use of the pipeline. This tariff levelling (ie. initial reduction in the early years of the project in exchange for sustained price levels later), results in capital recovery being deferred to later years of the project life.^{xxii} This deferment of capital recovery involves a financial cost of uncertain magnitude and duration which in itself imposes further risks upon the GGTJV associated with the sustainability and growth of the market, as well as unforeseeable changes in the regulatory and commercial environment.

In 1993, the GGTJV was one of several proponents seeking to progress the development of the GGP. The State Government used a competitive process to select the GGTJV ahead of other project proponents. Selection was based on reasoned and comprehensive criteria, which included assessment of third party tariffs.

The initial development of third party tariffs for the GGP was done under clearly defined and prescriptive tariff setting principles agreed under the State Agreement which specifically promote third party access and protect the interests of third party users. The process by which initial tariffs were developed was overseen by the Department of Resources Development (“DRD”, subsequently renamed the Department of Mineral and Petroleum Resources, “DMPR”, and now the Department of Industry and Resources, “DoIR”), whose minister approved the project proposals, including the tariffs finally promulgated.

Subsequent published third party tariff discounts have also been developed under the tariff setting principles set down in the State Agreement. Thus, the ability of third parties to equitably access the GGP under known terms of access has been (and continues to be) provided for from the time of the pipeline's inception.

It is also relevant to note that the original tariff path was developed by the pipeline's vertically integrated owner-users in full recognition that, even in the event that they might one day divest their respective interests in the pipeline asset, they would almost certainly continue to make up the bulk of the customer base for the pipeline's services. This situation has of course eventuated, and the original owner-users do in fact now comprise approximately 75% of current GGP contracted gas deliveries.^{xxiii} This provides considerable ongoing market leverage in the hands of only three customers (out of a total of only ten customers served by the pipeline).

So while the GGP as it exists today is a product of commercial and competitive forces and processes, the importance of ensuring access to the GGP by third parties was explicitly recognised at the time that the GGTJV and the State Government negotiated the State Agreement. The requirements that the GGTJV actively seek third party users and that pipeline capacity be set at time of design to accommodate the needs of third party users are fundamental to the State Agreement.

^{xxii} This approach is similar in concept and effect to the idea of “economic depreciation” advocated by the ACCC in its role of regulator under the Code. (see “Draft greenfields guideline for natural gas transmission pipelines”, ACCC, June 2002, page 2. etc.)

^{xxiii} Refer to Map 2 in Appendix 1 of this application.

Furthermore, on the issue of future capacity expansion obligations, the State Agreement and the Code differ significantly, with the Code being considerably less favourable to prospective users. Under the State Agreement, GGT is required to expand capacity in order to meet the “reasonable needs” of a third party access seeker (per clause 20) to the extent that it is “economically and technically feasible”, although GGT is not required to fund the construction of any lateral.^{xxiv}

Under the Code however, the Service Provider is required to expand capacity only to the extent that the party seeking access is prepared to fund the investment in capacity expansion. While this is not an inequitable proposition, it manifests a certain level of risk upon users if the Regulator under the Code fails to provide the correct incentives for further investment, as Epic Energy have highlighted:

“Consistent with these objectives of the Code, the Service Provider has an unfettered discretion under the Code on the issue of whether it should invest further in a covered pipeline. Sections 3.16 of the Code provides that the Service Provider can not be compelled to provide in its extensions/expansions policy that it will fund New Facilities, unless it agrees. Furthermore, section 6.22 of the Code also states that a Service Provider can not be compelled by an arbitrator in an access dispute, to fund any part of the expansion of the pipeline.”^{xxv}

Thus the Code exposes future pipeline users to the requirement to directly fund that portion of capacity expansion which is required to meet their individual needs. This has at least two negative consequences for the user. The first is the need to apply the user’s own funds up front and at the user’s own real cost of capital, which is likely to be higher (and for upstream developers it is likely to be considerably higher) than the cost of funds available to pipeline infrastructure investors. The second problem is associated with the size of any incremental capacity expansion. A user will be unable to justify any investment in capacity beyond that necessary to meet its own needs and so the economy of scale that might have otherwise been available to the pipeline operator will not be captured. This can result in significant economic inefficiencies to both the immediate user, as well as from a societal perspective in terms of future expansion.

Clearly the application of the Code has afforded no benefit in any regard to the conditions for access to the GGP. If anything the effect of the application of the Code has already had a detrimental impact in terms of regulatory uncertainty, market confusion, additional cost of supply and specific terms of capacity availability.

(G) GROUNDS FOR REVOCATION.

The GGP was included on the original list (Schedule A) of pipelines to be covered under the Code when it came into force. Although no analysis or evaluation was

^{xxiv} This is explicit recognition that the reach of pipeline infrastructure (and hence the promotion of growth and sustainable development in the market) is governed by the rules of economic viability.

^{xxv} EPIC’s response to DBNGP User’s re- 2nd class citizens argument, Additional Information DD2: Response to the Existing Shippers’ Submission on Epic Energy’s “Second Class Citizens” Claim, 5 October 2001.

undertaken as to whether the criteria for coverage were in fact satisfied with respect to the GGP, the GGT JV did not contest automatic coverage at the time on the basis that:

- (a) There was a pre-nascent desire to avoid a multiple regulatory regime environment if possible,
- (b) The option of derogation (which was raised by the State Government) would have introduced the spectre of yet another regulatory regime (in the form of an option for declaration under Part IIIA of the TPA) unless certified as being an effective regime under the TPA: an option which has been subsequently demonstrated to be procedurally problematic,
- (c) Having no philosophical opposition to being regulated in an appropriate form, it was thought that a nationally uniform set of regulations would be the simpler and more desirable outcome than maintaining multiple access regimes (providing it did not erode the existing rights of the JV), and
- (d) Based upon indications from government, it was believed at the time that the Code was being developed as a light-handed regulatory approach that would be synonymous in effect with the State Agreement.

In the actual event, the cost of coverage under the Code has been demonstrated to be significantly more than anticipated. In fact, regulatory costs under the Code are becoming increasingly onerous, with no offsetting benefits arising from the additional expense, particularly compared to the outcomes that prevailed under the pre-existing regulatory regime.

Furthermore it has become clear that with the advent of the Code in the form finally realised, the GGP will continue to be subject to the obligations of multiple regulatory regimes. As discussed previously, this arises from the effect of clause 21(3), which has been preserved in the State legislation that enabled the Code in Western Australia.

It could be noted however that the effect of clause 21(3) on the Regulator's powers and duties, and decisions made by him, under the Code was the subject of recent Supreme Court proceedings against the State and the Regulator. However, the Regulator has recently announced his intention to redress an earlier failure to acknowledge "certain jurisdictional issues associated with the interaction between section 97(4) of the GPAA and sub-clause 21(3)" of the State Agreement in a re-assessment of his GGP Draft Decision.^{xxvi} Whether or not the weight ultimately given to these matters by the Regulator or his interpretation leads to further litigation is a moot point for the purposes of this application. In any event, to the extent that any such proceedings are concerned with the practicalities of the interaction of the Code and the State Agreement, they have no bearing upon the question of applicability to the GGP of coverage under the Code or upon this application.

What is however pertinent in considering the criteria upon which the need for coverage is justified, is the question of likely outcome, an issue that would normally require some judgement. To quote the Tribunal in the Duke Eastern Gas Pipeline appeal decision ("the EGP Decision"), "*The enquiry is as to the future with coverage*

^{xxvi} Notice: Proposed Access Arrangement for the Goldfields Gas Pipeline, Ken Michael, Acting Gas Access Regulator, Office of Gas Access Regulation, 6 November 2002.

and without coverage".^{xxvii} The onus is on the affirmative demonstration that the "future with coverage" will, or is likely to lead to circumstances which will produce positive benefits (in terms of the coverage criteria), relative to the situation which exists without coverage.

In the case of the GGP, the "future without coverage" has already been shown. It is the situation which existed under the contractual obligations of the pre-existing and surviving State Agreement third party access regime.

In regard to the "future with coverage", the effects of clause 21(3) in respect to excluding the utilised portion of the original "Initial Committed Capacity" of the pipeline, as well as the exclusion of any aspect of the Code which can subsequently be demonstrated to have a material adverse effect upon the legitimate business interests of the pipeline owners, are relevant considerations. If any benefits to any party from coverage can be identified (which GGT contends is not the case), particularly if such benefits arise at the expense of GGT, then appropriate consideration would need to be given to the prospect of clause 21(3) significantly diluting the reach of such benefits. On the other hand, the funding provisions imposed by the Code would see a transfer of the full, and demonstrably substantial, regulatory compliance costs being imposed upon the market. These factors are of course relevant to any consideration of criteria (a) and (d).

The preceding section of this application (Section f) provides detail of the history and present status of the GGP in regard to third party accessibility. In the following sections of this application, each of the specific criteria upon which coverage might be justified, are addressed with respect to this contextual background.

^{xxvii} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001,, paragraph 75, page 20.

CRITERION (A):

"that access (or increased access) to services provided by means of the pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the pipeline"

DESCRIPTION OF RELEVANT MARKETS

How the relevant markets are defined, and consequently how the GGP's role and significance in those markets is described, is crucial to any assessment of the appropriateness or otherwise of Code coverage. As the former Executive Director of the NCC has put it;

"Pipelines that do not have relevant, enduring and substantial market power should not be covered by the Code".¹⁷

This view has been endorsed in conclusions drawn by the Productivity Commission in its recently released report on its review of the National Access Regime.^{xxviii}

In order to determine the relevant markets according to the criteria for coverage under the Code, a pipeline must be considered within the specific geographical and market context to which it relates. Without appropriate consideration of the nature of gas transportation within a gas supply chain, the relevance of sources of supply, and the nature of the energy market and/or gas consumption market in which it ultimately competes, erroneous conclusions can be drawn.

A gas transmission pipeline is fundamentally and simply one link in a supply chain, a supply chain that in this case ultimately competes with other forms of energy to satisfy the demand of an energy consumption market. Given the physical availability of accessible energy, this market is discerning (almost exclusively) only in terms of price and reliability, with the former criterion generally being primary. A simplified view of the transmission infrastructure that underpins the energy supply system within which the GGP operates is shown in Map 3 of Appendix 1.

The Code is in a state of relative infancy. Elsewhere in Australia to date, it has been considered sufficient for regulatory purposes to adopt the narrow view of the role of transmission pipelines as merely being concerned with the point to point carriage of gas. However as time goes by, it seems inevitable that gas and electricity markets will develop into integrated energy markets. This will probably arise from organic market growth and by simple virtue of the substitution possibilities of the commodities concerned. This integration into an energy market seems likely

^{xxviii} "Finally, the Commission considers that it is essential that criterion (a) only be met where the facility in question can exercise substantial and enduring market power." Productivity Commission, Review of the National Access Regime, Report No.17, 28 September 2001, page 182. See also Recommendation 7.1 , *ibid*, page 192.

irrespective of whether any regulatory intervention is interposed (although a growing number of commentators are concerned that possibilities exist for inappropriate regulatory incentives to distort investment decisions and slow down such development).¹⁸

Once the boundaries between gas and electricity markets become blurred, such simplistic interpretations of the market role fulfilled by gas transmission pipelines as we have seen to date, will be shown to be both inadequate and misleading. Already for GGT, these boundaries do not exist. The GGP serves a market and fulfills a role, which appears to be unique within Australia in terms of the degree to which direct competition between energy forms already takes place.

In this context, the GGP services a market that is already well integrated in respect of the significant degree to which substitute energy forms compete. In this respect, it is highly analogous with the regional market aspects considered by the Tribunal in the EGP Decision.

"Regional Markets

There are several places south of Canberra on the EGP for which the EGP will be the only source of gas. Prior to the construction of the EGP these places had to rely on electricity or other forms of energy but now have the opportunity to use natural gas. There are currently off-takes from the EGP at Cooma and Bombala in NSW and at Bairnsdale in Victoria, and if the development of the Kipper gas field proceeds it is likely that a connection will be constructed to join the EGP at Orbost in Victoria.

The EGP has created a gas sales market, and increased competition in the energy market, in places which were not previously served by a pipeline. The EGP has the potential to increase competition in the gas production market if the Kipper field proceeds. The question which the Tribunal has to address in assessing criterion (a) is whether coverage of the pipeline would promote competition to a greater extent than has already occurred with the access conditions current and proposed on the EGP."^{xxix}

Similarly, the GGP "has created a gas sales market, and increased competition in the energy market, in places which were not previously served by a pipeline". The coverage question likewise is "whether coverage of the pipeline would promote competition to a greater extent than has already occurred with the access conditions current and proposed" on the GGP.

In considering whether or not the GGP satisfies criterion (a), the availability of substitutes and indeed the substitution possibility introduced into the existing energy market by the construction of the GGP must, as a matter of intellectual rigor, be given sufficient weight of consideration. In its review of the National Access Regime, the Productivity Commission has emphasised the importance of this issue:

"The Commission reiterates that, to the extent that the existence of substitute services is not dealt with under criterion (b), it is imperative that it is assessed effectively under criterion (a).

^{xxix} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, page 37.

If this were not the case, the key question of the market power related to natural monopoly would not be properly addressed."^{xxx}

In practical terms, the markets relevant to this consideration of market power can be distinguished and defined as follows:

- (1) The upstream market, being any gas producer that is physically or potentially able to access the Western Australian gas transmission network,
- (2) The downstream market, which comprises three distinct market segments,^{xxxii}
 - (i) the southern geographical end of the GGP in the vicinity of Kalgoorlie which is serviced by reticulated electricity from the SWIS and in which region, gas is delivered via the GGP for the purpose of competing in the market for electricity (estimated to comprise approximately 40-45% of total GGP throughput),
 - (ii) the geographical region north of Kalgoorlie through which the GGP passes and competes with diesel for the remote stand-alone generation of electricity (estimated to comprise approximately 50% of GGP throughput), and
 - (iii) the provision of gas for its inherent use, being mainly as industrial process gas but also for domestic consumption (estimated to be approximately 5-10% of total GGP throughput),
- (3) The transmission market, which, given that the overwhelming characteristic of the downstream market into which the GGP delivers gas is for the generation of electricity (i.e. 90-95% of gas delivered represents "unprocessed electricity"), must be taken to be the transmission of energy within an interconnected transmission network.

Each of these market descriptions is discussed in further detail in the following sections.

(1) The upstream market:

The overall energy balance in Western Australia is illustrated in Map 4 of Appendix 1. The majority of upstream gas production in the state occurs offshore in the north-west shelf region of the Carnarvon Basin. Map 5 in Appendix 1 shows the location of the existing producing fields in this area as

^{xxx} Productivity Commission, Review of the National Access Regime, Report No.17, 28 September 2001, page 192.

^{xxxii} GGT cannot publicly disclose contractual information which is protected under commercial contract arrangements, however for the purpose of this application, percentage allocations of throughput into each market segment has been calculated based upon the publicly available information collected in the downstream market analysis undertaken by Ventnor Consulting Group (see Appendix 2).

well as many of the known prospective future fields. The following table indicates the relative magnitude and source of gas production in the state during 1999/2000.

Table 2: Gas Production in W.A. in 1999/2000^{xxxii}

Carnarvon Basin	19,297 x 10 ⁶ m ³	
Perth Basin	263 x 10 ⁶ m ³	
Bonaparte Basin	30 x 10 ⁶ m ³	
Total	19,590 x 10 ⁶ m ³	i.e. 798 PJ

A breakdown of Western Australia’s existing and future (known and potential) gas reserves is provided in Attachment 3 of this application.

It should be noted that all of the state’s existing production, and the majority of its future potential gas reserves (with the possible exception of Browse and Bonaparte Basins) can potentially access all of the existing Western Australian domestic gas transmission pipeline infrastructure. As discussed elsewhere in this application, the existing terms of access for these pipelines, means that these transmission pipelines are effectively interconnected (with the physical installation of some interconnection hardware only awaiting the appropriate commercial imperative).

Of the approximate 798 PJ of gas produced in 1999/2000, approximately 386 PJ was consumed domestically, with approximately 300 PJ of this gas being transported to its final point of consumption via the state’s transmission pipeline network. The balance of the gas consumed domestically was accounted for as fuel gas (in transportation and production processes), LNG production and what is commonly known in the industry as unaccounted for gas.^{xxxiii}

The GGP currently transports approximately 27 PJ of gas per annum. Hence, the delivery of gas from the upstream source of supply via the GGP represents approximately 9% of all gas delivered via the gas transmission network, and only 3.4% of the upstream gas production market. The conceptual flow of energy from supply to demand that is illustrated in Map 4 of Appendix 1, shows for comparative purposes, the relative role and magnitude of the contribution made by the GGP.

(2) The downstream market;

An analysis of the downstream markets was commissioned by GGT and is attached to this application as Appendix 2 (“Goldfields Gas Pipeline: Relevant

^{xxxii} Energy Western Australia 2001, Office of Energy, September 2001, page 23.

^{xxxiii} Energy Western Australia 2001, Office of Energy, September 2001, Figure 13, page 17.

Downstream Markets”). For convenience, a summary of the detailed analysis is included as Attachment 4. This study illustrates the extent of the competition faced by gas supplied via GGP and the continued market dominance of alternate energy in the forms of reticulated electricity and distributed diesel generation.

Prior to the construction of the GGP, diesel and electricity from the SWIS dominated the downstream energy market in the Goldfields, Mid-West and Pilbara areas, with some market penetration by LPG.

That electricity remains readily available is illustrated in Map 3 as well as Map 6 of Appendix 1, which shows the extent of the areas serviced by the dominant government owned electricity utility, Western Power. In the vicinity of Kalgoorlie, the GGP faces direct competition from reticulated electricity delivered via Western Power’s 220kVa transmission powerline.

Notwithstanding that electricity from the SWIS is a direct competitor in the downstream market, diesel also competes directly with gas as the energy source underlying remote stand alone power generation.

In fact, this characterisation has a fundamental influence on how the downstream market must be defined. Based on an analysis of publicly available information^{xxxiv} in regard to gas deliveries via the GGP, it would appear that approximately 90-95% of GGP delivered gas is converted to electricity in order to compete directly in this energy market.

Effectively then, the GGP forms part of an energy transmission network. The extent to which this energy network interconnects is apparent in Map 3 of Appendix 1. This map shows that gas from the offshore mid and north west, as well as electricity generated in the south, north and throughout the state, has substantial access to and in places, overlap with those regions directly serviced by the GGP.

What is not apparent from Map 3 however, is the extent of the road and rail infrastructure by which means LPG and diesel fuels are distributed throughout even the most remote areas of the state. The wide distribution of remotely located generation facilities operated by Western Power illustrated in Map 6 provides only a hint at the full extent of the competition faced by GGT from privately owned liquid-fueled power generation. In fact these fuels, in particular diesel with its higher energy concentration, have significant market specific advantages inherent to them. This is because, as downstream market studies illustrate, the nature of much of the existing and future demand growth will come from small, remote mines with uncertain, but generally short to intermediate, life spans.

^{xxxiv} GGT is unable to provide factual certainty of these estimates due to contractual confidentiality requirements and, in any event, because it does not have full knowledge of the end-use to which the gas it delivers to its customers is used. However, GGT is confident that the figures presented here are reasonably indicative.

This remote power generation market sector is characterised by the following considerations:

- small mining project lives are typically less than eight years,
- gas-fired power plants generally involve higher capital expense than a diesel-fired alternative, and are less re-deployable,
- remote site mines often require on-site diesel backup as a project requirement anyway,
- reciprocating diesel engines have certain advantages (over turbines) in enabling machines to meet instantaneous load peaks,
- a diesel-fired power facility has the advantage (over gas) in load factor management in that load fluctuations can be managed without significant incremental investment, whereas for gas-fired plant, a lateral pipeline with the capacity to meet peak load conditions requires an up-front commitment of capital,
- possible low salvage value of gas turbines relative to diesel engines, which are more easily relocated,
- ongoing availability of the diesel fuel rebate.

Given these characteristics, it is seldom possible for remote sites to justify the investment in capital intensive, and non-re-deployable transmission infrastructure like pipeline laterals when it is possible to rent re-locatable diesel storage and generators. Hence for all except the largest scale projects, truck delivered, easily stored liquid fuels represent a “fit-for-purpose” energy solution, matching the investment profile of the power source with the investment profile of the mining project being powered.

That this is an effective form of competition is borne out in the table below, which shows recent potential gas customers who have chosen, for economic reasons, not to connect to the GGP.

Table 3: Recent Projects Electing to Use Diesel Rather Than Gas

Project	Resource	Approx. Distance from GGP	Approx. Load	When
Bulong	Nickel	30 km	1.5 TJ/day	1999
Tarmoola	Gold	20 km	2.0 TJ/day	99/00
Carusoe Dam	Gold	90 km	2.0 TJ/day	2001
Sons of Gwalia	Gold	20 km	2.5 TJ/day	2000
Granny Smith	Gold	150 km	4.5 TJ/day	01/02
Sunrise Dam	Gold	150 km	3.5 TJ/day	01/02
Thunder Box	Gold	22 km	3.0 TJ/day	2002

Despite the inability of the GGP to capture the projects indicated in this table, approximately 50% of the gas delivered via the GGP is consumed by projects which are located remote from the supply of reticulated electricity (but in close proximity to the GGP). In this market, the gas delivered via the GGP competes directly with diesel in order to run electrical power generation plant.

It is clear that gas is not primarily demanded in the downstream market for its inherent chemical qualities, a conclusion supported by the evidence in Table 3. In fact, as is clearly evidenced throughout the market analysis in the downstream market study (Appendix 2), virtually the entire gas throughput of the GGP is ultimately converted into electricity for final consumption.

From the above discussion it is clear that the vast majority (some 90% to 95%) of the gas transported on the GGP is used as a fuel to generate electricity in competition with either electricity reticulated via the SWIS or remote stand alone generation fuelled by diesel. As such, it is clear that it is appropriate to characterise the downstream market as an energy market and not simply the market for gas.

For the purposes of this application therefore, the reason for the multi-part definition of the downstream market provided at the start of this section is also clear. The southern geographical extent of the market (serviced by the SWIS) demonstrates quite fundamentally different characteristics to the market serviced by the GGP in its reaches north of Kalgoorlie. In both cases however, the market is characterised by energy competition.

As has been noted however, a small portion of the gas delivered by GGP is consumed directly by users, either for domestic residential or business uses, or as an industrial process input. Table 4 of Appendix 2 (Relevant Downstream Markets, page 19) indicates that approximately 0.5TJ/d of gas is delivered by AlintaGas into the domestic (business and residential) market in Kalgoorlie. The price of delivered gas for these customers is shown in the following table, which also provides a breakdown illustrating the relevance of the gas transportation component for this segment of the market.

Table 4: Delivered Gas Price to Kalgoorlie^{xxxv}

Approximate Breakdown	Residential Customer		Business Customer	
Gas Purchase	\$ 2.30/GJ	11%	\$ 2.30/GJ	12%
Transportation	\$ 3.30/GJ	15%	\$ 3.30/GJ	17%
AlintaGas	\$15.55/GJ	74%	\$ 13.72/GJ	71%
Total ^{xxxvi}	\$21.15/GJ	100%	\$19.32/GJ	100%

GGT does not have definitive information in regard to the remaining portion of the downstream market which consumes gas for industrial processing. As indicated previously and evidenced in Appendix 2, it is estimated that it constitutes less than 10% of total delivered gas, perhaps comprising in the order of 5-10%. GGT believes that from the above discussion it is clear that

^{xxxv} Table differs from table published previously by GGT nearly two years ago and included in Appendix 4, due to revision of estimates to include more conservative estimates of cost of purchasing gas and load factor, as well as inclusion of the AlintaGas Standing Charge and annual price indexing (which results in a form of "bracket creep" in terms of relative cost breakdown over time).

^{xxxvi} Per AlintaGas price schedule as at 1 July 2002, comprising Energy Charge and Supply Charge.

the relevant downstream market with respect to criterion (a) is the market for energy.

(3) The transmission market:

As discussed in the preceding section concerned with the upstream market, of the 798 PJ of gas produced in Western Australia in 1999/2000, 300 PJ was transported to its end use destination via the state's transmission pipeline network. A further 85.8 PJ was accounted for as fuel gas (in transportation and production processes), LNG production and what is commonly known in the industry as unaccounted for gas.^{xxxvii} (The remainder of the state's gas production is exported overseas as LNG).

The location of the GGP relative to other relevant transmission infrastructure is shown in Map 3 of Appendix 1. The upstream market is also illustrated in Map 5 of Appendix 1. Together, these maps show that the majority of gas producers in Western Australia are within reach of the large capacity DBNGP, which serves as a trunkline. From this structural "backbone", it is possible for gas to be shipped to offtake points in the north, mid-west and south of the state. From these offtake points, gas may be shipped inland on smaller, built to purpose gas pipelines, or converted in large scale power stations (which can also use coal or other energy sources) for reticulation inland as electricity via high voltage transmission lines.

In this regard, it is necessary to consider the relative capacities of the pipelines relevant to this application. These are indicated in the following table.

^{xxxvii} Energy Western Australia 2001, Office of Energy, September 2001, Figure 13, page 17.

Table 5: Relevant Pipeline Capacities

GGP	Maximum capacity (i)	160 TJ/day
	Current capacity (ii)	100 TJ/day approx.
	Current contracted capacity	100 TJ/day approx.
DBNGP	Maximum capacity (i)	650 TJ/day
	Current capacity	600 TJ/day
	Current contracted capacity	593 TJ/day
MidWest (iii)	Maximum capacity (i)	50 TJ/day
	Current capacity	20 TJ/day
	Current contracted capacity	6 TJ/day
GEMM (iv) [Proposed]	Maximum capacity (i)	306 TJ/day
	Current capacity	0 TJ/day
	Current contracted capacity	0 TJ/day
<p><i>Notes:</i></p> <ul style="list-style-type: none"> <i>i. Maximum capacity refers to the maximum full haul capacity that can be achieved with full compression but without looping.</i> <i>ii. Capacity is significantly affected due to the physical distribution and magnitude of gas offtake quantities, which are spread over 860km of the 1378km length of the GGP.</i> <i>iii. Capacities for MidWest Pipeline are taken from Office of Energy and APT Prospectus.</i> <i>iv. According to details published by Anaconda Nickel Limited in a discussion paper entitled, "Kick-starting The New Millennium, Developing the Goldfields and Mid-West" (December 1999), the proposed pipeline could be operational by 2004.</i> 		

It should be noted that the gas specification for all these pipelines is very similar and certainly sufficiently close so as not to present any barrier to entry for one pipeline relative to another. A table comparing gas specifications is included as Attachment 5. It should be noted that the primary source of gas into the Mid-West and the proposed Geraldton to Mount Margaret (or "GEMM") Pipelines is via the DBNGP and hence, while they are not explicitly included in Attachment 5, the specifications in the table effectively also include these pipelines.

On an annual basis, the current actual throughput of the GGP equates to approximately 27 PJ. Hence it can be seen that as a proportion of the state's gas transmission pipeline network throughput, the GGP comprises approximately 9.0% (i.e. 27 PJ out of a total of 300 PJ).

However, as has been demonstrated, the downstream market located in the inland regions of Western Australia and which GGP serves, is mostly a resource development driven market, with the overwhelming use to which gas is put being generation of electricity.

In this sense, the interconnected and/or inter-connectable elements of transmission infrastructure effectively form an energy transmission network. Accordingly it is valid to consider that the majority of the gas shipped inland should be viewed as being merely as yet “unprocessed electricity”. Therefore, the transmission of gas is but a part of the broader energy transmission network, which exists and continues to develop in Western Australia.

Within the downstream market relevant to the GGP, the primary consumption of energy is in the form of electricity. Hence the role of the GGP as a supplier of energy for electricity generation within the state’s energy transmission network, needs to be put into perspective. This is illustrated below.

Table 6: Electricity Generation in W.A. for 1999/2000^{xxxviii}

	Total State	Western Power	Via GGP*	Other Generation
Fuel used for Generation	212.4 PJ	130.2 PJ	25.7 PJ	55.2 PJ
Energy Generated	79.2 PJ	44.4 PJ	8.7 PJ	26.1 PJ
i.e. Electricity Generated	22,000 GWh	12,300 GWh	2,400 GWh	7,300 GWh

* Simplifying assumption that GGP throughput averages 74 TJ/d and 95% of the delivered gas is used for power generation

From the preceding table, it can be seen that the GGP contributes towards approximately 11% of the state’s total electrical power generation.

GROUNDNS FOR REVOCATION UNDER CRITERION (A)

The preceding discussion provides a description of the structure and nature of the markets relevant to consideration of the merits for coverage of the GGP by the Code. However, GGT contends that for the following reasons, criterion (a) of the coverage test is not satisfied.

(i) That open and non-discriminatory third party access already exists.

Formal and effective Third Party Access to the GGP with published benchmark tariffs established on commercially fair and reasonable grounds, existed prior to the Code.^{xxxix} This is explicitly laid out in the State Agreement to which GGT remains legally bound.

The State Agreement specifically provides for rights of non-discriminatory third party access to spare and developable capacity, a basis for negotiation

^{xxxviii} Source: Energy Western Australia 2001, Office of Energy, September 2001, page 37, and GGT estimates.

^{xxxix} Refer to the GGT website (www.ggt.com.au) for information including current published tariffs and pricing principles, as well as the standard terms and conditions of access, which form the benchmark for negotiated third party access.

and pricing principles, as well as arbitration in the event of an access dispute arising.¹⁹ It should be noted however, that there have been to date no access disputes and no cases requiring arbitration under the pre-existing State Agreement regulatory regime.

Therefore, GGT contends that it is entirely redundant to further impose the access conditions of the Code on the existing, regulated and commercially effective third party access obligations to which GGT is already contractually bound.

It may be worth re-emphasising that whether or not the Code continues to apply, the GGP will continue to be subject to the contractual obligations associated with regulated third party access under the State Agreement. GGT is not contesting this.

(ii) That sufficient incentive to promote the use of the pipeline already exists.

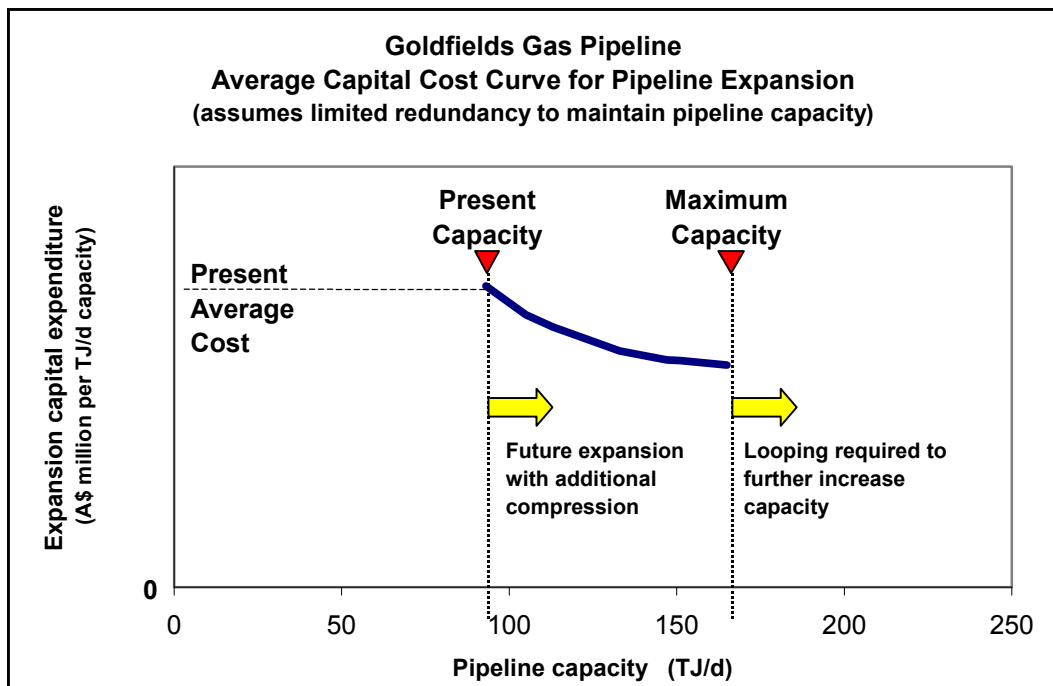
The terms of the State Agreement impose an obligation upon the owners of the GGP to promote the incremental use of the pipeline. This is made explicit in clause 19 of the State Agreement.²⁰

Further (and as previously discussed) under clause 9(5) of the State Agreement, the GGP was built with the capability of being expanded to increase capacity by 50% over its initial size. The original pipeline design involved compression located at the start of the pipeline at Yarraloola and at Ilgarari (some 600km south of Yarraloola, after the Newman offtake). Some additional compression has already been added to the pipeline (commissioned in 2001 at Wiluna) and as it is currently configured, the GGP has a capacity of 100TJ/d. With additional compression notionally located at a further six sites, this is capable of being expanded to a maximum of approximately 160TJ/d.

Thus the initial obligations of the State Agreement have served to both impose a mandatory requirement to promote the use of the pipeline, and also has created the economic incentive to do so through the availability of reduced incremental cost capacity.

Even more effectively, it is in the owners' interests to "grow" their business. This is particularly the case for gas transmission pipelines like the GGP which exhibit very high capital costs with subsequently low marginal expansion and augmentation costs leading to the situation where the cost function for capacity expansion is declining. This is illustrated in the following graph.

Figure 1.



Note: Data supporting this graph separately supplied to NCC in confidence.

Of course, it is a widely accepted economic precept that the existence of decreasing average cost in association with increasing service levels (or production) is a primary characteristic of a natural monopoly. One of the basic problems associated with the existence of a natural monopoly, which the Code is intended to address, is that the monopolist may choose to limit supply in order to maximise profit. Otherwise this results in a "market failure" in the economic sense that the service or good being supplied is not available at marginal cost as it theoretically might be in a perfectly competitive market.

However, GGT is not free to exploit this natural monopoly position. Besides the presence of competitive close substitutes for the service it provides, the GGP continues to be governed by the provisions of the State Agreement access regime. As previously mentioned, clauses 19 and 20 of the State Agreement impose very specific obligations to promote the incremental use of the pipeline.

The published third party tariffs available for the GGP have a history of discount offerings which have sought to increase the utilisation of the pipeline and hence realise the economic and social benefit of the pipeline's declining cost function. The Economic Development Tariff ("EDT") initiative which occurred just prior to GGT lodging a Proposed Access Arrangement, as it was required to do under the Code, explicitly sought to maximise the marginal cost benefit available to new users. (This is discussed in detail in Attachment 6, "Overview of Economic Development Tariff"). The lack of success of that initiative was not due in any part to a lack of desire on the part of GGT to see greater gas throughput via the GGP realised, but was more a reflection of the "economics of catchment" (see below) and of regional demand.

In any event, it can be seen that the presence of developable capacity at relatively low incremental cost, as well as an obligation upon the Service Provider under the terms of the pre-existing regulatory agreement, provide adequate incentives to promote access to the GGP.

(iii) GGP is not able to significantly influence the market within the relevant markets.

GGT contends that the GGP is not able to significantly, if at all, influence the market within the relevant markets. As previously defined, the markets of relevance to consideration of criterion (a) are:

- (1) The upstream market, being any gas producer that is physically or potentially able to access the Western Australian gas transmission network, and
- (2) The downstream market, which comprises three distinct market segments;
 - (i) the southern geographical end of the GGP in the vicinity of Kalgoorlie which is serviced by reticulated electricity from the SWIS and in which region, gas is delivered via the GGP for the purpose of competing in the market for electricity (estimated to comprise approximately 40-45% of GGP throughput),
 - (ii) the geographical region north of Kalgoorlie through which the GGP passes and competes with alternate fuels for the remote (usually "stand-alone") generation of electricity (estimated to comprise approximately 50% of GGP throughput), and
 - (iii) the provision of gas for its inherent use, being mainly as industrial process gas but also for domestic consumption (estimated to be approximately 5-10% of GGP throughput).

The influence of the GGP in each of these markets is discussed below.

The Upstream Market

As discussed in the background section of this application, the GGP at its current capacity, accounts for just 3.4% of gas produced in the upstream supply market, nearly all of which has the ability to access the gas transmission network.

In Western Australia, gas developments are driven by factors that far outweigh the role and influence of gas transportation prices. Even a cursory analysis of the Western Australian upstream gas market will reveal that, with a plethora of gas prospects awaiting the right signals for development to commence, it is a market which is demand driven. Furthermore, the critical

mass for realising this demand driven development in any significant measure, substantially exceeds the available capacity of the GGP. This is illustrated in Appendix 6, which discusses the development of the offshore Gorgon Gas field, which is cited as having 13.8 Tcf of proven gas reserves.

Such projects are driven by demand that far exceeds any possible domestic Western Australian market. Hence, the driver for investment on this scale is the LNG export market. The availability of excess domestic gas is a byproduct. In fact there may be an argument to suggest that the availability of such readily available offshore gas is, in itself, a driver to downstream development²¹ (see Appendix 6, page 2, “Gas for the State”). However this proposition, as discussed later in this application, would primarily be subject to conditions conducive to the growth in the gas transmission network. The critical issue for the promotion of significant upstream competition and substantial downstream development is the ability for new gas sources to physically reach new customers, more than it is dependant upon reductions to current gas transportation prices *per se*.

Nonetheless, upstream producers might on occasion claim that reduced gas transmission and distribution costs serve to promote upstream viability (whether or not this implies an increase in upstream or downstream competition). However, the basis for such statements needs to be understood.

For a start, it should be recognised that this view is predicated upon delivered gas prices not being significantly reduced, if at all. The premise is that the delivered price which the consumer sees will remain the same, and the upstream producer will appropriate a proportion of the gas delivery cost in order to subsidise an otherwise sub-profitable (or perhaps, just less profitable^{xi}) upstream project. In considering this, it is essential to recognise that such claims relate only to gas reserves (whether they be from new fields or incremental reserves from an existing field) which, without subsidisation, are marginal to produce.^{xii} This marginality in itself implies something about the gas volumes that are being referred to by the upstream proponent:

1. Either they are currently sub-economic increments to an existing development, or they are new potential reserves of insufficient magnitude to realise the necessary economy of scale to be economic to develop in their own right, in which case the question must be asked as to whether the development of such small resource volumes constitutes a sufficiently substantial

^{xi} It should be noted that as a result of the investment efficiency criteria generally adopted for upstream developments, incremental investment will normally only be approved if the incremental profitability exceeds the average profitability of the project. This is a mechanism for ensuring that incremental project expenditure enhances overall investment return – an important consideration in an industry where the relatively few successful exploration efforts have to carry the cost of exploration failure.

^{xii} Certainly it cannot be claimed that upstream competition would be increased as a result of stimulated downstream demand because (i) delivered prices would in this case not be reduced, and (ii) the reductions in mid-stream revenues would only serve to halt any potential growth in gas delivery infrastructure, effectively increasing the barrier to access for potential new regional downstream customers.

contribution to the promotion of competition in a market relevant to criterion (a);

2. Or they are gas volumes that for other technical reasons are not commercially viable without the contribution of some additional external investment benefit. Regardless of at what level the commercial viability threshold exists (and this will change from time to time), there will always be incremental resources which are marginal to develop, and which might be developed if only the profit from their development were to be increased just that little bit more. In this case, it is not just a question as to whether the upstream transfer of profit from gas delivery services (leaving aside the issue of mid-stream service provider viability) has sufficient scope to contribute an adequate subsidisation to make possible the development of marginal gas reserves of significant magnitude. The question still remains as to whether such incremental development would in reality serve to substantially promote competition. Furthermore, there is a question as to whether the impact of such an upstream profit transfer would be such that, given the relative variability in other determinants of upstream gas project viability^{xlii}, a substantial contribution to expanded resource development would result at all. A quantitative analysis of the relative profitability drivers would suggest not.

In addition to considering the limited scope for marginal gas production arising from cross subsidising upstream development at the expense of transmission infrastructure investors (or indeed downstream consumers), the NCC's recent consideration of upstream countervailing market power and the potential for promotion of competition in the upstream dependent market is also noteworthy:

"If the MSP has monopsony^{xliii} power in the upstream market for Cooper Basin gas, it may be able to dictate transportation tariffs to upstream producers. But the MSP's market power may be constrained if:

(a) upstream producers can market their gas to a range of destinations at equivalent prices to those earned on marginal sales to NSW/ACT markets; or

(b) if the producers themselves have countervailing market power."^{xliv}

^{xlii} For example, exchange rate impact on capital cost, technology improvements for enhanced recovery as well as redundancy risks, the overall impact on product pricing for existing major producers from an increased availability of gas reserves in the market, opportunities and risks from forward selling and other hedging activities, and of major significance, the physical availability of an expanded customer demand base in order to underwrite the development of incremental gas reserves (at any price).

^{xliii} That is, the market is dominated by the buyer - effectively the inverse of monopoly power where the market is dominated by the seller – in this case referring to the MSP as being the sole means by which Cooper Basin gas producers can access the predominant Sydney consumer market.

^{xliv} Final Recommendations, Moomba to Sydney Pipeline System: Revocation Applications Under The National Gas Code, NCC, November 2002, paragraph 7.132, page 137.

"In the upstream market, the MSP's ability to exert market power turns on whether the Cooper Basin producers have viable options to divert gas sales into other markets in the event of anti-competitive MSP pricing."^{xlv}

As has been discussed in the earlier section of this application, which provides a description of the upstream market, more than half of Western Australia's gas production is directed towards LNG export. The degree to which gas producers in Australia are currently reported to be competing to each increase their share of LNG export earnings is a clear indication of the relative attractiveness of this particular alternate upstream market for gas. It is not necessary to delve into price differentials to understand this.

In terms of gas deliveries, the GGP transports just 3.4% of the available upstream gas produced and accounts for only 9% of gas delivered via the Western Australian gas transmission network. However, given that gas transmission forms only one aspect of the Western Australian energy transmission network and that the GGP faces direct competition from electricity transmission and remote site, diesel fuelled power generation, the influence which the pipeline has within the market is even further constrained than this figure might imply. Clearly in respect to the GGP, upstream market participants have both alternative markets and countervailing market power available to them.

The Downstream Market

In regard to the downstream market where 90-95% of the gas delivered by the GGP is used to generate electricity, this electricity accounts for only 11% of the total electricity generated within the state.

GGT has been unable to locate any recent publicly available detailed third party information in regard to the available generation and transmission capacity that exists for the delivery of electricity into the Goldfields region. This is hardly surprising given that the electricity market in Western Australia is in a state of some tension associated with the pace and uncertain direction of de-regulation in the electricity generation industry within the state. Nevertheless, it is known that Western Power has some substantial spare transmission capacity to Kalgoorlie, possibly as much as 140 MW, which was bypassed when the GGP originally entered the market. It is also known that plans are afoot within the State to augment power generation capacity, both through a third party power procurement process as well as direct investment by Western Power. In addition, the state's gas distribution utility, AlintaGas has just recently announced a Memorandum of Understanding with Alcoa World Alumina Australia to jointly develop co-generation power plants which will be developed on a staged basis to match growth in the electricity requirements for the SWIS.²²

In the meantime, an indication of the widespread nature of the competition faced by the GGP is illustrated in Map 3 of Appendix 1. Besides the

^{xlv} ibid, paragraph 7.196, page 151.

competition from the SWIS, there also exists a interconnected electricity system in the north west of the state. In addition, the geographical extent of the competition from Western Power's electrical generation capacity is illustrated in Map 6 of Appendix 1.

Of course, in remote areas along the route of the GGP north from Kalgoorlie, gas delivered from the pipeline competes directly against diesel (and to a lesser extent, LPG). According to a report commissioned by the State Government, "in remote locations, diesel can be the only viable fuel source."²³

As has already been discussed in this application, clear market evidence exists in the form of recent projects that have elected to use diesel in preference to gas for power generation, which confirms this statement. In addition, remote third party owned diesel fired power stations continue to be built to augment Western Power's electricity supply network (refer to Appendix 7, Media Releases: "StateWest Power to Supply Mid-West towns").

Relevant to this, it has been observed by the Chairman of the Productivity Commission, Mr Gary Banks, in a recent presentation to regulators, that "the availability of substitutes limits the exercise of market power". Banks goes on to observe,

"A key issue in determining whether competition is adequate is not to get preoccupied with technological descriptions of markets or indeed in mechanically defining markets at all, but on testing the extent of competitive pressure on firms arising from the collective impact of a whole set of substitution possibilities.

....

Even if, individually, services are not close substitutes, collectively they may exert enough discipline to remove any significant scope for excess profits."^{xlvi}

The substitution possibilities to which Banks refers are critically important in the case of the GGP.

The GGP may for the time being be a sole supplier of natural gas into the downstream markets which it serves,^{xlvii} but over 90% of the gas delivered via the GGP is competing directly with electricity or diesel and LPG.

The effects of this competition, within an established energy market in the Goldfields, must be considered in ascertaining whether the GGP is able to significantly influence activity in the upstream and downstream markets. The

^{xlvi} Presentation: The 'baby and the bath water': avoiding efficiency mishaps in regulating monopoly infrastructure, Gary Banks, Chairman, Productivity Commission, 5 July 2002, page 4.

^{xlvii} However, even in this regard, the GGP faces direct pipeline-on-pipeline competition. It should be noted that despite the GGP at Newman being geographically closer to Telfer, it has been unable to economically compete with a new pipeline from Port Hedland for the supply of gas there. This is not really all that surprising however as even disregarding inherent pipeline economies of scale, the total haulage distance from upstream source to an end user at Telfer would be substantially longer via the GGP than the alternative pipeline route. The proponent of the proposed Telfer mine site power station has recently applied to the Western Australian State Government for a pipeline licence to construct and operate a pipeline which will supply natural gas from the Pilbara Energy Pipeline at Boodarie, Port Hedland ("Notice of Application for a Pipeline Licence", West Australian Newspaper, Public Notices, 31 October 2002).

paragraphs which follow, provide an economic analysis which shows that the availability of substitutes for electricity generated from gas, significantly limits the market power of GGT within the Goldfields.^{xlviii}

As noted above (and further explained in the Ventnor Consulting report attached to this submission as Appendix 2), the principal users of energy in the Goldfields are mining and minerals processing businesses. These businesses use energy in the form of electricity, and electricity is available to them from a number of sources including gas-fired generation, the SWIS, and local generating plant fired on diesel or LPG.

For simplicity of exposition, the mining and mineral processing businesses in the Goldfields are assumed to be identical and to produce a single final product. Demand for this product is represented by the market demand curve $p_m(q_m)$. Each unit of final product requires for its production a unit of electricity which, for the present, is taken to be generated from gas. The mining and mineral processing businesses take the price of electricity, p_e , as given in making their decisions about production. In producing the final product, they also use other inputs, acquired at unit cost c_m , and incur fixed costs f_m . The profit of each mining and mineral processing sector business can be represented as:

$$\pi_m = p_m q_m - p_e q_e - c_m q_m - f_m.$$

Each business chooses its level of production, q_m , so as to maximise its profit, π_m , assuming there is no impact on the levels of production of the other businesses. Profit maximisation requires that marginal revenue be set equal to marginal cost:

$$p_m \left(1 + \frac{q_m}{p_m} \cdot \frac{dp_m}{dq_m} \right) = p_e + c_m.$$

Aggregating over n_1 businesses in the mining and mineral processing sector:

$$p_m \left(1 - \frac{1}{n_1 \eta_m} \right) = p_e + c_m,$$

where η_m is the market elasticity of demand for the mining and mineral processing sector. This condition defines, implicitly, the mining and mineral processing sector demand for electricity generated from gas:

$$p_e(q_e) = p_m(q_m) \left(1 - \frac{1}{n_1 \eta_m} \right) - c_m = MR_m(n_1) - c_m,$$

where $MR_m(n_1)$ is marginal revenue as perceived by a business in the mining and mineral processing sector.

^{xlviii} The analysis which follows can be found in a number of books and papers on the economics of industrial structure. See, for example, D A Hay and D J Morris, *Industrial Economics and Organization*, 2nd ed., Oxford, 1991.

Consider, now, suppliers of electricity generated from gas. Each electricity supplier requires gas, gas transportation service, and other inputs. These inputs are available at constant unit cost, c_e , and units are defined so that one unit of input is required for supply of one unit of electricity. The profit of each electricity supplier can be represented as:

$$\pi_e = p_e q_e - c_e q_e - f_e = (MR_m(n_1) - c_m) q_e - c_e q_e - f_e,$$

where f_e is fixed cost. Each business chooses its supply of electricity, q_e , so as to maximise its profit, π_e , assuming no impact on the supply of the other businesses. Profit maximisation requires that marginal revenue be set equal to marginal cost:

$$MR_m(n_1) \left(1 + \frac{q_e}{MR_m(n_1)} \cdot \frac{dMR_m(n_1)}{dq_e} \right) = c_e + c_m.$$

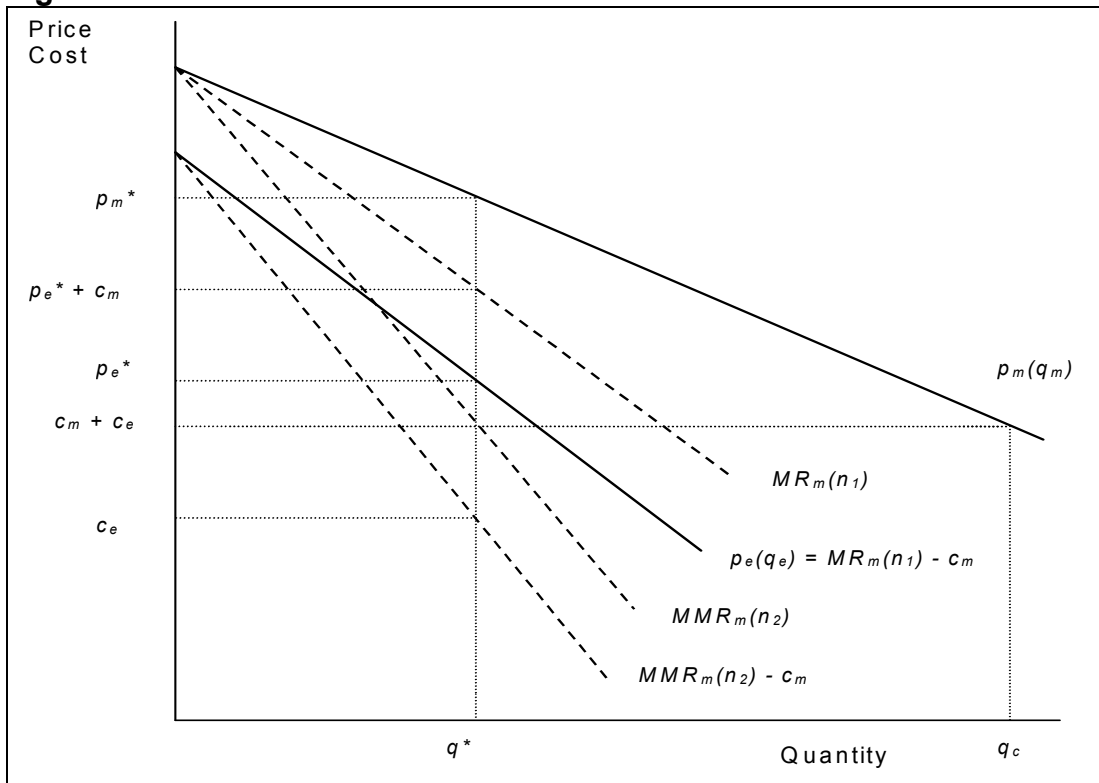
Aggregating over n_2 businesses supplying electricity generated from gas:

$$MMR_m(n_2) = MR_m(n_1) \left(1 - \frac{1}{n_2 \eta_{MR}} \right) = c_e + c_m,$$

where $MMR_m(n_2)$ is the marginal curve to the marginal revenue curve perceived by each of the mining and mineral processing businesses. $MMR_m(n_2)$ is the marginal revenue curve perceived by businesses supplying electricity generated using gas, and η_{MR} is the elasticity of that curve.

These relationships are further explained using the diagram below.

Figure 2.



For each of the n_2 suppliers of electricity generated from gas, $p_e(q_e) = MR_m(n_1) - c_m$ is the (derived) demand curve for the electricity they supply to the mining and mineral processing sector. For profit maximisation, each sets $MMR_m(n_2) - c_m = c_e$ and, in consequence supplies q^* units of electricity. By reference to the (derived) demand curve, they sell this electricity at price p_e^* .

Similarly, for profit maximisation, each of the mining and mineral processing businesses equates perceived marginal revenue to marginal cost: $MR_m(n_1) = p_m + c_e$. They produce q^* units of final product at price p_m^* .

If both mining and mineral processing and the supply of electricity generated from gas are monopolistic (n_1 and n_2 are small), a margin is added to price in each link of the supply chain. (In the mining and mineral processing sector the margin is measured by $\frac{1}{n_1 \eta_m}$; in electricity supply it is measured by $\frac{1}{n_2 \eta_{MR}}$)

These successive margins have the effect of reducing the output of the final product from the mining and mineral processing sector below the level that would have resulted if markets had been competitive ($q^* < q_c$).

If both mining and mineral processing and the supply of electricity generated from gas are competitive (because the numbers of businesses in each

activity, n_1 and n_2 respectively, are large), the margins approach zero, and both $MR_m(n_1)$ and $MMR_m(n_2)$ coincide with the market demand curve for the final product $p_m(q_m)$. Both businesses in the mining and mineral processing sector, and suppliers of electricity generated from gas, price their outputs at marginal cost, and the level of output of the final product from the mining and mineral processing sector, q_c , is a maximum.

The degree of competition in the downstream mining and mineral processing sector is not an issue for GGT. Nevertheless, from its discussions with users and potential users of the GGP, GGT believes the downstream market to be highly competitive. Markets for the final products of the mining and mineral processing sectors in the Goldfields are competitive international markets.

What is critically important in the case of the GGP is the degree of competition in the market for electricity. There are close substitutes available for electricity generated from gas: electricity from the SWIS, and electricity from local generating plant fired on diesel or gas.

If suppliers of gas, and the GGT as supplier of gas transportation services, price at levels above cost, electricity generated from gas will not be competitive with electricity supplied from other sources. Suppliers of electricity generated from gas will substitute electricity generated from those other sources.

In terms of the diagram above, the (derived) demand curve for electricity generated from gas will no longer be the curve

$$p_e(q_e) = p_m(q_m) \left(1 - \frac{1}{n_1 \eta_m} \right) - c_m = MR_m(n_1) - c_m .$$

The elasticity of the (derived) demand curve for electricity generated from gas is

$$\eta_e = k_e \eta_m + (1 - k_e) \sigma ,$$

where k_e is the share of electricity generated from gas in the total payment for inputs into the production of the mining and mineral processing sector, and σ is the elasticity of substitution between electricity generated from gas and other inputs, including electricity supplied from other sources.^{xlix}

It is GGT's view, for reasons set out later in this submission, that k_e is small. Furthermore, with close substitutes available for electricity generated from gas, σ is large. In consequence, the elasticity of demand for electricity generated from gas is large. In these circumstances, any market power in the supply of electricity from gas is significantly reduced.

^{xlix} This is a well established proposition in microeconomic analysis. See, for example, P R G Layard and A A Walters, *Microeconomic Theory*, McGraw-Hill, 1987.

GGT acknowledges that any market power in the supply of electricity generated from gas may not reduce to zero. However, its experience in the energy market in the Goldfields clearly indicates that close substitutes exist. It is a fact that these substitutes compete effectively with the GGP. Therefore any ability which the GGT may appear to have to exercise market power in the downstream market is severely constrained.

These constraints exist for a number of reasons. Firstly the price of delivered gas at the southern end of the GGP is capped at a level required for power generation in the Kalgoorlie area to be competitive with power delivered via the large scale SWIS infrastructure. As tariffs on the GGP are calculated using a distance based methodology (as is generally the case with longer pipelines), and the upper limit is set by the tariff in the Kalgoorlie area, customers along the GGP have a tariff reflective of the competitive energy market in Kalgoorlie. Thus, even should the GGP have market power along the route of the pipeline, this distance based pricing methodology precludes any misuse of any possible market power.

Secondly, for remote sites, natural resource projects simply default to diesel as they did prior to GGP being built.

The cost of delivered gas is determined by the purchase cost of the gas from the producer or gas trader, plus the cost of transportation along the GGP, as well as the full amortised cost of whatever dedicated lateral pipeline is necessitated. However because of the relative magnitude of the cost of gas in the market serviced by the GGP, gas delivered from the GGP can only compete where projects are,

- (1) fortuitously located in close enough proximity to the pipeline, and,
- (2) have a sufficiently large enough load demand (in terms of both magnitude and expected duration) such that the cost of a lateral becomes viable.

Only after these conditions are satisfied, can the “economics of catchment” be assessed. This includes such competitive economic hurdles as the trade-off between capital expenditure and operating costs. Building a pipeline lateral and installing gas power generation involves high immediate capital cost, which is offset by lower future operating cost. However the time value of money and the negative impact on project economics from accelerated expenditure combine, along with aspects of investment life and certainty, to favour the lower upfront capital cost associated with diesel power generation or connection to existing power transmission, despite the associated higher future operating cost. Even if, having addressed the economics of investment options, the pipeline lateral option is still viable, the investment decision will still be strongly influenced by the cashflow constraints and funding capabilities of the individual downstream projects and their investors.

It is GGT’s contention that even if the cost of gas delivery were equal to zero (that is free), no new downstream projects within the relevant geographical region would ensue. It is conceivable that some existing projects for which the

conversion to gas is marginal might switch fuel sources (although this is highly dubious, based on GGT's market experience), however the overall impact that this would have on the promotion of competition is insignificant, if not non-existent.

In fact, GGT has attempted to test this hypothesis in an open letter to customers, regional and industry authorities, and relevant State Government ministers. The letter sought to elicit a response from any party who might have a project or concept for which a favourably negotiated gas transmission price might help to facilitate development.ⁱ Unfortunately, while the prospect of sharing the benefits of a greater economy of scale in regard to their existing contracts piqued the interest of a number of existing users, it elicited no productive responses in regard to the prospect for new developments to proceed.

It is relevant to note that the original GGP tariff path was developed by the pipeline's original, vertically integrated owner-users in full recognition that, even in the event that they might one day divest their respective interests in the pipeline asset, they would almost certainly continue to make up the bulk of the customer base for the pipeline's services. This situation has of course since eventuated, and the original owner-users do in fact now comprise approximately 75% of current GGP contracted gas deliveries.ⁱⁱ This provides considerable ongoing market leverage in the hands of only three customers (out of a total of only ten customers directly served by the pipeline). Clearly these customers wield a significant degree of countervailing market power.

(iv) Coverage will not promote the conditions for any increased competition in any other market.

GGT contends that the application to GGP of coverage under the Code will not promote any further competition in any market relative to the circumstances that existed prior to the application of the Code. As previously discussed in detail, the terms and practicability of third party access on commercially sound terms were already established prior to the Code. Nonetheless, for the purposes of this application, GGT is compelled to evaluate the potential for the promotion of competition relative to that potential in the absence of the application of the Code, for markets both upstream and downstream of the GGP.

The Upstream Market

As has already been discussed in this application, GGT contends that the GGP does not have the capacity to play a significant role within the context of the development of the upstream supply market in Western Australia.

ⁱ This is discussed in greater detail in the following section of this application. The letter is included in Appendix 4.

ⁱⁱ Refer to Map 2 in Appendix 1 of this application.

Nonetheless, the issue of the role of the GGP and the future impact of coverage under the Code for increasing competition in the upstream market is a matter which is pivotal to addressing criterion (a).

The preceding section (iii), discusses the extent to which the GGP is constrained in its ability to engage in monopoly pricing and its inability in the face of counter-veiling market power (particularly the presence of substitutes) to significantly influence the relevant markets. Clearly market participants both upstream and downstream will welcome any cost reduction which might improve their own profitability. For them, this is good business as a dollar saved is generally worth more than an additional dollar earned, as the latter will invariably require some incremental investment to achieve and hence result in a lower net return.

For upstream market participants, reduced gas delivery costs combined with unchanged delivered cost of gas to consumers means that the greater level of profitability they see can elevate marginal incremental projects into the category of being viable investments. Besides the question as to whether or not this would result in market growth which was either significant, or which served to promote competition, there remains the issue of a need for a customer base to underwrite any such growth in production. The preceding section (iii), also discusses the evidence which strongly indicates that such growth in the downstream demand for gas is unlikely to be realised (for reasons which are further discussed in the following section) as a consequence of merely reducing gas transmission prices.

Furthermore, it should be noted that price, and in particular a differential from a potentially lower regulated price, cannot be relied upon as an indication of monopoly power. The reliance upon a theoretically derived, public benchmark price, which can be varied by private negotiation anyway, is completely inappropriate for this purpose, as noted in the EGP Decision, in which the Tribunal stated that:

“This argument (that the presence of a difference between a potential regulated price under the Code and the price offered by the EGP as the service provider is an indication that there is not efficient competition) does not take sufficient account of the fact that regulation is a second best option to competition. The complex nature of the tariff-setting process, the number of assumptions it relies on, and the fact that the reference tariff is a publicly available price which may be varied by negotiation between the pipeline owner and user depending on the user’s requirements and conditions in the marketplace, all point to the fact that the reference price is not necessarily the price which would result from competition. Indeed, ACCC in its Draft Decision on MSP tariffs pointed out that if the EGP did not exist the reference tariff for the MSP would be lower as it would be transporting more gas. This is not what one would expect in a competitive market (Draft Decision at 97).”^{lii}

This being the case, reducing regulated benchmark gas transportation prices as a mechanism to reducing delivered gas prices, will have minimal (if any)

^{lii} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, para 110.

subsequent effect on increasing the downstream gas demand that is necessary to drive increased upstream gas production and hence the circumstances for increased upstream competition. On the contrary, it can be concluded that the critical determinant in the promotion of upstream competition, at least in so far as a regional market is concerned, is the accessibility of new users to alternative gas suppliers.

In his GGP Draft Decision, the Regulator has responded to a number of concerns expressed by both upstream²⁴ and downstream²⁵ gas transmission users in regard to the possible accessibility or otherwise of upstream supply into the GGP. In his appraisal, the regulator notes that it would not normally be appropriate to mandate an interconnection service between pipelines, but as a precautionary measure, he concludes by requiring a specific amendment to the proposed GGP Access Arrangement to accommodate multiple inlet points to the GGP.²⁶

However upstream access to the GGP via the DBNGP was already envisaged within the pre-existing access provisions of both the DBNGP and the GGP. In 1999, prior to the submission of even proposed access arrangements under the Code for either pipeline, the Regulator had noted that there were;

“no significant restrictions to multiple Receipt Points and Delivery Points in Service Agreements for the Dampier to Bunbury Natural Gas Pipeline or the Goldfields Gas Pipeline.”^{liii}

In fact, the GGP State Agreement already provides for access to and interconnection (if required) of the GGP and the DBNGP, to the extent required to facilitate access by gas suppliers to the GGP. This is detailed in clause 17 of the State Agreement.²⁷

From the preceding commentary and consideration of clause 17 of the State Agreement, it is apparent that access (on technically sound and commercially fair and reasonable terms) to the GGP by gas suppliers was established prior to the introduction of the Code. Furthermore, the pre-existing provisions allow for all conceivable gas delivery routes, whether directly into the GGP, or via any portion of the DBNGP, such that the GGP inlet point could be anywhere between its northern-most end and any intermediate point which coincided with a new interconnecting pipeline (such as that proposed for the Mid-West of the state).

Thus (as the operator of the DBNGP also points out)²⁸, with the rights of access already established, all that remains in order for the interconnection of gas suppliers to be effected, is the commercial imperative.

The Downstream Market in General

^{liii} Draft Decision: Access Arrangement: Parmelia Pipeline, Independent Gas Pipelines Access Regulator, Western Australia, 27 October 1999, section 6.2.3, page B-27.

It should be recalled that the GGP became subject to the Code on 9 February 1999. The regulatory process under the Code since that date has only progressed to the point of the Regulator having issued his Draft Decision in regard to the proposed access arrangement for the GGP. Hence the regulatory process under the Code is incomplete and as a consequence, it cannot be argued that any benefits can be attributed to coverage of the GGP to date.

Moreover, on the 6 November 2002 and subsequent to the decision of the Supreme Court of Western Australia in regard to the DBNGP Draft Decision,^{liv} the Regulator issued a notice indicating his intention to revise the Access Arrangement approval process and to amend his Draft Decision issued on the 10 April 2001 with respect to the GGP.^{lv} The Regulator has proposed a three stage process prior to the release of a subsequent Final Decision in regard to the GGP which will include recognition and application of sub-section 97(4) of the Act and clause 21(3) of the State Agreement. The Regulator has stated his intention to then provide an assessment of the extent to which the Code applies to the GGP. In this process, the Regulator will also reconsider his approach to various provisions of the Code in light of the Court's finding of certain errors of law made in his DBNGP Draft Decision, and the Regulator's recognition that those errors, to a large extent, were also made in relation to the GGP Draft Decision.

The Regulator has stated that he will amend his Draft Decision after reconsidering previous submissions before him, as well as consideration of new submissions and other additional information that he intends to seek. This proposal to re-issue the GGP Draft Decision effectively recommences the approvals process for the GGP and, for the purposes of this application, negates any validity the Draft Decision might have had as an indicator of the circumstances which might be expected to prevail under the Code.^{lvi}

In order to evaluate the future potential for the Code to improve the prospects for promotion of competition in downstream markets, it is necessary to review the competitive context in which the GGP was developed and continues to exist.

As has been discussed previously, the construction of the GGP represented a major regional development project which resulted in the introduction to the markets it is able to economically reach, of a previously unavailable alternative source of competitive energy.

^{liv} Dr Ken Michael AM; Ex Parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, Supreme Court of Western Australia, 23 August 2002.

^{lv} Notice: Proposed Access Arrangement for the Goldfields Gas Pipeline, Ken Michael, Acting Gas Access Regulator, Office of Gas Access Regulation, 6 November 2002.

^{lvi} Notwithstanding that the reasons provided in the Court's decision relating to the DBNGP Draft Decision themselves have a direct bearing on previous reliance upon interpretations contained in draft decisions generally, concerning the role, objectives and meaning of particular references in the Code to 'efficient costs', 'economic efficiency' and the pursuit of 'competition'.

It is relevant to the context of this application to refer to the recent parallels and distinctions with the Tribunal's consideration of the EGP relative to the NCC's consideration of the MSP Revocation Application (emphasis added):

7.297 The Council notes EAPL's stated intention to pursue pricing that does not discriminate against regional customers. However, the Council cannot rely on a stated intention as conclusive evidence that this position will be maintained if coverage of the MSP is revoked. It is therefore appropriate for the Council to have regard to the incentives facing the pipeline owner.

7.298 In the Duke EGP decision, the Tribunal was not convinced that access was necessary to promote competition in regional markets south of Canberra, despite the fact that the EGP was the only provider of pipeline services to those areas. The Tribunal found that monopoly behaviour was unlikely due to the publication of nondiscriminatory tariffs, and commercial incentives for the EGP to develop new markets by attracting customers away from other energy sources (Duke EGP decision 2001, paragraph 132).

7.299 The Council notes that the circumstances for regional markets along the route of the MSP differ from those served by the EGP. In particular, regional markets served by the EGP were not previously served by any pipeline. The Tribunal said, with reference to arguments put by Mr Ergas (of NECG):

... as gas has not previously been available, the ability to monopoly price would be restricted because potential users have bargaining power, the costs of conversion to enable the use of gas are significant, and EGP has committed assets which it has incentives to use. In other words, the prices of existing forms of energy will be a countervailing force on the price of gas and pipeline services... (Duke EGP decision 2001, paragraph 129).

7.300 In contrast, regional markets along the route of the MSP are established markets that have been served by the pipeline for over 20 years. Hence, the MSP may not necessarily face the same commercial imperatives to develop new markets through efficient tariffs as may be faced by the EGP.

7.301 Ordover and Lehr consider the case for coverage to be especially strong with respect to regional downstream markets:

... some regional markets may only be served by the MSP and the ability to deliver gas via alternate pipelines or by some other means may be quite limited for the foreseeable future. Those areas within NSW and the ACT for which the MSP is the only feasible source of supply may benefit from coverage if it leads to lower transport prices and assured access to the pipeline (Ordover and Lehr 2001, p.18)."^{lvii}

It is quite clear that the GGP shares many of the regional market attributes of the EGP identified above in that it:

1. Introduced gas into a regional market were it was previously unavailable,

^{lvii} Final Recommendations, Moomba to Sydney Pipeline System: Revocation Applications Under The National Gas Code, NCC, November 2002, paragraphs 7.297 to 7.301, page 176.

2. Is constrained by the countervailing force of the price (and availability) of existing forms of energy,
3. Is bound by the principles of non-discriminatory third party access,
4. Has published non-discriminatory tariffs^{lviii} (established in this case in accordance with government approved tariff setting principles), and
5. Has commercial incentives to develop new markets by attracting customers away from other energy sources (notwithstanding the practical difficulties it has encountered in doing so).

From the outset, the nature of the downstream competition that the GGP would face was recognised as being the market for electricity. The then Minister for Energy stated;

"The pipeline operator will face competition from SECWA and vice versa."^{lix}

The anticipated impact of the cost savings in energy from the introduction of gas into the downstream market was significant, with estimated reductions in the order of around 15% in Kalgoorlie and 30% at Mt Keith.²⁹ In fact, the Energy Minister at the time was forced to address concerns within the State Government about the necessity of the State energy utility reducing prices in order to compete with the proposed gas pipeline.³⁰

However, it was also clear that the potential field of competition was not restricted to electricity supplied by SECWA from the SWIS. Competition between power station fuels, particularly diesel, was also provided. This was also clearly recognised from the outset.³¹

What is more, the benefits anticipated prior to the construction of the GGP have subsequently been realised. Gas delivered to Kalgoorlie has displaced electricity which was previously provided via transmission line³², and downstream customers have reaped the benefits.

Typical of the time was a comment made in 1997 by a Goldfields gold miner in regard to reported production cost savings achieved by Wiluna Mines Ltd.

"With a switch to gas-fired power generation due later this month, Wiluna's managing director Jeff Gresham said the September quarter performance would not be a one-off result."

"We are confident that these cost levels will be maintained, particularly with the commissioning of the gas-fired power plant in October, which is expected to yield savings of around \$27/oz," he said."^{lx}

lviii Refer to the GGT website (www.ggt.com.au) for current published tariffs, pricing principles, as well as standard terms and conditions.

lix Mr. C.J.Barnett, Hansard, 6 April 1994, page 11584, Second Reading.

Since then, the dominant existing downstream customer on the GGP has stated that the energy costs of its Western Australian operations in 2001 were 5% below 1995 energy costs in nominal terms, which it equated to a 20% reduction in real terms. This was quoted as amounting to savings of more than \$25 million p.a., while also avoiding exposure to diesel price shocks.^{lxi}

However GGT notes the view expressed by the NCC that;

"the "promotion of competition" test should not be assessed in terms of the effect on particular competitors. Rather, criterion (a) focuses on the impact of coverage on the broad competitive environment in the dependent market (Sydney Airport decision 2000, paragraph 106). If the dependent market is already effectively competitive, it would be difficult to argue that regulated access [under the Code] would improve the competitive environment. The Council accepts that Australia's export and import-competing industries tend to be exposed to a competitive international environment. In this sense, while regulated access [under the Code] may improve the competitiveness of particular Australian firms, it is not apparent that coverage would enhance the broader competitive environment in the markets in which those firms operate."^{lxii}

In this context, it should be noted that in a company statement released in March 2002, the CEO of WMC (which single customer represents approximately half of the total load of the GGP) stated:

"We still hold the view that WMC is the most profitable nickel producer in the world and independent analysts such as Brook Hunt support that view. The return on net assets for our nickel division in 2001 was 19.1 per cent and that's not a bad figure in a poor market."^{lxiii}

The Department of Mineral and Petroleum Resources summarised the existing situation (with emphasis added) thus:

"Overall, Western Australia presents great opportunities for business investors that require reliable and competitively priced natural gas for downstream processing projects."^{lxiv}

Despite such positive indications as to the effectiveness of the competition already achieved by the introduction of gas into the downstream market for energy, claims are occasionally made that much greater reductions to gas transportation prices are necessary in order to promote the development of downstream activities. The following example is typical:

^{lx} It should be noted that this represents a saving of approximately 8% in nominal terms attributable to the delivered cost of gas which needs to be considered in the context of a reported 23% cost saving in the preceding quarter (to \$328 per ounce) due to other operational factors. "Lean, mean Wiluna fights takeover", in Gold Gazette, 20 October 1997, page 28.

^{lxi} Presentation : WMC's Involvement in the Goldfields Gas Pipeline, John Harvey, Manager Energy Supply, WMC Resources, 12 March 2002.

^{lxii} Final Recommendations, Moomba to Sydney Pipeline System: Revocation Applications Under The National Gas Code, NCC, November 2002, paragraph 7.40, page 113.

^{lxiii} Open Briefing: CEO Mr H.Morgan on Profit & Outlook, WMC LIMITED, 14 March 2002.

^{lxiv} "Big reserves, big prospects", Prospect Magazine, Department of Minerals and Petroleum Resources, Government of Western Australia, March-May 2002, page 7.

“Further, Anaconda has studied non metal projects which are extremely sensitive to gas prices, such as the Mt Weld Phosphate Project where gas prices are approximately 20% of the overall cost.”³³

In addressing such claims as these, it is instructive to consider the relative magnitude of the various cost and revenue contributions to the overall economics of the proposed project, as well as variability in these factors. This is necessary in order to make an assessment as to the significance of the cost impact of gas transportation, and hence the significance of its ability to promote either profitability or competitiveness (whether or not these are related – a proposition which is debatable).

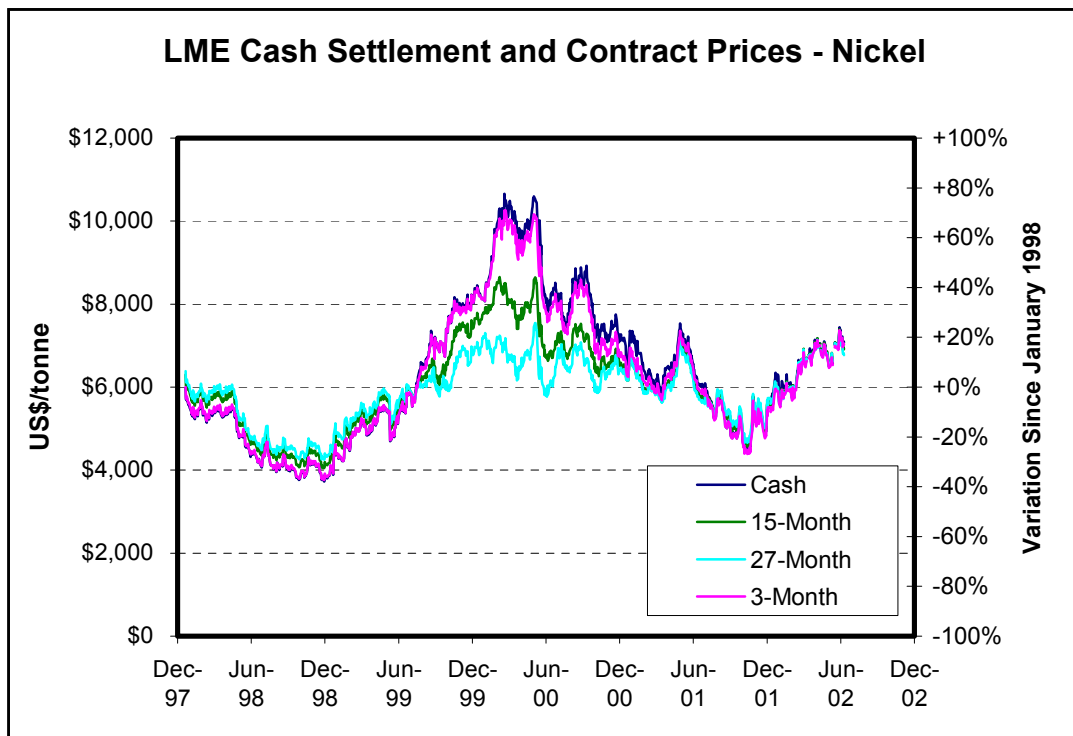
In respect to the preceding quote, it should be considered that the cost of gas transportation represents approximately 50% of the delivered cost of gas. Hence, if “gas prices are approximately 20% of the overall cost”, the transportation element is approximately 10% of overall cost. Thus if the gas transportation tariff were to be reduced by even as much as 30%, the effect of the reduction would represent a 3% on the overall cost of the customer’s project. The question of whether a proportional reduction of this magnitude would contribute positively to the promotion of downstream competition must include consideration of the relative impact it would have on the pipeline investor. If downstream competition were realised, and this resulted in increased regional demand but the pipeline investor was now deterred from investing in new capacity to accommodate the increased demand, then the benefits would be negated.

In this example, the gas transportation price reduction would have a significant impact on the transportation revenue derived by the Service Provider with a significant detrimental effect on the viability of future pipeline expansions, if not current operations. The question becomes then, would a 3% operating cost reduction provide a significant improvement in the downstream customer’s profitability, and even if so, would this have any effect on the conditions for competition in the market in which that customer was engaged?

To answer this question, it is necessary to consider both the impact upon the user’s bottom line profitability, as well as how this impact compares against other major influences upon the customer’s business.

In recent times, mining companies serviced by the GGP have accounted for substantial variations in the profits they have reported by citing world commodity price variations in the order of approximately 10-30% for nickel, gold, copper and aluminium.^{34 35 36} The volatility in commodity prices underlying these statements is borne out (for nickel, the main downstream commodity affected by the GGP) by the data illustrated in the following graph.

Figure 3.



Source: London Metals Exchange (www.lme.com)

If it is also considered that, for instance, for the year ended June 2002, WMC generated nearly \$943 million in cash flow from operations,³⁷ then the significance of the previously quoted \$25 million p.a. energy cost saving as a “project driver”, can be put into an appropriate context. It represents 2.7% of the company’s pretax cash flow. This figure then needs to be evaluated against the previously referenced commodity price fluctuations reported by the company as varying between 10% and 31%. The impact of these fluctuations is directly comparable in terms of bottom line revenue variations, and it can be seen that a 2.7% cost saving appears highly unlikely to alter the competitiveness of even an individual participant in such a volatile and already competitive international market.

Furthermore, in order to put the relative magnitude and hence economic significance of the quoted energy cost saving into full perspective, other non-operational costs should also be considered. In this regard, WMC reported currency and commodity price hedging losses in 2001 of \$282 million, with an expectation of around a further \$130 million loss per year for the next six to seven years.³⁸

It can be seen that WMC’s hedging losses alone vastly outweigh any possible significance of even substantial reductions in the company’s gas transportation costs.

These examples are consistent with the experience of anyone who is familiar with the commercial economic evaluation of resource projects, where the capital expense of a project is generally the dominant, and usually

significantly so, determinant of viability and profitability (although the cost of borrowing funds may also be significant). Operating costs generally have a much smaller relative impact on project economics. The preceding examples illustrate that gas cost is typically only one diminutive component of total operating expenditure. The ability of any adjustments to the gas transportation cost element to influence project competitiveness (even if it is accepted that this is the effect which results from such cost reductions), is very limited. This needs to be compared to the positive enabling effect on project investment decisions from having reliable and accessible gas available for use by a new project.

There is a need to recognise that the inherent initial disadvantages of gas transmission (by virtue of its high initial committed capital requirement and the 'sunk' nature of the investment) are in tension with the need for initial investment in infrastructure. The hurdle of available accessibility to gas has to be surmounted before the relevant downstream market growth can occur. Only once the infrastructure is in place, can the market develop and grow so that competition can begin to bring about sustainable price reductions. These considerations are nowhere less appreciable than they are in Western Australia, as the following parliamentary statements illustrate.

"Members opposite ask why our gas [in Western Australia] is dearer [than elsewhere in Australia]. There are a number of reasons: The main difference is that we are servicing a market of approximately 1.8 million people^{lxv}, and in the eastern States the market for gas is probably 12 million to 14 million people. The capital cost of building a pipeline is offset much more quickly when one operates in a larger market."^{lxvi}

"Real prices have come down. I recognise that there is still a margin, but, again, as the member for Geraldton said, we need to understand the geography of this State. Our coal is expensive, for historic reasons, and is of lower value. It is not the surface deposit that is easily mined elsewhere. Our gas is abundant, but it is 1,500 kilometres away and is 120-odd kilometres out to sea; therefore, it is expensive and needs to be transported a long way. WA has a narrow market, and it has one principal population centre - Perth. We have a responsibility to provide power into regional areas, not just the isolated regional areas, but also the south-west grid area. That is a non-economic service, but we have a social responsibility to do that."^{lxvii}

"The member for Albany would like to see gas delivered to Albany, and that is probably subeconomic. Gas delivery into the mid-west is subeconomic, and that is why the Government is assisting Western Power in that provision."^{lxviii}

It was clear, prior to the introduction of the Code, that there was an appreciation within government of the notion that access regulation, to the extent that it might promote competitive price behaviour, was constrained by the nature of the Western Australian market and its geography. Achieving lower prices through competitive processes was certainly an objective of the

lxv In fact, the portion of the downstream market directly serviced by the GGP is a substantially small portion of this customer base.

lxvi Mr BLOFFWITCH, Hansard, Wednesday, 16 September 1998, p.1470.

lxvii Mr BARNETT, Hansard, Wednesday, 16 September 1998, p.1473.

lxviii Mr BARNETT, Hansard, Wednesday, 16 September 1998, p.1475.

Government. However it was recognised that before the situation conducive to achieving this outcome could be established, infrastructure development had to take place. It was also recognised that this could only happen in Western Australia if sufficient investment sureties were provided, whether by direct investment incentives, government guarantees of commercially attractive rates of return, or by underwriting demand growth.

"An investment is being made for the future of this State. That is exactly the vision these people had; they made an investment for the future benefit of the people in this State. In doing so, a very courageous decision was made. As we bring more pipelines on stream, as we get more gas out and as more large industries are established, we will start to see gas prices come down. Surely in the future these people will not have a hard job. They will help us to reduce energy costs in this State. That is a very positive step and something all people in this State should all support."^{lxix}

Comments contained in the final feasibility report for the Murrin Murrin project, issued in 1996, provide evidence of the positive contribution of having accessible gas infrastructure. The report states;

"The Project is well serviced with existing infrastructure and only minimal capital is required for non-plant items. The cost and lead time saved by this infrastructure is an additional competitive advantage of the Murrin Murrin deposit compared with laterites in tropical regions."^{lxxx}

Clearly, the emphasis of this statement is that it was accessibility to existing and available infrastructure that was attributed to having promoted competitiveness. It is also noteworthy that the economic sensitivities published in this report made no mention of the sensitivity of the project to the cost of gas, although it did give consideration to commodity price fluctuations.

Direct Gas Use Market (Industrial Process and Domestic Consumption)

As has been discussed previously in this application, approximately 5-10% of the gas delivered to the downstream market via the GGP is utilised for its inherent quality as gas (as opposed to being consumed as an energy source for generating electricity). It should be noted however that the transportation prices established on the GGP are determined by the market forces that prevail in the competitive energy market at the southern end of the pipeline at Kalgoorlie. Both the GGP and the SWIS, which service this market, have available additional capacity and the power generation capacity of the SWIS is growing.

Gas consumers who use gas for industrial process purposes, in particular get the benefit of the prices established in the more competitive downstream electricity market. This is also true for GGP's retail gas distribution customer, although whether the benefits of this competitive pricing get passed on to the final domestic customers is outside of GGT's influence.

^{lxix} Mr BLOFFWITCH, Hansard, Wednesday, 16 September 1998, p.1470.

^{lxx} "Murrin Murrin Nickel / Cobalt Project: Summary of Final Feasibility Study", Anaconda Nickel, May 1996, page 15.

For this gas-use market segment in particular, it is relevant to consider the nature of the elasticity of demand which characterises the downstream market serviced by the GGP.

In this regard, in 1999, the Australian Bureau of Agriculture and Resource Economics (ABARE), in conjunction with the Australian Gas Association (AGA), published a study of the general responsiveness of gas (and electricity) demand to gas (and electricity) prices, which included a review of preceding studies.^{lxxi}

The report found that the demand for gas is relatively price inelastic, in both the short run and the long run. The report also found that the cross price elasticities of energy demand were characterised by a relatively high responsiveness of gas demand to changes in electricity prices. That is, if electricity prices fall, customers are quite willing and able to substitute out of gas. In contrast, they are less willing or able to reduce their consumption of electricity if gas prices fall. The report concludes that this reflects relatively limited substitution possibilities, that is, there are some applications for which electricity will continue to be used even if gas prices fall.^{lxxii 39 40}

Inelasticity in the market for gas sourced via the GGP means that reducing the delivered price of gas to GGP end users will not lead to substantial increases in gas demand, which in turn means that reductions in gas transport costs will not materially promote competition between gas consumers. The overall conclusion of the report was that energy demand, and gas demand in particular, is not particularly responsive to price reductions.⁴¹

General Market Responsiveness to Gas Transmission Price

The conclusions of the ABARE/AGA study have also been empirically tested by GGT and confirmed as characterising the broader downstream market responsiveness to price reductions. As illustrated in the previously referenced chronology in Attachment 1, the GGP has a history of tariff discounts intended to promote pipeline usage and market development. The most recent and widely publicised initiative was the EDT promotion, offered just prior to the commencement of the access arrangement process required under the Code.

As has been demonstrated previously in this application, the GGP is currently effectively fully utilised at its existing capacity configuration. However, subsequent expansion can be undertaken at marginal cost which will result in

^{lxxi} This study specifically excluded the use of gas used as fuel for electricity generation, hence its applicability to the GGP is limited, and most relevant to the direct gas use segment of the downstream market. However, it is worth noting that the report's findings are broadly consistent with GGT's own market experience.

^{lxxii} This situation is also true of the mining operations supplied by the GGP. Gas can not displace electricity in a number of critical functions (to drive air conditioners, the motors driving ball mills and conveyor belts, etc.) and hence, even where gas is utilised, electricity is required. This goes to the heart of the previously discussed descriptions of the relevant markets, where we have seen that the vast majority of the gas delivered by the GGP is consumed for electricity generation.

overall cost reductions. GGT may be the sole supplier of natural gas to the Goldfields for the present (albeit in the face of competition from close substitutes for the service it provides). However, as long as GGT is free to exercise its capacity as sole supplier and engage in benevolent price discrimination, it is able to promote further capacity utilisation based on marginal pricing,^{lxxiii} at least in the short term.⁴² This must be viewed as not only being a legitimate business interest for GGT, but as a desirable outcome for the promotion of regional development.

This is the basis upon which the EDT programme undertaken by GGT in 1999 was predicated. A specific account of the initiative can be found in Attachment 6 to this application. Unfortunately the EDT initiative only served to demonstrate a marked failure of the downstream market to respond to an offer to provide gas transportation at what was effectively marginal cost, thus reinforcing the view that the broad gas demand in the downstream market served by GGP is notably price inelastic.

More recently, in an open letter to the market, GGT made the following offer:

“Market evidence, reinforced by the poor response elicited by the recent EDT offered by GGT, indicates that there are no new projects on any scale for which the cost of gas transportation is a critical determinant of viability.

*To put the argument in the extreme, even if GGT were able to offer a gas transportation service **for free**, the evidence available to GGT indicates that this in itself would not precipitate one single new business venture proceeding. The only economic effects that would result would be to increase the profits of existing businesses and a possible loss of business for diesel fuel supply companies and diesel delivery drivers.*

Obviously offering to transport gas at no cost is not a commercially viable option, however GGT would be most grateful to hear from the proponent of any new business who considers that the viewpoints offered in this section are erroneous. GGT would welcome the opportunity to explore how it might be able to work cooperatively to contribute to the viability of any new undertaking.^{lxxiv}

This submission, published on the Productivity Commission website, the Regulator’s website and individually sent to relevant State Government ministers, regional downstream industry associations and GGP’s existing customers, also failed to elicit any commercial response from proponents of potential (or indeed any) projects.

This lack of response tends to confirm the contention that gas transportation cost has a relatively insignificant ability to influence the overall viability of downstream projects. Further, it is possible that the variability of other factors upon which a downstream project might be dependent, could substantially outweigh any positive contribution from any overall cost saving as might feasibly result from even substantial reductions to gas transportation tariffs.

lxxiii Although it cannot be compelled to do so under either of the regulatory regimes to which it is subject.
lxxiv GGT Submission to the Productivity Commission Review of the National Access Regime, 10 July 2001 (see Appendix 4).

While some problems have been noted with the broader applicability to GGP of the ABARE/AGA study into gas elasticity, it is noteworthy that the report concludes (in so far as it goes) that the elasticity of gas demand to gas price is close to zero in the mining sector.⁴³

A final reference to the ABARE/AGA report is warranted. The report makes the following important observation (with emphasis added);

“Another important factor influencing the growth of gas consumption has been the increasing availability of gas at competitive prices, reflecting the growth of the pipeline network. Further growth in the gas share of the energy market is expected as the pipeline network expands and gas markets are opened up to more competition.”^{lxxv}

There is a pivotal recognition in this statement that the promotion of the gas share of the energy market relies on something more than simply establishing rights of access for new users, or reducing price paths. The initial availability of gas and expansion of network infrastructure is vital, particularly if new regional markets are to ever enjoy the benefits of reticulated gas supply. While the observation in regard to the potential for the gas share of energy markets to grow as gas markets are opened up to competition, may be valid in markets that were formerly dominated by monopoly franchises, this is not the situation which has ever existed in respect to the GGP.

To the extent that growth in the gas share of the energy market contributes towards conditions which promote competition, these findings indicate that expanding gas consumption is predicated mainly by the continued expansion of accessible gas infrastructure. As the gas alternative expands, improving the economies of scale for transmission as it goes, gas is made sustainably available – both physically and economically - to new gas users. It is certain that this is what will drive any growth in the gas share of an energy market (at least in respect to a regional market such as the GGP operates within) in a way which cannot result from simply attempting to provide the existing customer base with reduced prices and windfall profits.

This is certainly the commercial experience of GGT and is confirmed by statements by government and upstream interests. According to the Western Australian Department of Mineral and Petroleum Resources (now DoIR);

“The availability of natural gas, reticulated through industrial-sized pipelines through much of the State, has provided a firm foundation for industrial development and value-adding to many primary mineral products.”^{lxxvi}

That the primary focus for market developers is on availability of reticulation infrastructure is implicit in the discussion concerning the expansion of the

^{lxxv} Price Elasticities of Australian Energy Demand, AGA Research Paper no.3, The Australian Gas Association & ABARE, September 1999, Section 4: Main Results, Section 2: The Role of Gas in Energy Demand, page 15.

^{lxxvi} "Doing business in Western Australia: The Bottom Line", Prospect Magazine, Department of Minerals and Petroleum Resources, Government of Western Australia, March-May 2002, page 18.

domestic gas market in Appendix 6 ("The Development of Gorgon Area Gas"). The point has been more explicitly made in recent statements by the upstream oil and gas industry representative, the Australian Petroleum Production and Exploration Association Limited (APPEA). According to APPEA's Executive Director, Barry Jones;

"Equally, the focus on cheap energy ignores the fact that investors in energy supply need to earn economic returns if increased production is to take place.

Jones said the solution was not more competition in energy use markets, but the timely investment in energy supply.^{lxxvii}

Clearly, to some extent, the delivered price of gas does have the potential to impact the cost structure of mining and minerals processing operations supplied by the GGP. However, the cost of gas transport relative to overall operating costs and other significant factors affecting gross revenues, needs to be given appropriate consideration. Consideration must also be given to the imperative of developing new energy supply infrastructure that is economically sustainable. Similarly, appropriate consideration must also be given to the presumed linkage between what appear to amount to quite small reductions to overall costs of production, and the promotion of competitiveness in the relevant markets.

For convenience, Attachment 4 provides a summary of the detailed analysis of the downstream market provided by Ventnor and included with this application as Appendix 2. What this summary indicates is that, even if the relevant downstream markets are broken down in detail, after consideration is given to both the domestic and international aspects of these markets, the conclusion to be drawn is that neither increased access nor reduced gas transmission prices (if the Code could claim either such potential), would promote competitiveness.

In fact, the conditions for third party rights of access upon terms which are equitable and known in advance, have already been established under the pre-existing State Agreement access regime. The contractual obligations to which GGT has committed under the State Agreement, survive whether or not the Code also applies. Coverage under the Code will do nothing to increase these conditions of access.

More importantly, there is evidence to suggest that the growth of the gas market (to the extent that this serves to promote competition in accordance with criterion (a) of the Code coverage test), is best served by a regime which will promote expansion of gas delivery infrastructure. In this respect, the pre-existing State Agreement access regime has proven its ability to facilitate the development of new pipeline infrastructure and, along with its expansion provisions, represents a superior regulatory option to the Code.

Furthermore, it can be argued that under the Code, the significant countervailing market power which already exists in the hands of the original

^{lxxvii} "Nightmare Looming For Consumers: APPEA", in PESA News, June/July 2002, page 45.

GGT owners who built the pipeline tuned to their own needs, established the tariff path and who now constitute 75% of the GGP customer base, is magnified. The problem with this is the potentially detrimental consequences it may have for accommodating the gas delivery needs of future downstream new entrants (representing competitors to the incumbents in the downstream market) and hence, for the promotion of future downstream competition. As the past president of the Australian Pipeline Industry Association, Mr Mike Lauer put it (with emphasis added):

"Indeed, the only time the transmission pipeline industry seems to see a number of the more vociferous gas end-users is in the regulatory forums. The fact is, that those who use gas transmission pipelines are aggregators/wholesalers, many of whom make up the membership of AGA, and a few very large mining and industrial customers.

The vast majority of gas end users served by gas aggregators have no direct dealings with gas transmission companies, and they may never even have a contract for gas transmission services.^{lxxviii} Yet the new regulatory processes provide those gas end users with a powerful forum in which to exert an inordinate influence over the terms on which gas transmission will take place. Perhaps the level of this influence reflects the fact that the primary role of the regulator of transmission gas pipelines is that of advocate for consumers.

The problem that all this causes for me today is that the gas users we hear from are already serviced with gas, they have access to gas supply infrastructure and they are protecting their own varied self interests.

The development of major new gas pipeline infrastructure is a second order issue for existing gas users.^{lxxix}

To the extent that any regulatory process has the potential to be influenced by existing corporate gas users, it is economically rational that they should wish to "protect their own vested interests". They might do this in a number of ways, including;

- by seeking windfall economic gains (merely transferring profits from the pipeline infrastructure investor to the downstream corporate investor, without having any impact on the degree of competition, or the prospects for enhanced competition in the market), and/or
- by raising the barriers to market entry for their own downstream competitors (by pursuing regulatory outcomes which make the provision of new gas delivery capacity for new entrants more expensive).

Clearly, such outcomes are not in line with the objectives of the Code in regard to promoting competition "in another market". In the context of this application, it is necessary to compare the provisions and effect of the overlapping regulatory processes to which the GGP is subject. Observation of

^{lxxviii} While generally true for other pipelines, the GGP is somewhat unique in the extent to which the majority of the gas it is contracted to deliver is for only a small number of generally large corporate customers, who manage their own gas supply contracts rather than use the services of an intermediary gas aggregator.

^{lxxix} "Major Planned Pipeline Extensions", Presentation by Mike Lauer to the 2001 AGA Convention, 16 November 2001, "The participation of gas users in gas transmission".

regulatory outcomes under the Code, along with a number of statements by regulatory authorities,⁴⁴ indicate that, as the previous quote suggests, the Code embodies a certain user bias. GGT contends that this provides a scope for just such potential influence by incumbent users as discussed above, and that this bias is significantly greater than that which exists under the terms of the rights and obligations associated with the State Agreement. In terms of the coverage test in criterion (a), a clear distinction must be made between the degree of consumer protection afforded by regulation, and the extent to which competition is promoted. By implication, competition is best promoted when new market entrance is facilitated and this requires not only rules for equitable access, but also that the necessary capacity will physically be available to accommodate new entrants. Hence, in terms of ensuring the future promotion of competition, GGT contends that coverage under the Code adds nothing positive to (and possibly otherwise weakens) the terms for third party access that will continue to exist in the event that coverage under the Code is revoked.

Conclusion for Criterion (a)

GGT contends that for the following reasons, coverage under the Code will not provide increased access to the services provided by means of the GGP, nor will coverage promote any increase in the level of competition in any other market, relative to the circumstances that existed prior to coverage:

- (i) that open and non-discriminatory third party access already exists,
- (ii) that sufficient incentive to promote the use of the pipeline already exists,
- (iii) that GGP is not able to significantly influence the market within the relevant markets, and
- (iv) that coverage will not promote the conditions for any increased competition in any other market.

Furthermore, while the GGP is at present subject to a duplication of certain aspects of access regulation, upon removal of coverage under the Code, GGT will continue to meet its contractual third party access obligations under the State Agreement access regime. In this regard it should be recognised that while GGT has been recently forced to remove previously available transportation tariff discounts, it has never increased prices above the levelised tariffs originally established. Under current market conditions, GGT intends to maintain this established tariff as a price ceiling whilst having the flexibility to re-instate market-relevant discounts from time to time when appropriate, in accordance with the objectives of the State Agreement.

Finally, it should be noted that if coverage of the GGP is revoked, and if market circumstances change in the future and recourse to negotiated outcomes or arbitration under the State Agreement fails, users still retain the right to apply to have coverage under the Code re-instated.

CRITERION (B):

"that it would be uneconomic for anyone to develop another pipeline to provide the services provided by means of the pipeline"

The key issue in respect to criterion (b) is the matter of defining exactly what the services are that are provided by the GGP, and hence which services would underwrite the economic viability of developing "another pipeline".

DESCRIPTION OF SERVICE PROVIDED BY GGP

Given the nature of the markets within which context the GGP exists, GGT contends that the service provided by means of the GGP is the transportation of gas for the main purpose of generating electricity as part of an interconnected Western Australian energy transmission network. The extent of this energy transmission network is illustrated in Map 3 of Appendix 1. The extent and distribution of the power generation facilities operated by the State electricity utility alone, is illustrated in Map 6 of Appendix 1.

Except for a small portion (less than 10%) of the total volume of delivered gas, the demand being satisfied by the transmission of gas is the demand for electricity. The vast bulk of the energy market being served is only really concerned about the delivered cost and reliability of the electricity that it consumes. Considerations of social cost notwithstanding, these consumers may have their demand equally satisfied with electricity derived from gas, or by electricity generated from coal or diesel fuel. In the long run, the decision will be an economic one based on the final delivered cost of electricity.

Fundamentally, the role of the GGP within the energy transmission network is the transportation of natural gas from any of Western Australia's upstream gas producers (having access to the state's transmission pipeline network) to downstream users in the Pilbara, Goldfields and Mid-west of the state, for the primary purpose of competing with diesel, LPG and electricity.⁴⁵ In effect, 90-95% of the gas delivered via the GGP actually constitutes unprocessed electricity.

At present, gas is shipped in a southerly direction only, although provision of backhaul services are not excluded. This gas is currently sourced from the offshore Carnarvon Basin and delivered to remote power generators and mine sites in the Pilbara, mid-west and Goldfields regions, as well as to meet the needs of gas and electricity consumers in the vicinity of Kalgoorlie and further south.

Given the provisions that exist for interconnection of the DBNGP and the GGP, as well as the already existing access provisions of both pipelines, the relevant upstream market is virtually the entire existing Western Australian gas production industry. Furthermore, as is illustrated in Attachment 3, the bulk of the state's future

gas reserves will also be accessible to the existing gas transmission pipeline network, with only those reserves contained in the Browse and Bonaparte Basins being, for the present, beyond the reach of the existing infrastructure.

The relevant downstream users are those located reasonably proximate to the pipeline such that the cost of a lateral for interconnection would be a viable investment, having regard to the volume and duration of the user's gas requirements.

Physically, the GGP runs from Yarraloola, where the offshore pipeline from the Harriet gas-gathering hub terminates and in close proximity to the DBNGP, south-east to in the vicinity of Newman and then south to Kalgoorlie. A number of lateral pipeline offtakes connect users to the GGP along its length, as well as a southern lateral extension from Kalgoorlie to Kambalda. A further third party pipeline extension of this lateral to provide gas to Esperance for power generation will soon also be built (see Appendix 7, Media Releases: "Esperance power station gets green light").

This definition might be expressed as a "point-to-point" service, however recognition that the pipeline in fact has existing and/or explicit provisions for potential future intermediate inlet and outlet points along its length makes this description appear somewhat simplistic. Further, the GGP forms a part of what has been described in at least one fairly recent government report as a "developing latticework of natural gas pipelines", facilitating the provision of strategically located competitive energy supply throughout the state.⁴⁶

Hence it may be appropriate to consider criterion (b) in a broader sense than restricting the evaluation to terms merely deriving from competing pipeline routes. Too narrow an interpretation of the "services" referred to in criterion (b) would imply that a gas pipeline is always a monopoly unless another gas pipeline were to exist, running physically parallel to it and interconnecting with it (or being practicably capable of interconnecting with it) at any point along its length. In fact, as already discussed in earlier sections of this application, the GGP transports gas for the purpose of competing primarily in an electricity market. In this sense, the GGP faces direct competition from alternative energy sources which parallel and interconnect with the pipeline and/or its existing and potential customer base, throughout the length of the pipeline.

Therefore, in terms of the service which the GGP affords, GGT contends that adequate consideration needs to be given to the GGP's role in;

- (i) the provision of competitive, alternative energy to meet the needs of the downstream market, and,
- (ii) the facilitation of supply of fuel-on-fuel competition in the Pilbara, Goldfields and Mid-west electricity markets, as well as,
- (iii) the supply of a gas transmission service from Yarraloola and other inlet points located anywhere proximate to the Western Australian transmission pipeline network, to Kalgoorlie and other outlet points, potentially located anywhere along the GGP.

The primary service provided by GGT is solely related to the business of transporting gas, and GGT is not involved in the trading or purchasing of gas.

It should also be noted that the GGP also provides a number of other services, which are of the nature of demand management services. These services are only such as might normally be associated with the provision of a gas transmission service in order to facilitate smooth operation for both the pipeline operator and the gas shipper. It has been noted that, "since the start of the GGT pipeline, other services (Interruptible Service, Parking Service and Authorised Imbalance Service) have been offered."⁴⁷ Beyond the explicit understanding that the provision of these services are not threatened in any way by the prospect of revocation, specific consideration of these services does not seem to be warranted for the purpose of this application.

GROUNDS FOR REVOCATION UNDER CRITERION (B)

Demonstrably, GGT has historically sought to meet the relevant needs of pipeline users. The State Agreement and the Code both have a requirement to establish a reference service as a base line for open access, with the provision of other, individually tailored and thus negotiated, non-reference (but nonetheless, available) services. It should be understood unequivocally, that these demand management services continue to be offered and available for GGP, whether or not the pipeline remains covered under the current overlapping regulatory regime.

The construction of the GGP was undertaken as a result of competitive market forces and in circumstances that were subject to fully competitive evaluation and selection, as has been discussed earlier in this application. (Also refer to Attachment 1 for a concise chronology of the development of the pipeline).

Upon completion, the GGP displaced a substantial volume (but not all) of the electricity which had formerly been supplied by high voltage transmission line to Kalgoorlie from Western Power generation capacity linked to the SWIS.^{lxxx} This capacity, along with the presence of diesel fuel for power generation (and other uses) continues to exist as a direct competitive force. As a consequence, the GGP does not enjoy unconstrained monopoly power within the markets that it serves. In addition, public statements as to the viability of a pipeline which could bypass the GGP and meet potential gas demand in excess of that capable of being met by the GGP (due to its physical design constraints) have been supported by recent government activities to facilitate such a development. The wider social and economic benefits that resulted from the development of the GGP continue to be expanded upon by the development of the energy transmission network as a result of existing market forces, which have nothing to do with the introduction of the Code.

^{lxxx} The inappropriateness of assuming that the coverage test in criterion (b) should be confined to considering only like forms of infrastructure (ie. a pipeline can only compete with a pipeline, or indeed an electricity transmission line can only compete with another electricity transmission line) is highlighted in this real world example of a gas pipeline being "developed to provide the services" of an electricity transmission line.

GGT contends that for these reasons, discussed in the following sections, criterion (b) is not satisfied.

(i) Past and continuing history of competitive development.

The history of the development of the GGP is discussed in considerable detail in the Background section (f) of this application as well as in Attachment 1. Additional detail is provided in Appendix 2 (Goldfields Gas Pipeline: Relevant Downstream Market).

The case for the competitive basis upon which the GGP was developed is well made in these sections of this application and will therefore not be repeated here. What is apparent from a review of the history of the GGP is that the nature of the environment in which it was developed, had and continues to have a focus on competition for the supply of energy. In this context, GGP has been widely recognised (as evidenced by the wide variety of references cited previously in this application) to be faced with direct competition from electricity, diesel and LPG gas. This was true from the inception of the pipeline, and continues to be so.

As we have discussed previously in this application, the GGP displaced approximately 140MW of reticulated electricity in Kalgoorlie, and almost 300 million litres per annum of diesel fuel used in power generation in remote, stand-alone sites. This alternative capacity to supply electricity continues to exist and, as we have seen in the discussion in regard to criterion (a), diesel continues to actively win market share over gas-fired power generation.

Furthermore, perceptions of future energy demand driven by resource development and recognition within the downstream industry that existing infrastructure has only a limited ability to meet future needs, has led to new pipeline and power generation proposals. Such industry initiatives will lead to even greater interconnection of the existing network, and expanded competitive energy options. While such market responsiveness in regard to the development of socially beneficial infrastructure is desirable,⁴⁸ it will expose GGP to increasing competitive pressure. To some extent it might be argued that it is perceptions of the presence of temporary market power associated with the GGP, which has invited new entrants. This is debatable, and in any event, is no indication of an inefficiently operating market.⁴⁹ Further, GGT maintains that it has already demonstrated (in the discussion regarding criterion (a)), that the GGP, for all practical purposes, does not have and has not had, any significant ability to influence the markets which might be identified as its dependent markets.

GGT acknowledges the Productivity Commission's opinion that;

"In the Commission's view, the current state of case law has not established that there is a significant risk that facility services with natural monopoly characteristics

but little market power, on account of the existence of substitute services, will be declared.^{lxxxix}

Nonetheless, it must be recognised that, as a consequence of the coverage criteria having never previously being tested in regard to the GGP, it is currently covered by the Code. That is, it has in effect been "declared" (or the equivalent thereof) despite the clear existence of substitute services and a demonstrable lack of market power in the relevant markets.

The status of the markets relevant to this application might best be described as being "workably competitive".⁵⁰ The competition which exists in these markets is not static in the long term, nor perhaps has it achieved a "theoretically ideal" level of efficiency. However, this is not a requirement of the tests for coverage, either explicitly or in the guiding principles upon which the application of the Code is predicated,⁵¹ as set out in both the Act and the Introduction to the Code.⁵²

The relevant authorities within the Government of Western Australia do not contest that this competitive state of affairs exists within at least parts of the state's transmission energy network. A recent joint submission from the Department of Treasury, the Office of Energy and the Department of Resources Development (since renamed) is cited by the Regulator in his Draft Decision concerning the GGP. These departments make the observations that "pipeline on pipeline competition exists for a number of pipeline systems" and that "the transmission pipelines supplying the South West of the state are facing competition from LPG and electricity."⁵³

The point which GGT contends is relevant to this application is that the circumstances which make it economic to develop an alternative delivery of the service provided by the GGP exist by virtue of the competitive environment in which the pipeline was originally developed and within which it continues to compete.

(ii) Currently economic to develop another pipeline to provide the services provided by means of the GGP.

As has been shown, the Western Australian energy market is serviced by a network of gas transmission pipelines as well as an electricity transmission network that include a number of extended transmission corridors. Such forms of energy supply require a certain economy of scale before investment in such expensive infrastructure becomes viable. Thus an adequate base load of demand must exist or be reasonably anticipated in order to justify initial investment in capital intensive infrastructure. In regional Western Australia, there is of course an existing statewide road and rail distribution network delivering diesel fuel and bottled LPG gas that provides a highly effective platform for initial regional development, especially remote small-scale

^{lxxxix} Productivity Commission, Review of the National Access Regime, Report No.17, 28 September 2001, page 191.

projects. This was evidenced in a recent announcement by the State's Energy Minister, stating (with emphasis added);

"...StateWest Power would build small scale diesel fired power stations supplying Meekatharra, Cue, Yalgoo, Wiluna and Sandstone. Natural gas or LPG would substitute for diesel when economical, generating added environmental benefits."^{lxxxii}

Once an adequate initial base load of energy demand is established, it becomes possible for a subsequent extension of the transmission network supplying electricity and/or gas, to compete.

Western Australia is rich in primary resources. As long as commodity demand exists, resources companies will continue to evaluate the profitability of developing those resources. Government of course also has a role in providing an environment that encourages this development (with all its attendant social and economic benefits), and balancing the public interest in terms of maximising royalties from the extraction of public goods, as well as maintaining environmental and social standards.

Establishing an environment conducive to development includes providing potential new developers with equitable access to existing infrastructure. This goes to the heart of the development of the Code. However, it is the commercial imperative which lives on in the *raison d'être* of profit-seeking resource companies which will ensure that new developments, including pipelines, will continue to be proposed and pursued. This will only occur for so long as development proponents believe that their investments will be profitable. For an investor, this requirement for investment to be profitable, whatever the degree of competition it faces, is what is meant by the expression, "economic to develop".

In keeping with this 'commercial' interpretation of "economic to develop", the Regulator in his Draft Decision for the GGP, has considered proposals for further expansions to the existing gas transmission pipeline network which will compete with the service provided by the GGP (emphasis added):

"The Access Arrangement Information provides detailed discussion by GGT on the amount of competition faced by the Goldfields Gas Pipeline, from both other fuels and other pipelines. It is noted that lateral pipelines from the Dampier to Bunbury Natural Gas Pipelines (DBNGP) could compete with the pipeline. Examples include the Midwest Pipeline, which services vanadium processing at Windimurra and a pipeline from Geraldton to Mount Margaret currently under consideration by Anaconda.

The Midwest Pipeline could be extended to compete directly with the Goldfields Gas Pipeline. However, because of the small diameter of the Midwest Pipeline (200/150 mm) this would require a high degree of compression to meet loads such as those being sought to supply mining and mineral processing projects at Murrin Murrin and Mt Margaret. The additional compression and extension of the Midwest Pipeline

^{lxxxii} Media Release, "StateWest Power to supply Mid-West towns", Hon. E. Ripper, Deputy Premier, Treasurer, Minister for Energy, 7 September 2001. (Also see Appendix 7 to this application).

from Windimurra to Murrin Murrin and Mt Margaret may be uneconomic in current circumstances.

In regard to the proposed Geraldton to Mount Margaret Pipeline, such a development may be economic at the current Goldfields Gas Pipeline tariff.^{lxxxiii}

In another Draft Decision, the Regulator cites the operator of the DBNGP as being of the view that;

“Epic Energy believes a more economic and flexible approach [to the interconnection of the DBNGP and the GGP at the latter's northern end] is by the creation of a new lateral through the Mid West linking the two pipelines.”^{lxxxiv}

In fact, a substantial body of work has already been undertaken on just such a proposal (i.e. the GEMM pipeline), with pipeline licences covering two alternate routes⁵⁴ having already been issued to the proponent.⁵⁵

The release of the Regulator's Draft Decisions on the DBNGP and the GGP in mid-2001 introduced a number of new aspects of uncertainty which demand consideration by all proponents of infrastructure investment. For the proponent of the GEMM pipeline however, the impacts of these regulatory decisions at the time did not alter its view as to the viability of the GEMM pipeline, which it considered would, with a suitable base load, still proceed.⁵⁶

This initiative has also received active and practical support on the part of the State Government, which has already initiated the establishment of a 450 metre wide access corridor in order to facilitate the pipeline (as well as other potential infrastructure). The initial environmental, geotechnical and Aboriginal heritage studies and surveys for this corridor – the essential first practical steps to construction - are due for completion at the end of 2002.⁵⁷

It needs to be recognised that the promotion of gas utilisation, with its consequential benefits for competitive resource development and the realisation of social and economic benefits, is best served by the continued expansion of pipeline infrastructure. This is clearly demonstrated in the discussion relating to criterion (a) in this application. It is a sentiment frequently advocated in various proposals by the State Government, GGP's customers and regional project developers. In so far as they relate to gas pipelines, the focus of such proposals is clearly the intended development of financially viable projects to facilitate the supply of competitive energy⁵⁸ (reinforcing the point that has previously been made, that the relevant downstream market is the market for energy).

It must be noted that the proponents of the current GEMM proposal have recently announced a deferment of these plans. However, GGT understands that this decision arises primarily from considerations associated with the

lxxxiii Draft Decision: Access Arrangement: Goldfields Gas Pipeline, Independent Gas Pipelines Access Regulator, Western Australia, 10 April 2001, section 5.4.3.9, page B-108.

lxxxiv Epic Energy Submission 9, in Draft Decision: Proposed Access Arrangement: Dampier to Bunbury Natural Gas Pipeline, Independent Gas Pipelines Access Regulator, Western Australia, 21 June 2001, section 7.3, page B-317.

company's financial position and is not aware of any statements or other evidence to indicate that the economic rationale underlying the proposal is fundamentally altered by this announcement.

Rather, what has been demonstrated in the GEMM pipeline proposal is that as gas demand grows, additional infrastructure is going to be required, both in order to capture the new economies of scale which will become available, as well as to satisfy the market demand once the maximum capacity of the GGT is exceeded. The key issue becomes one of the timing of the future growth in market demand. This then becomes a matter of prediction. While any such prediction is going to be both subjective in nature and dependent upon the level of confidence attached to the specific forecast and required of it, the Regulator, in his Draft Decision on the proposed GGP Access Arrangement, has made the following observations:

"The above submissions from interested parties [representing State Government Departments, politicians, and upstream and downstream customers] express considerable optimism about the future demand for gas transmission services for the Goldfields Gas Pipeline. These views are in contrast to the subdued outlook by GGT as illustrated in its graph shown in Appendix C of its Access Arrangement Information and reproduced in Figure 1 above.^{lxxxv} GGT's assumption relating to the renewal of existing contracts also needs to be considered in the light of possible existing options to extend contract terms beyond 2016.

GGT's forecast throughput for the Goldfields Gas Pipeline has been compared with another forecast by Australian Pipelines Limited (APL). The APL forecast was made public in a prospectus relating to the offering of units in the Australian Pipeline Trust, which included a share of the Goldfields Gas Pipeline assets. This prospectus was issued on 5 May 2000 and indicates a substantially higher throughput forecast than that projected by GGT, particularly after the end of the proposed Access Arrangement Period...."^{lxxxvi}

It is also possible that a new GEMM-like proposal based upon the economies of scale in delivering gas further south than the Mid-West could just as easily crystallise, if the market develops in such a way that the geographical distribution of demand dictates it. What this demonstrates is market forces at work.

As has previously been identified, once an initial market is established, and sufficient demand develops, it becomes viable to invest in more capital intensive but also, because of improved economies of scale, more efficient forms of energy supply. Given that the demand for energy in the relevant market is, in this case, actually a demand for electricity, it follows a more or less natural evolution of the market that the small scale diesel fuelled power stations will gradually give way to larger scale, cheaper to run, gas fired power plant. If this market grows sufficiently, then initial gas transmission pipeline

^{lxxxv} These divergent views may be evidence of the subjective nature of forecasting. In addition, there is a need to recognise the requirement to match the degree of confidence in the forecast with the appropriate level of investment risk recognised by Regulator's under the Code, for which purpose the forecast in the proposed Access Arrangement was produced.

^{lxxxvi} Draft Decision: Access Arrangement: Goldfields gas Pipeline, Independent Gas Pipelines Access Regulator, Western Australia, 10 April 2001, section 5.3.2, page B-87.

capacity will be exceeded and new investment will be required for additional capacity. Depending upon the extent of this growth in demand, and the optimism (or far-sightedness) with which the future potential for growth is viewed, it is reasonable to think that later infrastructure investments will be in a position to enjoy much greater economies of scale than the initial market entrants.

It is critical to realise that it is on the strength of just this claim to greater economies of scale that the proponents of the GEMM pipeline can claim to offer the competitively priced gas transportation tariffs which have been cited. To understand this, it is necessary to firstly consider the relative sizes and capacities of the pipelines in question. The following table compares the size and cost (in comparable, "current value" terms) of the pipelines relevant to this application.

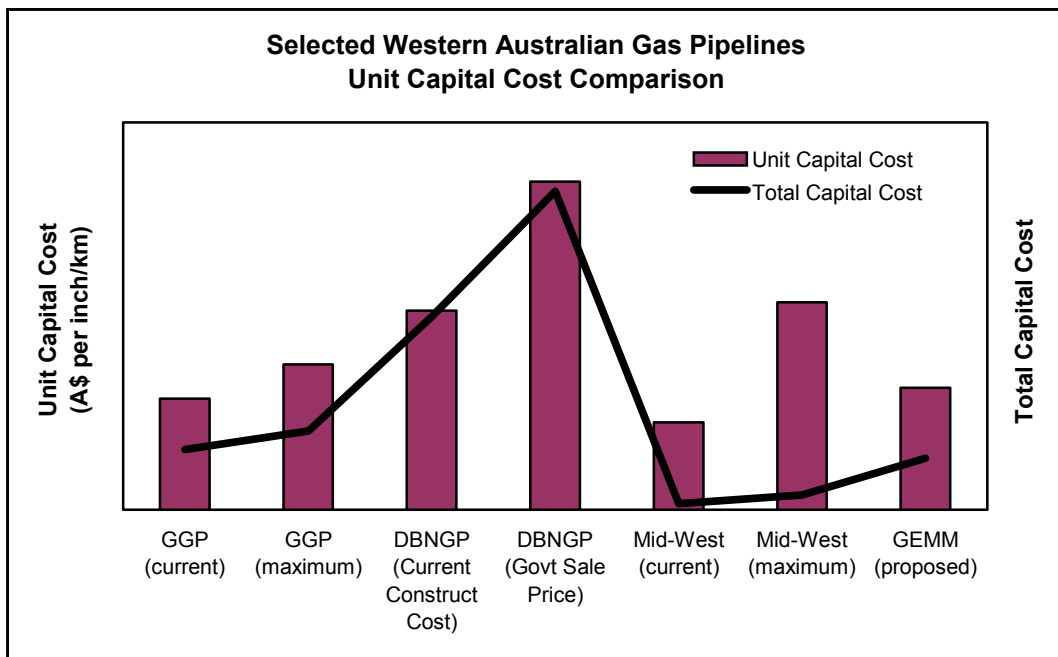
Table 7: Selected W.A. Gas Pipelines Compared

Pipeline	Length	Average Diameter	Capacity	"Current" Build Cost	notes
DBNGP	1399 km	26"	600 TJ/d	A\$1,495m	1
GGT	1378 km	14.8"	100 TJ/d	A\$466m	2
Mid-West	350 km	7.6"	20 TJ/d	A\$48m	3
GEMM	790 km	20"	306 TJ/d	A\$398m	4

- Notes: 1. ref. DBNGP Draft Decision, OffGAR, June 2001.
 2. ref. Updated GGT data (includes Wiluna compressor station)
 3. ref. APT Prospectus, May 2000
 4. ref. "Kick-starting The New Millenium, Developing the Goldfields and Mid-West", Anaconda, December 1999.

Based on publicly available data, the following graph illustrates the relative unit costs of construction associated with these disparate pipelines.

Figure 4.



It can be seen from Figure 4 that the GGP, being a smaller size pipeline than the DBNGP but similar in length, compares favourably on the basis of unit construction cost. This may be largely explained by the fact that the GGP involves physically less steel than the DBNGP and, the pipe diameter being smaller, more linear metres can be transported per load delivered for installation. The Mid-West pipeline, despite being shorter than either the DBNGP or the GGP (and hence enjoying some diminished economy of scale in installation cost), is smaller and had the significant cost advantage of already existing road access, and so enjoyed a lower unit construction cost. The proposed GEMM pipeline, while being shorter than the GGP, has a larger size and hence its unit construction cost is no cheaper than the GGP.

However, this preceding comparison does not provide any insight into the economies of scale inherent in pipeline sizing. This is better illustrated in Figure 5, below, which shows another view of unit cost, this time taking into account both pipeline capacity as well as length.

Figure 5.

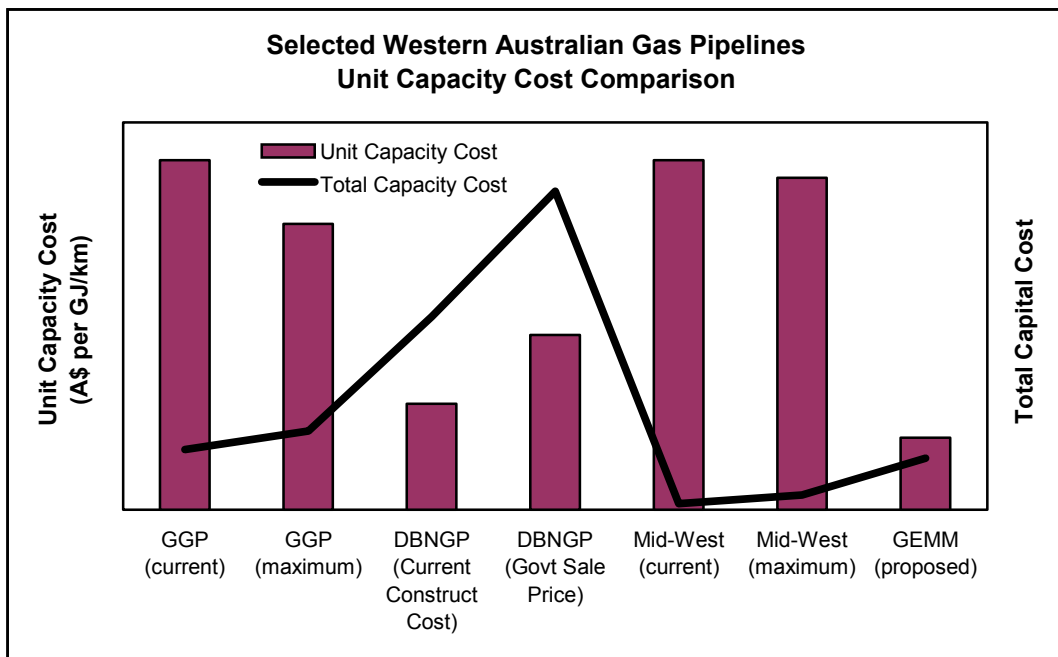


Figure 5 clearly illustrates the basis for claims that it is possible for a new pipeline to provide the gas delivery service to the Goldfields that the GGP currently provides, at a lower tariff. Quite simply, for the same unit capital cost, a bigger capacity pipeline can carry more units of gas and hence, needs to charge less per unit in order to achieve the same return on investment.

The preceding discussion clearly illustrates that the GGP is faced (either now or in the future) with the very real prospect of direct pipeline on pipeline competition for at least a good part of its load. The fact is that the proponents (both private sector and within government) of at least one such proposal for a competing pipeline are both well advanced in their planning and continue to advocate the commercial viability (under the appropriate demand scenario), as well as the social and economic merits of that proposed alternate pipeline.

Furthermore, it needs to be recognised that the test in criterion (b) as to whether it is economic to duplicate the services provided by the pipeline, is fundamentally a test for natural monopoly characteristics. Too narrow an emphasis on service duplication by means of pipelines only would distort the conclusions drawn by overlooking the extent to which GGP directly competes with alternate energy forms. The evidence suggests that the GGP displays none of the characteristics of monopoly hold over its prospective customers, who also have recourse to electricity supplied via transmission line or stand alone power generation fuelled by diesel delivered via the state's extensive road network.

It is important to consider that the expansion of the service provided by the GGP can also be, and in practice often is, met by alternate means of delivering that same service via road or electrical transmission line. Both of these substitute technologies are means of delivering the same end product as the GGP. Moreover they clearly enjoy spare capacity and frequently other

operational advantages, as well as often having favourable financial economics. All of these factors mean that these alternatives for providing the service provided by the GGP must be considered as being currently economic to develop within the context of criterion (b).

These alternative technological means of delivering the same service as is delivered by the GGP must be considered for the intellectual analysis of the test in criterion (b) to be considered robust. This has been identified in the Productivity Commission's Review of the National Access Regime:

"As regards criterion (b) [...a proposed change to the wording of the criterion with...] reference to a 'second facility' could (wrongly) be interpreted as referring to a service based on the same technology."^{lxxxvii}

Alternative technologies - that is technologies for delivering energy to the downstream energy consumers who constitute the GGP's dependent market - must be taken into account in considering not only the "economic to provide the same services provided by means of the pipeline" question, but also the extent to which the GGP truly exhibits natural monopoly characteristics.

(iii) Pipeline infrastructure development has already realised social benefits with continuing potential for future benefits.

It has been demonstrated in the preceding section, that it is economic in financial terms to develop another pipeline (as well as alternate technologies) to provide the services provided by means of the GGP. It should be recognised that the development of the GGP itself, has already introduced substantial efficiency benefits to the relevant market, with continued potential for further future benefits yet to be realised. Nonetheless, because the design of the GGP was "tuned" to the demand which existed to underscore its construction at the time, as well as the future potential demand then foreseeable, it has an inherent limitation in terms of its physical size and realisable economy of scale. A new pipeline, building upon the market established by the GGP, has the potential to realise even greater efficiencies in transmission cost and hence develop broader benefits. As one regional development proponent has put it, "development of additional regional infrastructure ... is critical to deliver significant economic and social benefits equally for the bush and all Australians".⁵⁹

Previous sections of this application have already discussed the nature of the social and economic benefits which the construction of the GGP was expected to yield. Certainly the economic benefits were clear, as the following discourse reveals.

"The gas price of \$2 per gigajoule from the Pilbara, with the delivery cost to the goldfields gas pipeline to Newman would be about \$3.57 per Gj [sic]. As Hon Mark Nevill said, the price at Kalgoorlie it will be \$5.67 per Gj. This compares to \$8 or \$9

^{lxxxvii} Productivity Commission, Review of the National Access Regime, Report No.17, 28 September 2001, page 191.

per GJ for the distillate, which price is net of the diesel fuel rebate. If one looks at the prices at Newman - \$3.57 delivered compared to \$8 or \$9 per GJ for distillate - it is a saving of 60 per cent.^{lxxxviii}

It cannot be questioned that these economic expectations have since been realised. This is an historical fact. Further there were other consequential benefits from the introduction of the GGP. For instance, it made possible gas reticulation in Kalgoorlie, where the retail price of LPG had previously been approximately \$24/GJ. Following the supply of natural gas from the GGP, the State gas distributor began to provide natural gas in Kalgoorlie for \$16/GJ. Even though gas transportation discounts have not to date been passed through to distribution customers, natural gas continues to be supplied at substantially lower prices than the bottled LPG alternative.^{lxxxix}

However, GGT notes the views expressed by the Tribunal in the EGP Decision that;

"in deciding whether it is "uneconomic" for a person other than the provider of the existing pipeline to develop another pipeline, the enquiry is not limited to a narrow accounting view of "uneconomic", or simply issues of profitability. Rather "uneconomic" is to be construed in a broader social cost benefit sense, in which the total costs and benefits of developing another facility are brought into account."^{xc}

In considering the nature of social efficiency and the need to avoid "socially undesirable outcomes", the Tribunal also cites and in its ruling, gives consideration to evidence provided in the EGP case by the applicant's expert economist, Dr Ergas regarding the three dimensions of "efficiency".^{xcii} These are identified as productive efficiency (i.e. production at least cost), allocative efficiency (i.e. allocation of services to those who value them most highly) and dynamic efficiency (i.e. the preservation of incentives for innovation and efficient investment).

The GGP, developed as it was under the principles enshrined in the State Agreement, clearly fulfils each of these aspects of efficiency.

The pipeline was not only competitively tendered, it was ultimately built by a consortium of energy consumers who would be the pipeline's own main customer base. Hence every incentive existed for the owners to avoid any undue expenditure and to minimise the construction cost, while not compromising on future operability. GGT itself, is an operating management

^{lxxxviii} Hon N.F.Moore, Hansard, 17 October 1996, page 6736.

^{lxxxix} Based on current prices supplied by Kleenheat Gas and AlintaGas, a domestic gas customer in Kalgoorlie who consumes 18 GJ of gas per year would pay an average price of \$30.91/GJ for LPG or \$21.15/GJ for reticulated natural gas. (For LPG, assumes one 45kg LPG cylinder represents 2,268 MJ, cost per cylinder is \$59.64, delivery charge is \$6.45, with annual rental charge of \$38.50, per Kleenheat prices quoted in August 2002. Reticulated gas cost based on an Energy Charge of \$0.0604/unit, assuming 3.6 MJ energy equivalent per unit, with Supply Charge of \$0.2174/day, per AlintaGas prices as at 1 July 2002.)

^{xc} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, , page 15.

^{xcii} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, , page 17.

entity which passes - in full - the cost of its own activities on to its joint venture owners and hence is required to minimise the extent to which it acts as a drain on the bottom line profit. Hence the incentive existed (and continues to exist) for the GGP to provide the service it provides at least cost from the outset. Thus the criterion of productive efficiency is satisfied.

As has been shown, the GGP is currently effectively operating at full utilisation for its current configuration. However, GGT has (under the previous access regime) sought to market its additional developable capacity at marginal prices in order to promote market development. Discounted tariffs offered at the time of construction and subsequent promotions of available spare capacity in the pipeline have seen, and continue to see, the rationale underlying the criterion of allocative efficiency be satisfied.

The GGP was constructed to optimally suit the demand which existed for the service it would provide and for the future growth in that demand, then foreseeable. This was tested in the market prior to the pipeline design being finalised. Additional third party loads were actively sought from inception, with the intention of capturing the maximum realisable economy of scale. (See article in Appendix 5, "Search for New Customers"). At the time of construction and for the foreseeable future in 1995/96, the investment in the GGP was efficient, based on both the route selected and optimised initial and developable capacity. The theoretical criterion of dynamic efficiency was then and since satisfied to the maximum extent practicably possible. This arises as a consequence of the initial excess developable capacity requirements agreed under the terms of the State Agreement, as well as the continued availability of this incremental capacity at diminishing marginal cost.

While it may be socially desirable (in an efficiency sense) to fully utilise existing infrastructure, it also becomes necessary to consider the wider social impacts that will result from the development of another pipeline replicating the services offered by the GGP. The reality is that the GGP can service all demand within its feasible catchment area up to a finite limit. This limit was set at the design stage, based on what was envisaged as being an adequate balance between current expenditure and future utilisation at the time the pipeline was built. Within this demand scenario, additional capacity is provided at the lowest feasible marginal cost, therefore it might be argued that it is inefficient to duplicate the service potential of the GGP up to this limit.

However, for the market projections that have been proposed by more aggressive resource developers, the GGP does not ultimately have sufficient developable capacity to meet the levels of demand now envisaged. In this context, it can be seen that the eventual introduction of a competing, larger scale pipeline is likely to be an intrinsic element of the next quantum step in the development of the regional market. From this perspective, the potential for bypassing the GGP cannot be seen as socially "undesirable" in the sense of productive, allocative and dynamic efficiency.

The development of another pipeline route (i.e. via the DBNGP and the Mid-west or GEMM pipeline) with the capacity to substantially replicate the

services already provided by means of the GGP will bring with it, among other societal advantages;

- social benefits in terms of providing greater access to an expanded downstream Goldfields market for Western Australian gas producers;
- additional options for users for the competitive supply of gas;
- geographical and temporal security of supply; and
- potential to facilitate the development of additional upstream gas supply projects because, as the evidence suggests, it is the growth of the infrastructure network which primarily promotes market demand.

In terms of dynamic efficiency, the development of this "other pipeline" will build upon the natural gas market already established in Western Australia. The consequential opportunities for investment, innovation and development of markets upstream and downstream of gas transmission have already been substantial and will continue to be so.

In terms of allocative efficiency, the development of increased access between suppliers and consumers, the expansion of markets and commercial options, and the augmentation of already existing competitive supply options must be seen as positive contributions.

As has been demonstrated, it is the expanding availability of equitable access to gas supply (and not downward pressure on the price of gas paid by the existing customer base) which will promote competition in the gas market. GGT contends that the Code in no way facilitates such expansion, particularly relative to the provisions of the pre-existing State Agreement. Moreover, recent proposals for network expansion in Western Australia have been completely independent of any positive effects that might be attributable to the introduction of the Code.

(iv) The GGP does not enjoy unconstrained monopoly power or barriers to entry.

Notwithstanding regulatory precedent which addresses interpretations of the specific words within the criterion (b) coverage test (e.g. meaning of "access", "services", "develop", "uneconomic", etc.), it should be recalled that the real matter being tested under criterion (b) is whether or not the services provided by the pipeline in question convey a substantial degree of monopoly power within the appropriate market and hence should therefore be subject to regulatory control.

A monopolist can be identified as having the following characteristics:

- * By definition, it is either the only firm in the market or it holds overwhelming dominance in that market,
- * It is protected from competition by barriers to entry,

- * There are no close substitutes for the goods or services that it provides, and,
- * It typically enjoys diminishing marginal costs (i.e. economies of scale).

The following discussion clearly illustrates that the first three of these characteristics do not exist in the case of the GGP, and that the fourth is mitigated by the relevant provisions of the contractual obligations which exist in the absence of the Code, as determined by the State Agreement.

As has been discussed, the primary service which is provided by the GGP, is the delivery of gas for power generation, from the upstream source of that fuel, to the various locations of the downstream energy consumers. That is, the provision of a competitive, alternative energy source (indirectly, the supply of electricity) to diesel, LPG and electricity from the SWIS.

Hence, while the GGP is for the time being the sole supplier of natural gas into the markets in which it has direct reach, it quite clearly faces competition within that market.^{xcii} This situation imposes a substantial market constraint on the exercise of any monopoly power that might otherwise be inferred. As pointed out recently by the Chairman of the Productivity Commission;

“...the availability of substitutes limits the exercise of market power. For example, rail track providers may be sole suppliers but, for most freight or other services, they face intense competition from other transport modes, notably road.”⁶⁰

For the GGP, the spare capacity and ready availability of electricity from the SWIS, and the ubiquitous presence of easily stored diesel, provide evidence of competitive substitutes for gas and indicate low barriers to competitive entry in the market for generation fuel.

Furthermore, gas fired power stations owned by others and located in the north west of the state, have been able to competitively transmit electricity via transmission lines to mine sites located in the vicinity of the GGP in the Pilbara region. Mines at both Paraburdoo and more recently, West Angelas, despite being sites of substantial energy consumption and within the apparent GGP catchment range, are supplied by electrical transmission.

Clearly "close substitutes" for the services provided by means of the GGP do exist. In fact, it was for the purpose of introducing a "close substitute" as an alternative to the pre-existing LPG and diesel fuelled or reticulated electricity which had traditionally serviced the region, that the GGP was built. Obviously, the GGP has not and does not enjoy the protection from competition provided by barriers to entry into the energy market or through

^{xcii} It should be noted that the proponent of the proposed Telfer mine site power station has applied to the Western Australian State Government for a pipeline licence to construct and operate a pipeline which will supply natural gas from the Pilbara Energy Pipeline at Boodarie, Port Hedland ("Notice of Application for a Pipeline Licence", West Australian Newspaper, Public Notices, 31 October 2002) rather than obtaining gas via the GGP, even though the latter has an apparent geographical advantage at Newman.

any form of franchise, such as might be associated with a traditional government utility.

The GGP, being the product of private enterprise from its inception, has never had either the protective franchise or the commercial incentive to withhold access to the services which it offers. The pipeline has a demonstrable history of open access to third parties.

As discussed in a previous section of this application, the capacity of the GGP, despite being currently close to full utilisation, can be expanded at lower incremental cost, at least up to the limit of maximum compression. Beyond this, capacity expansion can only be achieved by expensive looping, however the amount of additional capacity which can be achieved before this quantum step in the capacity cost function is reached, equates to a capacity increase of approximately 60% of existing capacity.

Clearly, GGT is not the only firm competing for a share of the energy market which it services. In fact it enjoys only a minor share of the upstream market which it serves. Hence it is clear that GGT does not enjoy any element of "overwhelming dominance" in the relevant markets.

Another attribute of monopoly power, is the ability to sustainably increase prices. While GGT has recently found it necessary to remove price discounts previously available under the State Agreement access regime, it should be noted that it has never increased prices above the levelised price originally established. This levelised tariff continues to rely upon future load growth in order to subsidise present returns. In reality, the cost of gas delivered via the GGP has a price ceiling established by the alternate net cost of other fuels.

This price ceiling is not a simple comparison of the delivered cost of the fuel, but involves evaluating the net-back opportunity cost of the energy options, after accounting for capital costs (lateral pipelines, more expensive gas turbines versus lower cost diesel generators, costs of conversion and backup contingencies, etc), the time available in which the investment must "pay-out", as well as ongoing operating costs. Furthermore, because of the requirement for an equitable and transparent transportation tariff, the price which can be charged for delivery at intermediate points along the pipeline, is largely determined by the opportunity cost of the remotest (most southerly, in this case) user. As the Kalgoorlie gas market is primarily a market for power generation competing with the inter-connected SWIS, it can be seen that there is very real competitive pressure limiting the tariff to all users along the pipeline.

The corollary of this is that GGT also faces a floor price determined by the need to provide a required return of and on capital (including the incremental expenditure which would normally be required to facilitate gas deliveries to each individual user). It is a unique characteristic of the market in which GGT competes, that all too often, the price ceiling established in that market is lower than the price floor at which gas can viably compete.

Thus, to quote the Chairman of the Productivity Commission once more, *“there will not always be an incentive or the scope to exploit market power, even where it appears to exist”*.^{xciii}

In summary, it is apparent that the service provided by the GGP does not have the characteristics that would indicate that it has an ability to exercise any significant degree of monopoly power. The effect of energy competition (as well as the pre-existing and continuing obligations of the State Agreement) means that the GGP is substantially constrained in any attempts it might make to exercise a significant monopoly control over the market. Consequently, in the sense that criterion (b) is a test as to whether the pipeline should be covered because it is able to extract unconstrained monopoly rents from the market, it fails to satisfy the criterion.

Conclusion for Criterion (b)

GGT contends that for the following reasons, coverage under the Code is not warranted for the GGP in that it is economic in both the conventional economic sense, as well as a social context, for another pipeline (and/or other energy transmission medium) to be developed to provide the services currently provided by the GGP.

- (i) Historical and continuing evidence of competitive development,
 - (ii) Current evidence that it is economic to develop another pipeline,
 - (iii) That development has already and continues to offer social benefits,
 - (iv) The GGP does not enjoy unconstrained monopoly power or barriers to entry.
-

^{xciii} Presentation: The ‘baby and the bath water’: avoiding efficiency mishaps in regulating monopoly infrastructure, Gary Banks, Chairman, Productivity Commission, 5 July 2002, page 5.

CRITERION (C):

"that access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety"

GGT takes its responsibilities in regard to health and safety seriously and does not wish to compromise its own reputation in this respect by entering into dispute over criterion (c) of the Code. However, for the record, GGT does wish to make the following observations in respect to this aspect of coverage.

Given the imperative nature of the maintenance of safe and reliable operations in regard to the transmission and distribution of natural gas, any incentive towards compromising essential maintenance and hence, safety, should be considered an "undue" risk.

For the purposes of considering criterion (c) it is clear that the term, "access", is intended to mean "access as provided by coverage under the Code", as opposed to, in this instance, access provided under the terms of a different, pre-existing access regime (i.e. the State Agreement). Under the State Agreement access regime which pre-exists the introduction of the Code, third party access to the GGP was available on a commercial basis that factored in a rate of return on the investment which was commercially acceptable within the relevant industry sector.

However, many industry commentators have expressed the view that the application of the Code gives rise to the prospect of regulatory error, the imposition of unproven and indeed flawed economic incentives and as a consequence, involves an inherent degree of risk. This is a risk that is shared by both infrastructure investors and the wider social economy. In the words of the Chairman of the ACCC;

"If tariffs on pipeline access are set too high, there is a direct transfer of wealth from consumers to the asset owners; if too low, the asset will not be maintained and investment plans will be dropped."^{xciV}

Unfortunately, the magnitude of the consequences of this regulatory risk is not symmetrical. Safety must not be compromised for the sake of short term, sectarian gains. For its part, GGT remains absolutely committed to the maintenance of the highest standards of human health and safety in the course of its ongoing operational philosophy.

Nonetheless, in the context of criterion (c), the long term results which ensue, or seem likely to ensue, from the application of the Code must be weighed against the conditions which demonstrably prevailed under the proven and pre-existing contractual obligations of the State Agreement in governing third party access.

^{xciV} Allan Fels, BRW, June 20-26 2002, page 26.

CRITERION (D):

“that access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest”

GGT contends that to the extent that "access (or increased access)" in practical terms means "additional rights of access provided by the Code which did not exist in practical terms, prior to the application of the Code", criterion (d) is not satisfied in respect to the GGP. It is apparent that the Code provides no additional rights of access for third party access seekers that did not previously exist. If anything, the Code erodes certain user benefits in regard to the manner in which it constrains Service Provider's ability to apply funds to extensions, expansions or essential safety and maintenance.

In addition, the Code introduces regulatory redundancy, investment uncertainty, and additional costs which the Code itself intends should be borne by the pipeline's customers. Whether or not the pipeline operator is willing or able to pass on such costs, the fact that these arise at all is unnecessary and inefficient. These issues are elaborated upon as follows.

(i) Benefits of competition already exist.

The preceding discussion and quotes referenced throughout this application clearly demonstrate that competition in the relevant markets already exists and that the application of the Code in respect to the GGP will make no positive contribution to increasing that situation.

The benefits arising from the competitively tendered development of the GGP were carefully evaluated by the State Government against a range of "State benefit criteria". The Energy Minister at the time stated (with emphasis added) in parliament that;

"The 'net value added' computer model utilised assessed the gross value added to the State under a variety of energy price scenarios. Costs of the major inputs such as construction materials, labour etc, are deducted to give net value added. This was found to be positive for the project contemplated. Nine selected consortia were interviewed and they provided written response to a large range of questions, structured to enable the project team to evaluate their bids against a range of State benefit criteria. These criteria included –

- Energy cost savings to WA
- accessibility - to suppliers and consumers
- Security - technical and financial
- Economic stimulus
- Social benefits

- Minimised requirements of Government.^{xcv}

This application has already referenced and discussed various statements and other evidence that indicates that these criteria have been satisfied to the full extent anticipated. The investment at the time was widely lauded within industry, public and government sectors.⁶¹

There may be a case to be made that in realising the anticipated benefits, the competition introduced by the GGP also had certain unforeseen consequences. Certainly questions were raised within the State Government once it was realised that the introduction of a cheaper alternative source of energy in the region would result in revenue reductions to the State owned electricity utility, Western Power. However, as the Energy Minister put it,

"That is what competition is about and members opposite should be focusing on the cost of power generation to mines and mineral processing operations in the goldfields, the north eastern goldfields and the Pilbara falling by 35 to 60 per cent because of that initiative."^{xcvi}

As has been shown, competition continues. The GGP competes with alternative fuel sources for generating electricity, as well as with reticulated electricity from the SWIS. Furthermore, as expectations of demand grow, proposals for effective and (socially and economically) efficient pipeline bypass arise. Coverage under the Code does nothing to enhance these conditions with respect to the GGP.

(ii) Increased regulatory costs and investment disincentives reduce asset life and the ability to compete or expand.

It needs to be considered that third party access was already available to the services provided by means of the GGP, before coverage under the Code occurred. Moreover, it was available on a commercial basis that factored in both a rate of return on the investment which was commercially acceptable within the relevant industry sector, as well as the cost of essential maintenance.

In contrast, access as provided by coverage under the Code has been demonstrated elsewhere to involve;

- increased regulatory expense,^{xcvii}

^{xcv} Mr C.J.Barnett, Hansard, 15 September 1993, page 3974, question no. 863.

^{xcvi} Mr C.J.Barnett, Hansard, 4 September 1996, page 5234, Question no. 457.

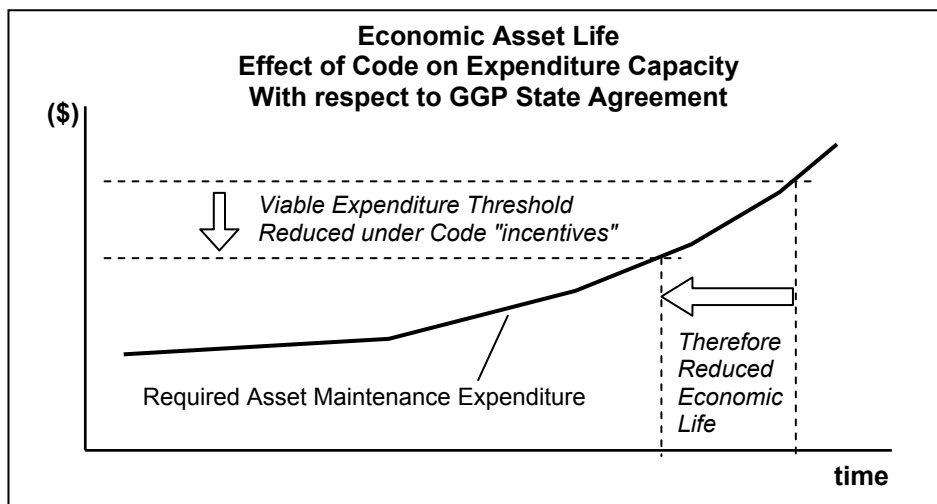
^{xcvii} Noting that under the funding arrangements implemented in Western Australia, Service Providers directly bear, in addition to their own costs of compliance, the full cost of the maintenance and activities of the Regulator and the Office of Gas Access regulation, as well as the consultants, fees and expenses incurred by them. In particular it should be noted that whereas existing pipeline users may be protected from having to bear the ultimate costs of regulation under their existing contracts, new third party access seekers (to which the Code is supposedly directed) would potentially be exposed to bearing the full cost of additional regulatory expense.

- notional capital write downs in value (effectively another form of regulatory expense),
- substandard rates of return within the relevant investment sector,^{xcviii}
- specific incentives to reduce expenditure.^{xcix}

The commercial reality of these mandatory impositions is a clear incentive on the covered Service Provider to reduce all expenditure wherever possible.⁶² This regulatory “incentive” to cut operational costs and withhold additional capital expenditure must eventually have a negative influence on the firm's capacity (despite its best and self-interested intentions) for expenditure on essential long term operational needs.

One significant impact arising from this reduced expenditure capacity, is that of ultimately reducing the economic life of the regulated asset. This is illustrated in the figure below.

Figure 6.



As the pipeline ages, the reasonable expectation is that expenditure on essential maintenance will tend to increase. At some future stage in the life of the pipeline (and assuming a state of equilibrium of throughput at some given level, and hence a constant revenue profile at that time), the useful life of the pipeline will be determined by the economics of maintaining it, all else remaining constant. Once the cost of maintenance exceeds the viable expenditure threshold, the asset will have reached the end of its economic life.

^{xcviii} The argument put forward by some regulators along the lines that regulated returns on equity for pipelines are (i) as high as indicated by theoretically deriving them from input values which have been “deemed” as appropriate by regulators in the first place, and (ii) that these theoretical returns are consistent with those derived from a portfolio of diversified asset holdings elsewhere in the economy, are entirely spurious and intentionally misleading. Nonetheless, the GGP State Agreement can be contrasted in that it very explicitly applies to the GGP on an asset-specific basis.

^{xcix} Some regulatory authorities have recently taken to describing the regulation under the Code as “incentive regulation”. What they mean by this, is that by capping the revenue that a regulated asset can earn and then progressively lowering the capped revenue in real (inflation adjusted) terms, the Service Provider is incentivised to reduce costs in order to stay in business.

If tariffs are set to recover only the theoretically established economically efficient (meaning minimum) short run equilibrium costs of providing the service, either the viable maintenance expenditure threshold will be reduced, or consumers will be exposed to unpredictable and possibly substantial price spikes. In either case, the social economic impacts are negative. Reduced expenditure levels will, as indicated in Figure 6, result in the abandonment threshold for the pipeline being reached at an earlier date than would otherwise be the case if normal commercial returns (relevant to the asset) were available to the service provider. The alternative - unpredictable price spikes - are clearly not in the best interests of consumers either.

The provisions of the State Agreement afford the GGT and its customers, protection against these effects (albeit that the specific interaction of the Code and the relevant clauses of the State Agreement have been and, under the Code process, seem likely to again be the subject of legal clarification). However, if the application of the Code were to result in arbitrary tariff reductions, as well as the preceding risks, this would be at the expense of new capital investment in infrastructure expansion. The impact of choking infrastructure expansion, which as has been demonstrated is vital to the promotion of the gas market and hence competition in energy and downstream resource development, would have an even more substantial and longer term negative social impact.

Mention has been made previously in this application, of another key difference between the Code and the obligations defined under the State Agreement access regime which preceded it and which continues to have force. This is the provision under the State Agreement which obliges the Service Provider to fund necessary expansions and extensions to the pipeline, compared to the provisions of the Code which both disincentivise further investment and relieve the Service Provider of the obligation to apply its own funds. Under the Code, if the Service Provider is to expand capacity, it will only do so to the extent that it can put in place take-or-pay contracts which transfer much of the risk back to the customer.⁶³

Thus, under the Code, while the right of access to developable capacity for third party users is maintained (although in no way enhanced), the distinction is that the Service Provider is only obliged to provide such access to the extent that the access seeker is prepared to directly and up front, fund any additional investment necessary. Under such conditions, there would have to be sufficient external benefit (from the perspective of the access seeker) to justify any investment in additional pipeline capacity, which implies some degree of cross-subsidisation. Furthermore, the prospective access seeker will only be prepared to expend funds to the extent that his own needs are met.

Such circumstances preclude any attempt to capture the economies of scale associated with taking a longer term view of capacity demand, which is so critical to realising efficiency in pipeline investment. This will result in growing economic barriers to entry for successive future gas access seekers, rather than the reverse condition, which is provided for under the State Agreement.

Compounding the redundancy of the dual access regime obligations to which the GGP is subject, the costs incurred under the Code are onerous. GGT estimates that it has incurred approximately A\$ 2.3 million (not including legal costs) in complying with the imposition of the Code to date. Nearly \$600,000 of this is accounted for by direct charges from the Regulator's office.

The expected future cost of Code coverage, assuming legal costs are not included, and only accounting for annual standing charges and periodical access arrangement reviews once every five years, are conservatively approaching A\$ 300,000 per year. On a perpetuity basis, this amounts to in the order of approximately A\$ 3.6 million dollars.

The existence of overlapping access regime obligations, inevitably throws up issues of differential interpretation and application – as evidenced by the recent dispute involving GGT and the Regulator in the Supreme Court. These have the resulted in huge costs to date and will continue to incur substantial costs into the future. This prospect is confirmed by the Regulator, who has adopted the view that the resolution of delays and disputes arising from differing interpretations of the Code by means of litigation, is both "necessary and helpful".⁶⁴

The cost incurred by GGT in complying with Code coverage of the GGP is substantial. In fact, under the funding arrangements enacted in Western Australia (and in contrast to the regulatory funding arrangements elsewhere in Australia), the full cost of maintaining the Regulator and the supporting Office of Gas Access Regulation and any consultant costs, fees and expenses incurred by them, is passed on to the market via Service Providers. In addition, the mounting cost associated with regulatory litigation as a result of the manner of implementation of the Code in Western Australia, needs to be considered. While it has not yet been legally determined as to the Regulator's ability or otherwise to also pass these legal costs on to Service Providers, the expense is both real and accumulating at an alarming rate.

If it is ultimately demonstrated that these legal costs are unable to be passed on to the market by the Regulator, then they will necessarily be borne by the State. This is obviously a cost to society, one that appears to be outside the direct control of the State itself,^c and an expense which consumes public funds which might have been better deployed for tangible social benefits.

These, along with the Service Provider's own cost of compliance, constitute the unavoidable price of "access (or increased access)" as afforded by application of the Code, even though open access was demonstrably already available to third parties wishing to transport gas on the pipeline. Furthermore, regardless of any lack of demonstrable benefit to users (or any

^c Under the Code, the activities of the Regulator are supposed to be independent of government direction. As a consequence, the State has no ability to either constrain the activities of the Regulator in incurring a mounting financial public liability, nor to cause the Regulator to be held accountable for this expenditure.

other party), the Code intends that these costs should ultimately be borne by the customers of the covered pipeline.

Finally, the hiatus which has existed since December 1999 as a result of the time taken to assess and debate/dispute the Access Arrangement proposed by GGT makes it impossible for both the pipeline owners and existing or prospective shippers to plan with any confidence. This represents an additional and substantial cost.

(iii) Coverage imperfectly substitutes and distorts already effective market forces.

The GGP has brought competition into the pre-existing energy markets which it services. However, its ability to compete is constrained (as it is with all pipelines) in so far as its economies of scale permit. The capacity commitments made by the original owners and Third Parties which underscored the construction of the GGP, along with the capacity expansion requirements agreed by GGT with the State Government, defined the size and hence construction cost of the pipeline. These parameters dictate a certain economy of scale, which in turn governs the viable range within which transportation services must be priced.

Market growth that gives rise to increased capacity demand, as well as price signals defined by the existing economy of scale, will result in new investment in additional alternative capacity having greater economies of scale (as per the GEMM pipeline proposal).

What this represents is the development of an integrated energy market, facilitated by normal competitive market forces at work. That this should occur by virtue of appropriate price signals, responsive to the needs of the market and not by central planning, has been extolled by the ACCC as an essential outcome of regulatory reform.⁶⁵

The Tribunal has observed a number of times that regulatory controls designed to mimic the operation of a free marketplace are second best to the outcomes produced by actual competition. In the EGP Decision, the Tribunal concluded that;

"coverage would substitute regulation for the market, when the market has been shown to be exercising effective discipline over market power".^{ci}

The distortional effect on private investment decision analysis was elaborated upon in a recent presentation by the Chairman of the Productivity Commission, which concluded that;

"By 'truncating' the potential returns from risky investments, an apparently benign regulatory policy can actually kill the incentive to invest in the first place.

^{ci} Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2, Australian Competition Tribunal, 4 May 2001, , page 11.

In the case of access regulation, there may also be perverse incentives for investors to build smaller facilities than would be socially desirable, so as to ensure that there is little spare capacity beyond their immediate requirements, thereby removing any threat that they would be required to grant access at prices they considered too low^{cii}.

To quote one ACCC commissioner who was discussing the merits afforded by Australia's national access regime, of which the Code forms a part,

“Regulation can open up an “essential facility” to third party access to promote competition in the contestable upstream and downstream markets. It can ensure the terms of access are reasonable and prices are efficient. Efficient prices allow for necessary new investment to be undertaken and for firms to obtain appropriate returns commensurate with the risks involved.”^{ciii}

Under the State Agreement access regime, the GGP has already achieved these objectives. GGT contends that in respect to the GGP, the Code contributes no enhancements in fulfilling the objectives of the national access regime, over the terms of access and market conditions which already exist, and continues to exist, under the State Agreement access regime.

Conclusion for Criterion (d)

GGT contends that for the following reasons, coverage under the Code is contrary to the public interest.

- (i) Benefits of competition already exist,
 - (ii) Redundant regulatory costs and “incentives” under the Code reduce asset life and the ability of the GGP to compete or expand,
 - (iii) Coverage imperfectly substitutes and distorts already effective market forces.
-

^{cii} Presentation: The ‘baby and the bath water’: avoiding efficiency mishaps in regulating monopoly infrastructure, Gary Banks, Chairman, Productivity Commission, 5 July 2002, page 8.

^{ciii} Presentation: “How is The Current Regulatory Regime Contributing To Further Reform And Competition In Australia?”, David Cousins, Commissioner, ACCC, 24 July 2001, page 2.

ATTACHMENTS /

- ATTACHMENT 1 : RELEVANT CHRONOLOGY**
- ATTACHMENT 2 : COMPARISON OF THIRD PARTY ACCESS – CURRENT AND PROPOSED**
- ATTACHMENT 3 : GAS RESERVES IN WESTERN AUSTRALIA**
- ATTACHMENT 4 : DETAILED SUMMARY OF DOWNSTREAM MARKET ANALYSIS**
- ATTACHMENT 5 : GAS QUALITY SPECIFICATION**
- ATTACHMENT 6 : OVERVIEW OF ECONOMIC DEVELOPMENT TARIFF (EDT)**

APPENDICES :

- APPENDIX 1 : LOCATION MAPS**
- APPENDIX 2 : GOLDFIELDS GAS PIPELINE: RELEVANT DOWNSTREAM MARKETS, VENTNOR CONSULTING GROUP, MARCH 2003.**
- APPENDIX 3 : COMPARISON OF STATE AGREEMENT AND CODE AGAINST THE CRITERIA OF THE COMPETITION PRINCIPLES AGREEMENT.**
- APPENDIX 4 : GGT SUBMISSION TO THE PRODUCTIVITY COMMISSION REVIEW OF THE NATIONAL ACCESS REGIME, 2001.**
- APPENDIX 5 : ARTICLE: SEARCH FOR NEW CUSTOMERS, PROSPECT, DRD, DEC'95/FEB'96**
- APPENDIX 6 : THE DEVELOPMENT OF GORGON AREA GAS.**
- APPENDIX 7 : GOVERNMENT MEDIA STATEMENTS.**

GLOSSARY

ABARE	Australian Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
Act	Gas Pipelines Access (Western Australia) Act, 1998 (or "GPAA")
AGA	Australian Gas Association
APPEA	Australian Petroleum Production and Exploration Association
CoAG	Council of Australian Governments
Code	Third Party Access Code for Natural Gas Pipeline Systems
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DBNGP Draft Decision	"Draft Decision: Proposed Access Arrangement: Dampier to Bunbury Natural Gas Pipeline", Independent Gas Pipelines Access Regulator, Western Australia, 21 June 2001
DMPR	W.A. Department of Mineral and Petroleum Resources
DoIR	W.A. Department of Industry and Resources
DRD	W.A. Department of Resource Development
EDT	Economic Development Tariff
EGP	Eastern Gas Pipeline
EGP Decision	"Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT2", Australian Competition Tribunal, 4 May 2001
GEMM	Geraldton to Mount Margaret Pipeline
GGP	Goldfields Gas Pipeline
GGP Draft Decision	"Draft Decision: Access Arrangement: Goldfields Gas Pipeline", Independent Gas Pipelines Access Regulator, Western Australia, 10 April 2001
GGT	Goldfields Gas Transmission Pty Ltd
GGTJV	Goldfields Gas Transmission Joint Venture (original owners)
GJ	GigaJoule (ie. 10^9 Joules)
GWh	Gigawatt hour
km	Kilometre
kVa	kiloVolt ampere
LNG	Liquified Natural Gas
LPG	Liquid Petroleum Gas
MW	MegaWatt
NCC	National Competition Council
OffGAR	Western Australian Office of Gas Access Regulation
Owners	The current GGT Joint Venture owners
PJ	PetaJoule (ie. 10^{15} Joules)
Regulator	Western Australian Independent Gas Pipeline Access Regulator
SECWA	State Energy Commission of Western Australia
State Agreement	Goldfields Gas Pipeline Agreement Act, 1994
SWIS	South West Interconnected System (for electricity transmission)
Tcf	10^{12} cubic feet
TJ/d	TerraJoule (ie. 10^{12} Joules) of gas per day
TPA	Trade Practices Act 1974
Tribunal	Australian Competition Tribunal
WMC	WMC Resource Pty Ltd

END NOTES

-
- ¹ "The [GGP] project is seen to offer major benefits to the State. Some of these benefits are:
- The better positioning of our mining and mineral processing industry among the world competitive producers through lower energy costs and more reliable supply.
 - The stimulation of increased mineral processing and new mineral processing activity by secure lower priced electricity supply and the availability of natural gas as a process fuel.
 - The increase in royalties to the State flowing from expanded mining activity.
 - The generation of jobs from the construction and operation of the pipeline, and from the associated developments consequent upon the availability of natural gas.
 - The generation of electricity from natural gas in Kalgoorlie will reduce the load on the Muja to Kalgoorlie transmission line to more reasonable levels, saving the presently high line losses and allowing more reflective competition in energy prices in Kalgoorlie.
 - Development by the private sector of a natural gas pipeline from the north west to the goldfields will open up significant new markets for gas producers and stimulate further investment by producers in proving up natural gas reserves and in production facilities.
 - By substitution of imported fuel oil with Australian natural gas and by increased mineral and processed mineral exports from a more competitive industry, our national balance of payments will be improved."

Mr. C.J.Barnett, Hansard, 29 March 1994, page 10791, Second reading.

- ² "Downstream processing and value adding is the way we must go. If we do not, ultimately the unrefined and raw products produced by this State will be worth little on the world market. Those products will not be refined unless this State can deliver energy to the source of the mining of those minerals." Mr. J.Grill (Eyre), Hansard, 6 April 1994, page 11523, Second reading.

- ³ "SECWA had looked at a proposal for a pipeline and in its view it was not viable. It examined the proposal from time to time over the years." Mr. C.J.Barnett, Hansard, 6 April 1994, page 11524, Second reading.

- ⁴ "Hon Mark Nevill and I went to Canberra and sought advice from the Australian Bureau of Agricultural and Resource Economics as to whether such a pipeline would be feasible and viable. Its advice was also in the negative because of lack of demand, which was very disappointing." Mr. GRILL, Hansard, 6 April 1994, page 11524, Second reading.

- ⁵ "On 17 April [1993] the Government sought expressions of interest in the project to bring gas to the goldfields. Some 60 inquiries were received and

from them 16 formal submissions have been made. Those submissions, which are of a very high standard, involve national, international and local companies." Mr C.J.Barnett, Hansard, 30 June 1993, page 859, question no. 45.

6 "The goldfields gas transmission joint venture was assessed by the team to be a highly competent group with a particularly well thought out proposal, integrating the proposed goldfields gas pipeline as a transmission system with the demand of the market." Mr. C.J.Barnett, Hansard, 22 September 1993, page 4501, question no. 1001.

7 "This agreement is pioneering in that it provides for private sector development of major infrastructure under commercial terms with light handed regulation. I believe the terms of this agreement are consistent with decisions made at the Council of Australian Governments' meeting in Hobart in February 1994 with respect to the free and fair trade in natural gas. The agreement ensures non-discriminatory access and tariffs for all future use of the pipeline and obligates the joint venturers to pursue market growth and to provide for further development of the pipeline capacity to serve that growth." Mr. C.J.Barnett, Hansard, 29 March 1994, page 10793, Second reading.

8 "Goldfields Gas Pipeline

During the year, the Government negotiated with various private sector parties to build, own and operate a natural gas pipeline. It will extend from the north-west of the State to the Goldfields Region and will be capable of transporting natural gas to Mt Newman, Mt Keith, Leinster and Kalgoorlie (see map). The Bureau participated in these negotiations and provided advice, particularly in relation to issues concerning third-party access to the pipeline and the pricing principles.

In September 1993, the Government invited a group of Joint Venturers – including Western Mining Corporation, Normandy Poseidon Ltd and BHP Minerals Pty Ltd – to undertake additional studies to progress this project. In May 1994 the State entered into an agreement with the Joint Venturers, embodied in the Goldfields Gas Pipeline Agreement Act. The State Agreement was accompanied by a side letter detailing, amongst other things, guidelines for pricing principles to be proposed by the Joint Venturers, subject to approval by the Minister." Energy Policy and Planning Bureau (Government of Western Australia), Annual Report 1993-94, page 16.

9 Conveyed verbally and indicated (for example) in:

"Mr Kolf said that differing interpretations of the gas access code were a source of delays and disputes, and that parties most affected by an access decision would be the ones to test a new code in detail. Litigation could be necessary and helpful, Mr Kolf said, whenever the interpretation of phrases containing the word 'normally' came into dispute and required specific

determination." Regulator talks on gas access, Peter Kolf (Executive Director, OffGAR), WA Business News, 8 August 2002, page 14.

10 'The uniform laws and subsidiary legislation referred to in sub-clause (2) shall not have effect to the extent that the joint venturers can demonstrate that the uniform laws or subsidiary legislation there referred to have or are likely to have a material adverse effect on the legitimate business interests of the joint venturers but in any event, insofar as any such uniform laws or subsidiary legislation may purport to apply to the Initial Committed Capacity, such of those uniform laws or that subsidiary legislation shall only so apply to the extent that the Initial Committed Capacity is, from time to time, unutilised.' Goldfields Gas Pipeline Agreement Act 1994, clause 21(3).

11 "Similarities between regimes

While the code may appear more prescriptive than Part IIIA, both are essentially based on the same principles.

Part IIIA was the basis upon which the code was developed and the intention was that an 'access arrangement would be similar in many respects to an undertaking under Part IIIA'. Further, the code was specifically designed to address access to natural gas pipelines and is a major component of access regimes that have been certified as effective in a number of jurisdictions." Draft greenfields guideline for natural gas transmission pipelines, ACCC, June 2002, page 9.

12 For instance: "As such, the CAPM methodology does not make allowance for adjustments to the cost of capital to account for risk that is specific to the Goldfields Gas Pipeline. As discussed above, firm-specific risk is not relevant as these risks can be eliminated by investors holding a well diversified portfolio of assets", Draft Decision: Access Arrangement: Goldfields Gas Pipeline, Independent Gas Pipelines Access Regulator, Western Australia, 10 April 2001, section 5.7.8, page B-141.

13 The Gas Pipelines Access (Western Australia) Act 1998 states;

97. Temporary continuation of access arrangements for the Goldfields Gas Pipeline, and continuation of certain rights

(1) *The existing access arrangements for the gas transmission pipeline that is the subject of the ratified Agreement are taken to be an approved Access Arrangement under the Code until 1 January 2000.*

(2) *In subsection (1) —
"existing access arrangements" means the provisions of clause 20 of the ratified Agreement.*

[...]

(6) *In this section —*

“ratified Agreement” means the Agreement within the meaning in section 3 of the Goldfields Gas Pipeline Agreement Act 1994.

And the Goldfields Gas Pipeline Agreement Act 1994, referenced in (6) above, states;

3. Interpretation

(1) *In this Act, unless the contrary intention appears —*

“the Agreement” means the Goldfields Gas Pipeline Agreement, a copy of which is set out in Schedule 1, and includes that Agreement as varied from time to time in accordance with its provisions.”

14 “Section 1.9(a) of the code requires the NCC (and decision-maker) to be satisfied that competition would be promoted in a dependent market by regulation under the code. This is to be compared with the likely state of competition without regulation under the code (EGP decision). If the pipeline is regulated by an undertaking, it is unlikely that regulation under the code would promote competition, so criterion (a) will not be met.

This interpretation of section 1.9(a) of the code is further supported by a recent decision of the designated Minister to accept the recommendation of the NCC and not declare the rail network services provided by Freight Australia which were the subject of an application for declaration. The basis for this decision was that declaration would not have promoted competition given that access was already provided under the Victorian access regime. Accordingly s. 44H(4)(a) of the TPA was not met. Section 1.9(a) of the code is essentially the same as s. 44H(4)(a).” Draft greenfields guideline for natural gas transmission pipelines, ACCC, June 2002, page 10.

15 “However they (DRD) did say that in the early stages of the pipeline the operation might well be marginal, depending on a number of factors. One of the most important will be the cost of constructing the pipeline.” Mr. J.Grill, Hansard, 6 April 1994, page 11565, Second reading.

16 “Initial Pipeline size

(5) Unless otherwise agreed by the Minister, the initial development of the Pipeline shall be such that its size is the greater of —

(a) a diameter of 400 mm from the commencement of the Pipeline through to Newman thence of 350 mm through to Kalgoorlie; and

-
- (b) such diameter or diameters as are required so that the initial operating capacity of the Pipeline is sufficient to provide for all Initial Committed Capacity,

and such that —

- (c) the Pipeline shall be suitable for operation at a pressure of not less than 10,200 kPa; and
- (d) the capacity of the Pipeline shall be able to be expanded, by using additional compression, by a minimum of 50% of the Initial Committed Capacity." Goldfields Gas Pipeline Agreement Act 1994, Clause 9(5).

17 "All of this provides important context for the recent concerns expressed by transmission pipeline owners about the impact of access regulation in the gas industry. Some of the views expressed have confused the distinction between, on the one hand, the issue of whether pipelines are likely to satisfy the criteria for coverage under the Code with, on the other hand, the issue of how pipelines should be regulated under the Code if they are covered. Let me be as clear as possible on this important distinction. Pipelines that do not have relevant, enduring and substantial market power should not be covered by the Code. I believe that the Council and the Tribunal have already demonstrated that the Code should not and will not be applied where it is not needed. However, pipelines that do satisfy the criteria for coverage should be regulated to ensure that the substantial market power that they possess is addressed in the interests of competition in the gas market and consumers." "The Report Card on Electricity and Gas Reform: A presentation by Ed Willett Executive Director, National Competition Council, to the Inaugural Australian Energy Users Conference 2001", 19 November 2001, page 24.

18 For example: "Our industry looks to be in good shape. Governments are recognising the economic and environmental benefits of the gas that we transport, policy is said to be in train to encourage gas use and producers, with new sources of gas supply, are locked in battle to contest supply to new and expanded markets. And yet, at our International Convention only 15 days ago:

- I, as President, emphasised the failure of government to engage in a serious attempt to address our concerns regarding repressive economic regulation;
- our pipeline owner members declared that they would not invest further in Australia unless, and until, problems with the economic regulatory framework are addressed; and
- many of our supplier members expressed grave concern about the prospects for new development and for continuity of business activity in their pipeline business divisions." "Major Planned Pipeline Extensions", Presentation by Mike Lauer to the 2001 AGA Convention, 16 November 2001, "Introduction".

Access to Pipeline and Pipeline expansion

20. (1) The Joint Venturers shall provide (and are authorized by the State to provide) in accordance with this Clause non-discriminatory Third Party access to such capacity, including Developable Capacity, of the Pipeline as may from time to time not be contracted or utilised (including so much of the Initial Committed Capacity as is, from time to time, unutilised).
- (2)...
- (4) The Joint Venturers shall use all reasonable endeavours to develop the capacity of the Pipeline (including the installation of additional compressor stations and looping of the Pipeline) as may be necessary from time to time to accommodate the requirements of Third Parties wishing to transmit gas through the Pipeline. The obligations of the Joint Venturers under this subclause shall be subject to it being technically feasible and economically feasible to so develop the capacity of the Pipeline and shall not be taken to impose on the Joint Venturers any requirement to construct lateral pipelines.
- (5) If the Minister considers that the Joint Venturers have not met the reasonable needs of a Third Party by developing the capacity of the Pipeline pursuant to this Clause, the Minister may direct the Joint Venturers to submit, within 3 months of that direction or within one month after all necessary EP Act approvals have been obtained, whichever is the later, proposals for expansion of the capacity of the Pipeline.
- (6) The Joint Venturers shall comply with any direction pursuant to subclause (5) and the provisions of subclauses (1), (2) (3) and (4) of Clause 10 shall mutatis mutandis apply to the proposals. The Joint Venturers shall implement the decision of the Minister or any award on arbitration as the case may be in accordance with the terms thereof PROVIDED HOWEVER that the Joint Venturers shall not be required to implement such proposals where it is not technically feasible or economically feasible for them to do so, having regard to the legitimate business interests of the Joint Venturers.
- (7) The Joint Venturers shall, at the cost of the relevant Third Party, undertake the connection to the Pipeline of a lateral pipeline for any Third Party reasonably requiring such connection, subject to —

-
- (a) the operational and technical requirements necessary for the safe and reliable operation of the Pipeline and any other pipelines to which the Pipeline is or is committed to be connected or which are or are committed to be connected to the Pipeline;
 - (b) the Third Party access and tariff provisions relating to the Pipeline pursuant to this Agreement;
 - (c) the applicable billing and metering arrangements;
 - (d) compliance with the gas quality specifications then applicable to the Pipeline; and
 - (e) where reasonably required, the provision of security for the payment of transmission charges by the relevant Third Party.

For the purpose of this subclause, "connection" means the physical connection of the Third Party's pipeline to the Pipeline and the installation of valves, metering equipment, control systems and other appurtenances necessary as a consequence of the connection.

- (8) Should a Third Party wishing to obtain access to the Pipeline advise the Minister that he has not been able, for a period of at least 2 months, to reach agreement with the Joint Venturers upon such access or on terms and conditions to be applicable thereto and provide to the Minister such details of the matter in question as the Minister may request, the Minister may require that the Joint Venturers forthwith provide the Minister with details of the matter as are available to them. This subclause does not apply in relation to the determination of the Initial Committed Capacity under Clause 8.
- (9) Consequent upon an advice pursuant to subclause (8) the Minister may, unless the Joint Venturers enter into arrangements with the person concerned to the reasonable satisfaction of the Minister for resolution of the matter, determine reasonable terms and conditions, consistent with the tariff setting principles then applicable under Clause 22 upon which transmission services shall be provided to the person concerned (which may include a direction to expand the capacity of the Pipeline), but in making any such determination, the Minister shall have due regard for —

-
- (a) the terms of this Agreement;
 - (b) the legitimate business interests of the Joint Venturers;
 - (c) the interests of all Third Parties holding contracts for transmission services in the Pipeline;
 - (d) the interests of others in whose favour a determination has been made under this subclause; and
 - (e) the operational and technical requirements necessary for the safe and reliable operation of the Pipeline.
- (10) The Joint Venturers shall comply with any reasonable direction by the Minister under subclause (9) PROVIDED THAT they shall not be required to expand the capacity of the Pipeline unless it is technically feasible and economically feasible (having regard for the matters referred to in paragraph (b) of subclause (9)) to do so. If the Joint Venturers form the opinion that the direction of the Minister is unreasonable or that it is not technically feasible or economically feasible to expand the capacity of the Pipeline, they may refer the matter to arbitration pursuant to Clause 37.
- (11)

Goldfields Gas Pipeline Agreement Act 1994, Clause 20.

20

Gas transmission market growth

19. During the currency of this Agreement the Joint Venturers shall actively promote, and cause any operator of the Pipeline to actively promote, use of the Pipeline by Third Parties and shall pursue growth in the market for gas transmission through the Pipeline. The Joint Venturers shall confer with the Minister upon request of the Minister from time to time in respect to their endeavours pursuant to this Clause.” Goldfields Gas Pipeline Agreement Act 1994, Clause 19.

21

"The development of Gorgon can deliver additional gas to Western Australia's existing gas distribution system and encourage the extension of the pipeline network. A second major gas supplier in the North West will have the dual impact of greatly expanding the market and increasing gas competition, thereby encouraging investment in Australian-based developments. This new supply of competitive gas will create opportunities for clean energy infrastructure and for new and existing industries wherever gas is delivered within the State.

Gorgon will be an "enabler" for a range of industries relying on the availability of abundant supplies of gas on world competitive terms. The benefits will flow to traditional industries such as minerals processing, the new gas-based sunrise industries and to a wide range of smaller players attracted by opportunities flowing from the expanding industrial base." I.J.Grose, The Development of Gorgon Area Gas, 23 April 2002, page 2. (See Appendix 6 to this application).

- 22 "WA gas utility AlintaGas Limited has announced a Memorandum of Understanding with Alcoa World Alumina Australia to jointly develop co-generation power plants at Alcoa's alumina refineries in WA.

If approved, the plants will be developed on a staged basis to match growth in the electricity requirements for the South West Interconnected System, with the first plant operational in late 2004.

Alcoa operates three WA refineries, Wagerup, Pinjarra and Kwinana and the partnership plans a rollout of 120-150MW cogen units on a modular basis, potentially up to ten depending on electricity sales. Alcoa currently operates a 254MW gas fired generator for its own power needs.

Under the AlintaGas proposal Alcoa will use all of the steam output from the co-generation plants in its alumina refineries and Alinta will sell the electricity into the retail electricity market." Media announcement: AlintaGas enters electricity market, AlintaGas, 4 July 2002.

- 23 "Most power generators within the study area are fuelled by diesel. Those generators located in towns attract the diesel fuel excise. In remote locations, diesel can be the only viable fuel source and the excise penalises the residents and businesses in these towns. There is an immediate requirement to ensure the equitable application, or preferably, exemption from the diesel fuel excise as it currently applies to domestic power generation, to ensure continued regional development. ..." Southern Cross - Esperance Regional Minerals Study, August 2000, Department of Resources Development, (Connell Wagner), Key Findings: Executive Summary, page (ii).

- 24 "4.2.3 Submissions from Interested Parties

...
Inlet Point

- North West Shelf Gas

We would request that the Regulator ensure that provision is made in the Access Arrangement for an alternative Inlet Point(s) from a possible future connection to the GGP from the Dampier to Bunbury Natural Gas Pipeline. Such a new inlet point would allow physical access to the GGP (and therefore Eastern Pilbara and Goldfields customers) by the four other gas producers in the north west (including the North West Shelf Joint Venture as well

as backhaul from producers further south). Equitable access to the GGP and these customers by all gas producers is required to allow circumstances in which true competition between gas producers might occur.” Draft Decision: Access Arrangement: Goldfields Gas Pipeline, OffGAR, 10 April 2001, section 4.2.3, page B-30.

25 “The North West Shelf Gas submission highlights the possibility of an alternative Inlet point to the GGT from the DBNGP. Anaconda would welcome such a connection, as it would enable all gas suppliers to provide gas to Users, opening the GGT to full competition between gas producers. It is positive that the Regulator has recognised the need for the Access Arrangement to incorporate the possibility of an alternative Inlet Point.” Submission On Access Arrangement Draft Decision, Prepared By Anaconda Nickel Limited, July 2001, S. Lill & A. Baron, Page 7.

26 “Amendment 2

The proposed Access Arrangement should be amended to make provision for the Reference Service to be capable of accommodating alternative and multiple Inlet Points in a single Service Agreement in the event that additional Inlet Points are established on the pipeline.” Draft Decision: Access Arrangement: Goldfields Gas Pipeline, OffGAR, 10 April 2001, page B-31.

27 “Access to SEC Dampier to Bunbury gas transmission pipeline

17. (1) For the purposes of this Agreement, the State shall ensure that the State Energy Commission, where it is technically feasible and economically feasible so to do and subject to compliance by the relevant Third Party with the gas quality specifications then current for the Dampier to Bunbury pipeline, grants access to any Third Party wishing to transmit gas to the Pipeline [i.e. the GGP] through the Dampier to Bunbury pipeline at fair and reasonable terms and conditions based on principles (including, but not limited to, those relating to expansion of capacity) that are generally consistent, where relevant, with the principles of access and transmission and the tariff setting principles then applying to the Pipeline.

(2) Should any Third Party transmitting or wishing to transmit gas through the Dampier to Bunbury Gas pipeline to the Pipeline advise the Minister that he has not been able, for a period of at least 2 months, to reach agreement with the State Energy Commission upon such access or on terms and conditions to be applicable thereto and provide to the Minister such details of the matters in question as are available to that Third Party and as the Minister may request, the Minister may require that the State Energy Commission provide the Minister with details of the matter forthwith.

-
- (3) Consequent upon an advice pursuant to subclause (2) the Minister shall, unless the State Energy Commission enters into arrangements with the Third Party concerned satisfactory to the Minister and to the Third Party for resolution of the matter, make a determination as to reasonable terms and conditions and tariffs which he reasonably considers are appropriate in the circumstances for use of the relevant section of the Dampier to Bunbury pipeline by the Third Party. Unless the Minister is advised, within one month of his determination, that the State Energy Commission and the Third Party have resolved the matters between them or that those matters have been referred to arbitration for resolution, the Minister, on the expiration of that period, shall cause the Energy Minister to direct the State Energy Commission to apply the determination of the Minister.
- (4) Any direction by the Energy Minister shall have due regard to operational or technical requirements necessary for safe and reliable operation of the Dampier to Bunbury pipeline and the provisions of this Agreement.”

Goldfields Gas Pipeline Agreement Act 1994, Clause 17.

28 “The question of whether a Delivery Point is provided is not a matter for the approval of the Access Arrangement. This is a question of whether there is a Shipper who might want capacity at that point and then whether for Epic Energy it is commercially viable to do so.” Epic Energy Submission 9, in Draft Decision: Proposed Access Arrangement: Dampier to Bunbury Natural Gas Pipeline, OffGAR, 21 June 2001, section 7.3, page B-317.

29 “The preliminary work and current work shows that the savings to energy consumers from the gas to the goldfields pipeline project will vary from around 15 per cent in Kalgoorlie to about 30 per cent at Mt Keith and perhaps up to 50 per cent in the eastern Pilbara.” Mr C.J.Barnett, Hansard, 22 November 1994, page 7419, Question no. 617.

30 “Members opposite have got it all wrong. The whole point about the pipeline is to develop industry and to introduce competition in order to reduce prices. I would be the most foolish Minister in the world if I told them they could not reduce prices. Why do members opposite think we are deregulating the energy industry and introducing competition?” Mr. C.J.Barnett, Hansard, 29 November 1994, page 8000, Question no. 641.

31 Nevill: “What is the basis for the claim by the Minister for Resources Development Legislative Council that energy costs will be reduced by 30% at the end of the goldfields gas transmission pipeline?”
Moore: “I thank the member for some notice of the question. The answer is: the comparison of the estimated cost of delivered distillate against delivered gas.” Nevill/Moore, Council, 24 October 1996, p7172.

32 “5.1.3 Summary

Many Australian regulators acknowledge that ODV has significant merit but point out that it is prone to some subjectivity and circularity.

The use of ODV for the Western Australian network businesses has resulted in significant economic write-down of asset values particularly where gas has provided competition for transmission lines. This has occurred on the Kalgoorlie 220kV transmission line and the Karratha to Port Hedland 220kV transmission line. The rural distribution lines are also subject to economic write-down in value due to the high cost of the rural network.” Triennial Review of pricing for access to Western Power’s electricity transmission and distribution networks, Public Discussion Paper, Western Power Corporation and the Office of Energy for the Electricity Access Steering Committee. May 2000. Page 37.

33 “Further, Anaconda has studied non metal projects which are extremely sensitive to gas prices, such as the Mt Weld Phosphate Project where gas prices are approximately 20% of the overall cost. The Mt Weld Phosphate Project requires an ammonia plant where 95% of the operating costs are gas*. We have then considered increasing the ammonia plant capacity to allow production of ammonium nitrate, sodium cyanide and urea, all of which show positive returns – subject to gas price.” Anaconda Response to GGT submission on OffGAR Draft Decision, 12 July 2001, Response point 3, page 3.

**[Note: clearly the second part of this statement is somewhat misleading, in that the ammonia plant referred to, being a requisite part of the Mt Weld Phosphate Project, would be already included in the previously stated estimate of the overall cost impact of delivered gas].*

34 “CORPORATEFILE.COM.AU
WMC Limited recently reported a 48 per cent fall in equity profit after tax to \$401.7 million for the year to December 31, 2001 from \$764.9 million in the previous corresponding period (pcp). What explains the variance from last year's profit?

CEO HUGH MORGAN

By far the largest factor explaining the variance from last year's profit was the dramatic fall in commodity prices. Nickel prices fell by 31 per cent, copper by 13 per cent and there was a further fall of 4 per cent from already low prices for fertilizers.” Open Briefing: CEO Mr H.Morgan on Profit & Outlook, WMC LIMITED, 14 March 2002.

35 “NICKEL

Nickel prices were significantly higher during the quarter, with the average LME nickel price gaining 23 per cent to US\$2.81 a pound. The range was

US\$2.61 a pound in mid-January to US\$3.11 a pound in mid-March, the highest since June 2001. Pricing support came from speculative and technical buying, low inventories, export curtailment by Norilsk Nickel and the release of better than expected economic data in the USA. LME stocks fell by 1,866 tonnes to 17,100 tonnes. Supply side conditions are supportive for continuing firm prices.

GOLD

The gold price traded between US\$276 an ounce and US\$308 an ounce [i.e. approx. 10% swing] before finishing the period at US\$303 an ounce. The gold price reached a 2 year high during the quarter due to several significant factors: a possible end to the recent US\$ strength, the devaluation of the Argentine currency and increasing tensions in Central Asia and the Middle East." First Quarter Activities Report, WMC LIMITED, 15 April 2002.

36 "WMC DELIVERED IN TOUGH MARKET CONDITIONS

In tough business conditions, WMC continued to deliver relatively good results. Our businesses had strong cash flows, even through one of the worst periods of the commodity cycle.

The second half of 2001 was particularly difficult with copper prices falling to 14-year lows in October. Nickel and aluminium prices fell 20 per cent and 13 per cent respectively. This is in stark contrast to buoyant conditions in the previous year. However, looking at the beginning of 2002 there are some encouraging signs of metal price recoveries." Chairman's Address to Shareholders, 8 June 2002.

37 WMC posted an after tax profit of \$401.7 million and declared a total dividend of 29 cents a share. We generated nearly \$943 million in cash flow from operations. We reduced debt by \$778 million and our gearing fell from 37.8 per cent to 30.3 per cent. Other financial achievements included delivering a cash flow-to-debt-ratio of 45 per cent and reducing capital expenditure by 4 per cent to \$456.9 million." ibid.

38 "CEO HUGH MORGAN

The nickel business is already efficient and low cost and given reasonable prices, it will also be a strong cash producer. Prices across our businesses have improved this year and our currency hedging position gets better from the beginning of 2002.

CORPORATEFILE.COM.AU

WMC has little remaining commodity price hedging but retains some US\$/A\$ currency hedging. Currency and commodity price hedging losses in 2001 were \$282.1 million before tax. What hedging contracts were closed out in 2001 and what hedging remains?

CEO HUGH MORGAN

The hedging position in 2001 was substantially greater than what remains in the hedge book. Our main hedging is currency and as at 31 December the mark to market of the currency hedgebook was about \$850 million. That will get closed out progressively over the next six to seven years.

If prices remain at similar levels, the hedging loss in future years will be about \$150 million dollars per annum lower than the hedging losses we recorded in 2001. Company Announcement, Open Briefing: CEO Mr H.Morgan on Profit & Outlook, WMC Ltd, 14 March 2002

39 “The estimates of own price elasticity of demand for natural gas show that demand in the residential, commercial and industrial markets is relatively price inelastic, in both the short run and the long run. In other words, a one percent fall (rise) in the price of natural gas will result in an increase (decrease) in the quantity demanded of less than one percent.

Of the three market segments, demand for gas is most price responsive in the residential market, with a one percent fall (rise) in the price of gas resulting in an estimated increase (reduction) in the quantity of gas demanded of 0.78 percent.

The estimates of cross price elasticities of energy demand also show that the residential market is characterised by a relatively high responsiveness of gas demand to changes in electricity prices. If electricity prices fall, residential customers are quite willing and able to substitute out of gas. In contrast, they are less willing or able to reduce their consumption of electricity if gas prices fall (estimated elasticity of 0.15). This result reflects the relatively limited substitution possibilities - that is, there are some applications for which electricity will continue to be used even if gas prices fall.” Price Elasticities of Australian Energy Demand, AGA Research Paper no.3, The Australian Gas Association & ABARE, September 1999, Summary, page 7.

40 “For the own price elasticities, an interesting result is that electricity demand is found to be less responsive to price changes than is gas demand. ... The most reasonable explanation for this is that there are some applications, such as lighting, for which there are no alternatives to electricity, while for gas there are alternatives in virtually every application.” *ibid*, page 25.

41 “The estimates from this study are not strictly comparable with those from previous studies, as this study is the first to apply the same analytical method to all sectors over the period 1973-74 to 1993-94. However, it is interesting to note that the estimates are broadly in line with several previous estimates which indicate that energy demand in general and gas demand in particular is relatively unresponsive to price changes.” *ibid*, Section 5: Concluding Comments, page 27.

42 “Even where monopoly power is exercised, it may not have significant negative impacts on efficiency. In particular, to the extent that monopolists

can structure their price menus efficiently, so that prices are high for the inelastic segment of demand and low for the elastic segment, there may be little distortion in supply or consumption patterns.

For example, in the case of airports, there are numerous examples of airport price structures designed to promote or retain marginal users, including direct incentives designed to encourage additional flights and new entrant airlines.” Presentation: The ‘baby and the bath water’: avoiding efficiency mishaps in regulating monopoly infrastructure, Gary Banks, Chairman, Productivity Commission, 5 July 2002, page 5.

43 “The relatively inelastic demand for the industrial market could be hiding significant variations in particular industries. For example, in manufacturing, the estimated [own] price elasticity of gas demand is quite high (-1.06), while in the mining sector it is close to zero.” Price Elasticities of Australian Energy Demand, AGA Research Paper no.3, The Australian Gas Association & ABARE, September 1999, Section 4: Main Results, page 22.

44 For instance (emphasis added); "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." Draft Decision: Access Arrangement: Tubridgi Pipeline System, OffGAR, 7 August 2000, page B-81.

Also, in responding to a question on this very statement at a public forum (convened as part of the regulatory process under the Code), the Regulator's representative responded (with emphasis added); "In looking at a balance of interests, obviously it's in the interests of the Service Provider to have as high a value of the initial capital base as can be achieved. Obviously then that is reflected in their depreciation allowances and their return on capital.

In considering the interests of users though, I guess the criterion that has been adopted, certainly in Western Australia but also in the Eastern States, is that by and large the advent of regulation should not result in an increase in tariffs to the users of the pipeline service. I suppose it's a reasonable expectation of users that with the advent of regulation, tariffs would be less than or equal to what they are at present, so that is where in effect that criterion arises from." Dr Ray Challen, "Transcript: Public Forum: Tubridgi Pipeline System," OffGAR, 6 September 2000.

45 “The large, sparsely populated area of the Mid West Region has numerous remote mining operations. The provision of energy supplies to these remote

mine sites is generally by individual diesel power stations. These are a significant cost to the industry.

The other fuel source for electricity generation in remote areas is natural gas. In the short to medium-term it can be expected that many of the existing mines will continue to use diesel as the principal fuel for generation, with conversion to dual-fuel or natural gas when major overhauls or replacement are due.” SMEC Australia for the Department of Resources Development, “Mid West Regional Minerals Study”, June 2000, Executive Summary.

46

“5.2 Natural Gas for Downstream Processing

While the Mid West Region produces relatively small quantities of natural gas, it is traversed by several significant natural gas pipelines: the Dampier to Bunbury Natural Gas Pipeline; the Goldfields Gas Pipeline; the Parmelia Pipeline; and the Mid West Pipeline. These are shown at Figure 3, Section 2. Other pipelines are also being planned.

The region is strategically located across this developing latticework of natural gas pipelines and is well placed to benefit from these facilities in the future.

This ready availability of energy, when combined with the region's mineral resources, creates the potential for a large mineral-processing sector. The challenge for industry is to bring the two together: gas producers need to identify a major potential market before they will commit to development; while mineral processors want guaranteed competitive energy supplies before they will commit to development. This situation can be overcome with some government facilitation.

The State Government is uniquely placed to take the first step by considering how the development of a large power station in the region can be linked to resource processing. If a private power generator were able to commit to the supply of power at a competitive price, this would act as a catalyst in encouraging mineral processors to examine opportunities. The State Government can, where such possibilities exist, investigate how such an outcome might be achieved.” SMEC Australia for the Department of Resources Development, “Mid West Regional Minerals Study”, June 2000, Executive Summary.

47

“4.2.3 Submissions from Interested Parties

Inclusion of Additional Services in the Services Policy

- Normandy

GGT is offering only a forward Firm Service as the proposed Reference Service, and is also offering to negotiate Non-Reference Services. However, since the start of the GGT pipeline, other services

(Interruptible Service, Parking Service and Authorised Imbalance Service) have been offered. GGT advances no reasons for these to be discontinued and Normandy believe that they should continue to be offered.” Draft Decision: Access Arrangement: Goldfields Gas Pipeline, OffGAR, 10 April 2001, section 4.2.3, page B-28.

48 For example: “Decisions about optimal levels of interconnection investment require resolution of the issue of the future direction of the market. By and large policy-makers don’t need to get involved in decisions about whether new factories are built to ensure we are adequately housed, clothed and fed. Sure, I know electricity is different, but I nevertheless believe we should be aiming to get to the point where policy-makers don’t need to worry about whether new interconnectors get built. Those decisions should be internalised within the industry.” Presentation: Overall, Has Deregulation Worked? - Australian Perspective, Rod Shogren, Commissioner, ACCC, 12 March 2002, Page 10.

49 “The point to emphasise is that the prospect of market power is what motivates firms to innovate and new firms to enter markets. Such transitory market power is not inimical to competition. Rather, it invites it.” Presentation: The ‘baby and the bath water’: avoiding efficiency mishaps in regulating monopoly infrastructure, Gary Banks, Chairman, Productivity Commission, 5 July 2002, page 4.

50 "It is of some relevance to notice, however, that as a competitive market, in this sense of an economist's understanding of a workably competitive market, is not a fixed and immutable condition with any absolute or precise qualities, but a process which involves rivalrous market behaviour: *Re Queensland Cooperative Milling Association Limited*. As such, a workably competitive market will react over time and according to the nature and degree of various forces that are happening within the market. There may well be a degree of tolerance of changing pressures or unusual circumstances before there is a market reaction. The expert evidence and writings tendered in evidence suggest that a workably competitive market may well tolerate a degree of market power, even over a prolonged period. The underlying theory and expectation of economists, however, is that with workable competition market forces will increase efficiency beyond that which could be achieved in a non-competitive market, although not necessarily achieving theoretically ideal efficiency." *Re Dr Ken Michael AM; Ex Parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231*, Supreme Court of Western Australia, 23 August 2002, page 60.

51 The ultimate guidance as to the objects and implementation of the Code has been established in principle as being revealed by the preamble, thus: "There is, however, one significant exception to this general tentative proposition which should be stated immediately. The last paragraph of s 8.1 recognises that the objectives (a) to (f) in s 8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may determine the manner in which they can best be reconciled or which of them should prevail. Contrary to the submissions of the Regulator and Alinta, the

discretionary task of seeking to reconcile conflicting objectives within s 8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s 8.1 itself. Of necessity, the Regulator must have guidance outside of s 8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s 2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s 8.1 the Regulator should take into account the factors in s 2.24(a) to (g). I will return to the implications of this later in these reasons. Were that not so, inevitably the Regulator would need to have regard to the general scope and objects of the Act, as revealed by the preamble, [emphasis added] in exercising the discretions contemplated by the last paragraph of s 8.1." Re Dr Ken Michael AM; Ex Parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, Supreme Court of Western Australia, 23 August 2002, page 40.

52 "It is convenient to restate the access criteria as set out in the preamble to the Act, and the introduction to the Code. They were:

- “(a) facilitates the development and operation of a national market for natural gas; and
- (b) prevents abuse of monopoly power; and
- (c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders; and
- (d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for the owners and operators of gas transmission and distribution pipelines and persons wishing to use the services of those pipelines; and
- (e) provides for resolution of disputes.”

Re Dr Ken Michael AM; Ex Parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, Supreme Court of Western Australia, 23 August 2002, page 45.

53 “In conducting his analysis (on risk), the Regulator may wish to consider the following issues in addition to the matters raised by the GGT:

- ...
- With its limited capacity and location the second pipeline (the Mid West pipeline) would only be able to compete for a limited part of the GGT market. Pipeline on pipeline competition exists for a number of pipeline systems.
- ...

-
- Whether competition from alternative fuels can be claimed to constitute a "unique" business risk for the pipeline. For example the transmission pipelines supplying the South West of the State are facing competition from LPG and electricity. Treasury, Office of Energy and Department of Resources in Draft Decision: Access Arrangement: Goldfields gas Pipeline, OffGAR, 10 April 2001, section 5.7.8, page B-140.

54

"The Magnesium project is a prime example. The development of GEMM now allows Anaconda to consider delivered gas prices of A\$3.00/GJ to A\$3.50/GJ into the North Eastern Goldfields region.

The establishment of these prices is of major regional significance for all developing projects. Critical to a competitive environment is energy pricing and the development of alternative supply sources.

Anaconda has been granted pipeline licenses for both a Northern and Southern route option, with work to commence shortly to obtain the necessary tenure for the preferred Northern option. The pipeline is required to traverse some 590kms to the Mt Margaret Project, and then onward to Murrin Murrin. A slight route adjustment is being considered which will provide a substantial reduction on distance, and therefore on pipeline economics.

Mt Margaret has a preliminary requirement for some 60TJ/day of gas, which provides a suitable base load for the development of the pipeline. The pipeline will therefore be constructed to match the Mt Margaret development timetable, and therefore construction is not expected to commence until January 2002 to match Mt Margaret commissioning commencement." Third Quarter Activities & Cashflow Reports, Anaconda Nickel Limited, 28 April 2000.

55

"GERALDTON TO MT MARGARET GAS PIPELINE

Consequent to the successful grant of the major pipeline licence grant of the Geraldton to Mount Margaret ("GEMM") from the Epic owned Dampier to Perth/Bunbury major line, the licence application for the GEMM pipeline extension to Murrin Murrin was also submitted during the quarter. This pipeline will enable the benefits of cheaper gas tariffs through the GEMM to be available to Murrin Murrin. Ongoing discussions are being held with the Department of Minerals and Energy to finalise the pipeline licence. It is expected that the licence will be granted during the first quarter of 2001.

Preliminary work on the central infrastructure corridor connecting the Oakajee Industrial Estate (Geraldton) to the Northern Goldfields region commenced during the quarter. Worley Limited are finalising the first phase of study for the state government and the final report is expected out in the first quarter of 2001. This corridor, once selected, will further boost the Anaconda plans for the GEMM pipeline and its extension." Second Quarter Activities and Cashflow Report, Anaconda Nickel Limited, 25 January 2001.

56 "GERALDTON TO MT MARGARET GAS PIPELINE ("GEMM")

The initial concept of GEMM was to provide lower gas prices into the Goldfields region than those available through the Goldfields Gas Transmission Line ("GGT")

The Office of Gas Regulation ("OffGAR") has recently released their draft decision on those Tariffs on the GGT, which require further reductions of 30% on current reference Tariffs for transporting gas through the GGT. ...

These substantial reductions make the development of GEMM less viable, though with a suitable baseload it remains competitive to the reduced GGT tariffs. Anaconda remains of the view that the regional loads in the North Eastern Goldfields will ultimately lead to the requirement for a second pipeline into the region, and it will therefore continue to maintain its Pipeline licence and development plans for GEMM." Third Quarter Activities & Cashflow Report, Anaconda Nickel Limited, 1 May 2001.

57 "In addition, the GPWG [i.e. the State Government's Gas Pipeline Working Group] is looking at establishing a corridor to facilitate the establishment of a lateral pipeline and other general infrastructure, running from Geraldton to the north eastern Goldfields. A future pipeline could join the DBNGP north of Geraldton and run 580km eastward to a point near Anaconda Nickel's proposed Mount Margaret nickel project, north of Leonora. The GPWG has commenced environmental, flora and fauna, geotechnical and Aboriginal heritage studies and surveys. A corridor width of 450 metres is proposed and the exercise is due for completion by the end of 2002." Prospect Magazine, Department of Minerals and Petroleum Resources, Government of Western Australia, September-November 2001, page 22.

58 For example:
"Gas (for power generation) – Geraldton to Murrin Murrin (GEMM) Gas Pipeline

Anaconda has secured Petroleum Pipeline Licences for two alternative alignments to construct a major spur from the existing "Dampier to Bunbury" Epic gas pipeline with a take-off east of Geraldton, to the Leinster/Leonora area and on towards Laverton, with a logical final alignment lying within the State Government's third party infrastructure corridor. The GEMM will provide competitively priced gas for the production of cheaper power to Anaconda and other consumers in the region." Anaconda Nickel Limited, Annual Report 2001, September 2001, page 13.

59 "Building Projects and Stimulating Regional Growth

Beyond Murrin Murrin, development of additional regional infrastructure focused on the North East Goldfields is critical to deliver significant economic and social benefits equally for the bush and all Australians. It is now recognised by government and industry alike that regional infrastructure is a

catalyst for new development projects that would otherwise not progress past initial feasibility studies.

In the region, Anaconda has been working for more than two and a half years with major industry participants and the Federal and Western Australian Governments to achieve greater regional infrastructure. Infrastructure will catalyse the development of a suite of mineral processing projects, the financing of which will underwrite government sponsorship. Independent Government sponsored cost-benefit studies have endorsed this strategy.

Commencing these initiatives, the Western Australian State Government has committed to the development of a major infrastructure corridor from the Geraldton/Oakajee region through to the North-East Goldfields to accommodate gas and water pipelines, fibre optic cables and rail.” Anaconda Nickel Limited, Annual Report 2001, September 2001, page 12.

60 “The collective impact of substitution possibilities.

Second, the availability of substitutes limits the exercise of market power. For example, rail track providers may be sole suppliers but, for most freight or other services, they face intense competition from other transport modes, notably road.” Presentation: The ‘baby and the bath water’: avoiding efficiency mishaps in regulating monopoly infrastructure, Gary Banks, Chairman, Productivity Commission, 5 July 2002, page 4.

61 "I congratulate the joint venture companies which will take part in this project. The parent companies - Western Mining Corporation Ltd, Normandy Poseidon Ltd and Broken Hill Proprietary Co Ltd. - have shown a lot of bravery, a lot of guts - if I can use that good old fashioned word - a lot of vision, and a lot of entrepreneurship in deciding to proceed with this project. They will put in place some basic and essential infrastructure for industry to develop in the centre of this continent. If decentralisation is to go ahead this sort of basic infrastructure needs to be developed." Mr. Grill (Eyre), Hansard, 6 April 1994, page 11522, Second reading.

62 “If tariffs on pipeline access are set too high, there is a direct transfer of wealth from consumers to the asset owners; if too low, the asset will not be maintained and investment plans will be dropped.” Allan Fels, Business Review Weekly, June 20-26 2002, page 26.

63 "What lies ahead

The need for policy reform has been discussed in many other forums. The contractual options for addressing regulatory risk are two fold.

First, regulatory risk can be passed downstream to gas users. This would probably be an acceptable outcome from the pipeliner's point of view. However, the clients I represent will not accept the risk of being stranded with high cost transmission contracts when competitors [who are existing users]

are awarded access to the same assets at a lower cost. This very situation has been the outcome of our current regulatory process.

Second, regulatory risk can be passed upstream to gas producers. This outcome may meet the commercial needs to pipeline companies and, in some instances, it will also be acceptable to gas producers. I must ask, however, is it the intention of regulators and gas users to deliver increased market power to gas producers in this way?

It is my plea to this important industry body to consider whether the gas transmission pipeline industry deserves the opportunity to offer open access services on a commercially viable gas pipeline system. I contend that that is where all of our best interests rest. ..." "Major Planned Pipeline Extensions", Presentation by Mike Lauer to the 2001 AGA Convention, 16 November 2001, "What lies ahead".

64 "Mr Kolf said that differing interpretations of the gas access code were a source of delays and disputes, and that parties most affected by an access decision would be the ones to test a new code in detail. Litigation could be necessary and helpful, Mr Kolf said, whenever the interpretation of phrases containing the word 'normally' came into dispute and required specific determination." Regulator talks on gas access, Peter Kolf (Executive Director, OffGAR), WA Business News, 8 August 2002, page 14.

65 **"6. The nation's future energy market: a first-best approach**

We now need to develop clear, future directions.

A first-best approach is to develop an integrated energy market.

For both gas and electricity investment - that is responsive to users needs - is essential. Investment is vital to the development of an interconnected market and systems security in both gas and electricity.

In electricity the most urgent need is to develop greater demand-side responsiveness. That is, extreme inelasticity of demand simultaneously makes wholesale prices particularly volatile and enables generators to wield strong market power, especially during times of tight supply and demand.

The second market completion imperative is getting price signals to drive decisions about network augmentation, generation and load location, and interconnection, to have investment decisions made in an integrated, consistent manner. How should that integration be provided? By price signals, not by central planning." "Efficient energy markets: The ACCC, competition and regulatory issues; Speech to Inaugural Conference of Energy Users' Association of Australia", Allen Fels, Chairman, ACCC, 19 November 2001, page 19.



GOLDFIELDS GAS PIPELINE REVOCATION APPLICATION

ATTACHMENTS

**Submitted to the
National Competition Council**

March 2003

ATTACHMENT 1 : RELEVANT CHRONOLOGY

date	activity / event
1991-92	Australia-wide political trend begins to develop for pro-competition policies aimed at redressing purported deficiencies with penetration, accessibility and pricing in national gas markets.
Dec 1992	COAG discusses national gas reform.
April 1993	Western Australian Energy Board of Review tables its report entitled “The Energy Challenge for the 21 st Century” which proposes structural changes to the WA gas market, and SECWA in particular, along pro-competitive lines. Recommends light-handed regulation, with access, operating rules and pricing methods to be publicly disclosed, and disputes to be settled by an independent conciliator and arbitrator.
May 1993	Heads of Agreement for GGT Joint Venture signed by private consortium.
June 1993	COAG discusses national gas reform.
August 1993	Hilmer Committee publishes its “National Competition Policy” which sees government ownership and regulation, and access to key infrastructure assets as the major impediments to competition. Favours an approach whereby specific pricing principles would be stipulated, but access prices set by negotiation and disputes settled by arbitration.
Dec 1993	GGP Feasibility Study completed by private consortium.
Feb 1994	COAG discusses national gas reform – clear vision forming is a light handed regulatory framework with pipeline access on basis of individually negotiated arrangements and pricing.
23 Mar 1994	GGP State Agreement signed.
3 May 1994	Goldfields Gas Pipeline Agreement Act 1994 comes into effect, ratifying the Goldfields Gas Pipeline Agreement (the State Agreement). Government specifies minimum size of pipeline and requirement that its capacity be expandable by a minimum of 50% of initial capacity by means of additional compression.
June 1994	GGT Joint Venture agreement signed. Minimum load of 60TJ/day determined as viability threshold. ⁱ
1994	GGTJV offers third party “Open Season” ⁱⁱ (7.5% tariff discount for 5 years) but fails to gain additional foundation customers.
Sept 1994	Detailed Engineering on GGP commenced.
Nov 1994	GGT submits project proposals (including tariff setting principles) to the State Government under clause 9(1) of the

ⁱ Presentation : WMC’s Involvement in the Goldfields Gas Pipeline, John Harvey, Manager Energy Supply, WMC Resources, 12 March 2002.

ⁱⁱ The term “open season” refers to the defined period during which expressions of interest may be received, and clarification of capacity requirements and levels of commitment be undertaken. This information permits appropriate cost estimates to be made and hence indicative tariffs to be calculated.

	State Agreement.
Jan 1995	Western Australian Government approves State Agreement proposals and issues Pipeline Licence. Initial tariff schedule (agreed between Government and original vertically integrated GGP owners) known as “A1”.
June 1995	Gas Reform Task Force formed.
Sept 1995	GGP site construction begins.
Dec 1995	Gas Reform Task Force releases its first Scoping Study for the Code.
Jun/Sept 1996	GGP progressively commissioned to supply gas to mines belonging to WMC, Normandy and BHP (the original GGP owners).
4 Oct 1996	GGP officially opened. Displaces 140 MW of electrical generation capacity from the SWIS ⁱⁱⁱ as well as almost 300 million litres of diesel p.a. used in remote power generation. ^{iv}
Feb 1997	Task Force replaced by the Gas Reform Implementation Group. (First public consultations over the Code launched in July 1997)
1997	Third Party gas deliveries commence for mines located at Plutonic, Wiluna and Jundee, as well as for domestic consumption at Kalgoorlie.
Nov 1997	National Gas Pipeline Agreement (the Code) signed.
1998	Third Party gas deliveries commence for mines at Murrin Murrin and Cawse.
1998	State Government determines to establish independent regulator under the Code in order to “recognise the unique circumstances” existing in W.A. ¹
1 Mar 1998	Discounted “A2” tariff schedule comes into effect (termination date 31 December 1999). Represents 15% discount in conformance with GGT’s obligation under State Agreement to promote use of the pipeline.
2 nd half 1998	Drafting of legislative implementation of the Code in W.A. completed.
late 1998 - early 1999	Original owners, WMC & Normandy sell their shares of the GGP to Southern Cross Pipelines Australia and Southern Cross Pipelines (NPL) Australia respectively; BHP sells its share to Duke Energy International. All original owners establish and retain “grandfathered” gas transportation contracts and remain the main customer base of GGP. Third party contracts are unaffected.
9 Feb 1999	Gas Pipelines Access (Western Australia) Act 1998 (incorporating the National Third Party Access Code for Natural Gas Pipeline Systems) comes into effect. Terms of access under the pre-existing regulatory regime is specifically recognised in the Act as being “ an approved Access Arrangement under the Code until 1 January 2000” (when it was anticipated that the Code would have been implemented and would have assumed authority for the

ⁱⁱⁱ Electricity Demand Forecasts 1996-2005, Western Power, December 1995.

^{iv} Goldfields Gas Pipeline: Relevant Downstream Markets, Ventnor Consulting Group, August 2002, page 26.

	relevant aspects of regulated third party access).
1 Jul 1999	Further discounted "A3" tariff schedule (20% discount from A1) comes into effect (termination date 31 December 1999).
Sept/Oct 1999	"Economic Development Tariff" (EDT) publicly offered for new and expansion projects. Incrementally priced tariff to be determined once realised load and hence incremental cost of capacity that would be required are known.
15 Dec 1999	GGP Access Arrangement under the Code formally submitted. Proposed tariffs consistent with pre-existing price path and load growth philosophy.
Dec 1999	Anaconda release report "Kick-starting the New Millenium" containing details of proposed GEMM pipeline, including commissioning date of 2004. ^v
1 Jan 2000	Previously advertised "A4" discounted tariff schedule (25% discount from A1) comes into effect (no termination date specified). Discount is also offered to existing customers (all except for the one customer supplying gas for domestic use, accepting) but no <u>additional</u> load eventuates.
8 May 2000	The 360km long Mid West Gas Pipeline linking Windimurra to the DBNGP officially opened (gas had actually been flowing since August 1999).
10 Apr 2001	Regulator issues Draft Decision for GGP Access Arrangement.
Dec 2001	The "A4" Tariff discount is withdrawn.
1 st half 2002	Third Party contract for supply of gas to Esperance for power generation concluded.
23 Aug 2002	W.A. Supreme Court hands down decision that Regulator's DBNGP Draft Decision was flawed by errors of law and must be reconsidered. ^{vi}
6 Nov 2002	Regulator acknowledges GGP Draft Decision contains errors of law similar in nature to those identified by the Court in the DBNGP decision, and issues notice of intention to reconsider, amend and re-issue GGP Draft Decision in first stage of new 3-stage process prior to GGP Final Decision. ^{vii}

^v Kick-starting The New Millennium; Developing the Goldfields and Mid-West; "The Government's Choice", Anaconda Nickel Limited, December 1999.

^{vi} Dr Ken Michael AM; Ex Parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, Supreme Court of Western Australia, 23 August 2002.

^{vii} Notice: Proposed Access Arrangement for the Goldfields Gas Pipeline, Ken Michael, Acting Gas Access Regulator, Office of Gas Access Regulation, 6 November 2002.

NOTE(S) TO ATTACHMENT 1.

¹ "I asked what were the unique circumstances in Western Australia. We have only two transmission pipelines - the Dampier-Bunbury natural gas pipeline and the goldfields gas pipeline. The Office of Energy, in a briefing note to Hon Helen Hodgson, stated -

A local Regulator understands Western Australia's unique conditions. Such factors as low population density, resource development based economy, standard tariffs for residential and small business customers and regional development. An Eastern States regulator is more likely to be more familiar with higher population densities, gas markets where the majority of gas transported is sold to residential customers and single gas fields servicing pipelines. In particular, Eastern States gas transmission pipelines are unlikely to have access arrangements that allow a wide variety of services such as back haul."

Hon Mark Nevill, Hansard, 2 December 1998, page 4630, Gas Pipelines Access (Western Australia) Bill, Second reading.

PART A: CURRENT SITUATION

As previously discussed, the Goldfields Gas Pipeline (GGP) was established under the auspices of the Goldfields Gas Pipeline Agreement Act 1994 (the State Agreement). The State Agreement imposed a range of obligations both on the Joint Venturers and the Government. These obligations were designed to facilitate the construction and operation of the GGP. With respect to the ongoing operation of the GGP, the State Agreement establishes a clear commercial framework for the operation of the GGP. This framework covers, amongst other matters, the requirement for non-discriminatory open access to the pipeline together with the establishment of tariff setting principles and an associated benchmark tariff.

The requirements of the State Agreement are reflected in the GGP access documentation found on the GGT web-site (www.ggt.com.au). This comprehensive suite of documents includes copies of the:

- Guide to New Gas Users;
- Terms and conditions;
- Tariff Setting Principles;
- Statement of Tariffs and Charges; and
- Applicable Terms and Order Forms.

The State Agreement provides a comprehensive, flexible, framework for negotiating access to the GGT in a manner consistent with the CoAG competition principles. Detailed below are a number of the key requirements of the State Agreement with respect to access that indicate how this framework currently applies. These include requirements for:

Clause 19 - Promotion of gas transmission market growth

Clause 19 of the State Agreement requires that “the Joint Venturers shall actively promote, and cause any operator of the Pipeline to actively promote, use of the Pipeline by Third Parties and shall pursue growth in the market for gas transmission through the Pipeline...”

Clause 20 - Provisions for Access to Pipeline and Pipeline expansion

The various sub-clauses of clause 20 of the State Agreement require the Joint Venturers to, amongst other things:

provide “...non-discriminatory Third Party access to such capacity, including Developable Capacity, of the Pipeline as may from time to time not be contracted or utilised...”. In this context, non-discriminatory access requires that all third parties seeking access at any particular time must be provided with substantially the same access information and that no third party will be disadvantaged compared to any other third party as a result of information provided. Further, any differences in access rights and tariffs offered to third parties from time to time must be substantially attributable to differences in customer requirements

together with the times and circumstances under which individual agreements are negotiated.

“...use all reasonable endeavours to develop the capacity of the Pipeline (including the installation of additional compressor stations and looping of the Pipeline) as may be necessary from time to time to accommodate the requirements of Third Parties wishing to transmit gas through the Pipeline...”.

“...at the cost of the relevant Third Party, undertake the connection to the Pipeline of a lateral pipeline for any Third Party reasonably requiring such connection...”

Clause 20 also provides a mechanism for binding independent arbitration of access disputes covering both existing and developable capacity. The fundamental principle applying to arbitration under the State Agreement is that the owners must provide access on fair and reasonable terms to all existing and developable capacity where it is technically and economically feasible to do so.

Clause 22 – Tariffs

The various sub-clauses of clause 22 of the State Agreement establish the basis on which tariff for access to pipeline services will be calculated. In particular, tariffs must be “fair and reasonable and consistent with the tariff setting principles approved by the Minister...”. Further the Joint Venturers are obliged to establish and make available an “Indicative Tariff Schedule” based on the tariff setting principles approved by the Minister.

Tariff Setting Principles

Broadly, the 13 principles detailed in the Tariff Setting Principles have the following aims, to:

- promote the use of the pipeline;
- provide a commercial rate of return to the owners *“on all project capital, including all costs reasonably incurred in the construction and operation of the pipeline and to recover all reasonable pipeline operating, maintenance and administration costs”*;
- categorise users on the basis of the nature and duration of the service they are seeking;
- be non-discriminatory between similar category customers;
- allow for the owners to require credit support;
- allow for a minimum invoice charge;
- require the tariff structure to include a capacity reservation component and a throughput component with the overarching aim of promoting the utilisation of reserved capacity;
- require the tariff structure to recover the capital cost of the pipeline equitably over time;
- allow for tariffs to be differentiated on the basis of key service characteristics such as distance, contract term, service priority etc.

- require all firm transportation tariffs to be set by reference to the Benchmark Tariff;
- set the maximum contract term to be 20 years;
- provide a mechanism for redetermining tariffs where they are not consistent with the principles; and
- allow for the owners to set tariffs equal to or less than those resulting from the application of principle 2 subject to compliance with these principles.

Summary – Current Situation

Access to the GGP is currently provided under the auspices of the State Agreement and associated Tariff Setting Principles. Taken together, these provide a comprehensive platform for providing un-restricted, non-discriminatory open access on a commercial basis to the services provided by the GGP.

PART B: PROPOSED BASIS FOR PROVISION OF ACCESS ON THE GGP AS AN UNCOVERED PIPELINE

In circumstances where GGT is operating the GGP as an uncovered pipeline, GGT is both committed and legally obliged to continuing to provide access on a basis consistent with the arrangements under the State Agreement and the associated Tariff Setting Principles. In addition, GGT is committed to adopting a voluntary set of business principles to explicitly govern its behaviour and which are consistent with, and an enhancement of, the access arrangements currently prevailing. This is based around the following six principles.

- developing market-responsive pipeline services;
- the use of non-discriminatory tariffs;
- public disclosure of dealings with affiliates;
- public disclosure of key contract details;
- protection of confidential information;
- binding independent dispute resolution process.

These principles are briefly discussed below.

Principle 1 – Market-responsive Pipeline Services

Intent

To develop and promote effective pipeline services in conjunction with market participants and in response to market needs. Key elements include ensuring:

timely response to customers needs; and
publicising available pipeline capacity and services information.

General Discussion

This principle requires timely responses that meet reasonable customer expectations while being practically achievable. This will, at least in part, be

achieved by ensuring initial notification to customers indicating the likely time frame for finalising a response. This principle also ensures that customers have ready access to all relevant information as to current service offerings and available pipeline capacity. Effective application of this principle will mean that customers receive the high level of service which is expected in competitive markets.

Principle 2 - Non-Discriminatory Tariffs

Intent

To ensure that all customers can be confident that they can access a given service offering for the same tariff as other customers. That is, all prospective third party customers will have access to the same tariff for the same service. The determination of same service will include consideration of the currency of the service offering (i.e. whether the service offering is still valid) and factors such as the following:

- the term of the contract;
- the transportation path, including direction of flow;
- the service priority;
- load profile;
- presence of a price link; and
- other factors which may materially impact on the financial risk of the parties.

Tariff differentiation related to factors such as the type of customer, type of gas, or volume of gas, will not take place.

General Discussion

This principle provides all customers with the confidence that, regardless of the size of their custom, they will be able to access the same service for the same price as that enjoyed by the very largest customers. As the largest pipeline customers have significant negotiating power, this ensures that all customers may be confident of accessing the very best available terms and conditions.

Principle 3 - Disclosure of Dealings with Affiliates

Intent

To promote transparency in the market by assuring all participants that there is no preferential treatment of affiliated companies. This will be achieved by ensuring that the key characteristics of all service contracts with an affiliated entity are made public. In addition, the same service offering will be made available to any other interested party.

General Discussion

All affiliate deals will be posted on the web site in a manner that provides sufficient detail for customers to be able to accept an offer for a similar service. This is consistent with the non-discriminatory tariff principle (Principle 2) and also consistent with disclosure of non-affiliate arrangements discussed

in Principle 4. In addition, disclosure under this principle will involve clear indication that the counterparty to the contract is an affiliate. Customers can therefore be certain that they can access pipeline services on terms and conditions at least as advantageous as those gained by affiliate companies.

Principle 4 - Disclosure of Key Contract Details

Intent

To assure all market participants of the non-discriminatory nature of GGT's service offerings by ensuring ready and equal access to key service information. This will be undertaken by ensuring that key characteristics of all service contracts are made public. This will include at least the defining characteristics of same service as discussed in Principle 2.

General Discussion

The main difference between Principles 3 and 4 is that disclosure of non-affiliate deals will not disclose the identity of the counterparty. Service offerings will remain posted while the offer is current. In general this will mean a minimum of three months for service offerings with a term of 1 year or greater and a minimum of 1 week (although potentially much longer) for service offerings with shorter terms. This principle aims to increase transparency in the market and provide assurance to customers that they can access services at a competitive price.

Principle 5 – Protection of confidential information

Intent

To provide customers with certainty that confidential commercial information will only be used for the purposes for which it was provided.

General Discussion

This principle specifically addresses GGT's commitment to ensuring that customers can provide the pipeline operations company with any and all commercial information with absolute certainty that that information will not be passed on or used for any purpose other than the purpose for which it was provided. GGT will ensure that effective systems are in place that guarantee that only designated employees will be able to access confidential information.

Principle 6 - Binding Independent Dispute Resolution

Intent

To provide all customers or prospective customers with the confidence that in the event of a dispute related to this policy that they are unable to have settled to their satisfaction via negotiation, they would have access to timely and binding independent arbitration.

General Discussion

This principle provides assurance to all customers that in the event of a non-discriminatory access dispute, GGT will commit to binding arbitration. This reflects GGT's belief in the benefits to GGT's customers associated with this voluntary behavioural approach to pipeline access.

Summary – Proposed basis for providing Access absent Coverage

Under GGT's proposed basis for the provision of access in circumstances where the GGP is an uncovered pipeline, users and prospective users will be provided with the certainty that they can access services in a manner consistent with that currently applying under the State Agreement and associated Tariff Setting Principles. In addition, GGT will commit to the adoption of a set of business principles that aim to ensure that management of the pipeline is undertaken with the maximum possible level of transparency with respect to access issues and which is completely customer focussed. This degree of customer focus, and the market driven responsiveness which it engenders, is impossible under the Code wherein many instances the Regulator is interposed between the service provider and the customer.

ATTACHMENT 3 : GAS RESERVES IN WESTERN AUSTRALIA

Reserves as at 31 December 2001

ref. "Petroleum in Western Australia", Department of Mineral and Petroleum Resources, April 2002

Producing Reserves

Basin	Gas 90%	Gas 50%
Perth	1.30	2.75
Carnarvon	448.45	522.41
Canning	0.00	0.00
Browse	0.00	0.00
Bonaparte	0.09	0.08
Totals (Gm³)	449.84	525.23

Basin	Gas 90%	Gas 50%
Perth	0.05	0.10
Carnarvon	15.83	18.44
Canning	0.00	0.00
Browse	0.00	0.00
Bonaparte	0.00	0.00
Totals (Tcf)	15.88	18.54

Category 1

Potential for Short Term Development

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	64.11	93.89
Canning	0.00	0.00
Browse	0.00	0.00
Bonaparte	0.00	0.00
Totals (Gm³)	64.11	93.89

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	2.26	3.31
Canning	0.00	0.00
Browse	0.00	0.00
Bonaparte	0.00	0.00
Totals (Tcf)	2.26	3.31

Category 2

Expected Medium to Long Term Development

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	72.89	134.32
Canning	0.00	0.00
Browse	356.79	586.16
Bonaparte	0.00	0.00
Totals (Gm³)	429.68	720.48

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	2.57	4.74
Canning	0.00	0.00
Browse	12.59	20.69
Bonaparte	0.00	0.00
Totals (Tcf)	15.17	25.43

Category 3

Not Currently Viable - held under Retention Lease

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	890.07	1133.92
Canning	0.00	0.00
Browse	0.00	0.00
Bonaparte	9.91	11.76
Totals (Gm³)	899.98	1145.68

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	31.42	40.03
Canning	0.00	0.00
Browse	0.00	0.00
Bonaparte	0.35	0.42
Totals (Tcf)	31.77	40.44

Summary Total for Undeveloped Reserves (Category 1+2+3)

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	1027.07	1362.13
Canning	0.00	0.00
Browse	356.79	586.16
Bonaparte	9.91	11.76
Totals (Gm³)	1393.77	1960.05

Basin	Gas 90%	Gas 50%
Perth	0.00	0.00
Carnarvon	36.26	48.08
Canning	0.00	0.00
Browse	12.59	20.69
Bonaparte	0.35	0.42
Totals (Tcf)	49.20	69.19

Summary Total

Basin	Gas 90%	Gas 50%
Perth	1.30	2.75
Carnarvon	1475.52	1884.53
Canning	0.00	0.00
Browse	356.79	586.16
Bonaparte	10.00	11.84
Totals (Gm³)	1843.60	2485.28

Basin	Gas 90%	Gas 50%
Perth	0.05	0.10
Carnarvon	52.09	66.52
Canning	0.00	0.00
Browse	12.59	20.69
Bonaparte	0.35	0.42
Totals (Tcf)	65.08	87.73

ATTACHMENT 4 : DETAILED SUMMARY OF DOWNSTREAM MARKET ANALYSIS

In its report entitled “Goldfields Gas Pipeline – Relevant Downstream Markets”, Ventnor Consulting Group (Ventnor) has identified the existing shippers on the GGP. The State Agreement distinguishes between “Initial Customers” – who made commitments to pipeline capacity prior to the construction of the GGP – and third parties other than Initial Customers.

The Initial Customers were the original developers and owners of the GGP. Their respective operations are summarised below:

- ***BHP Iron Ore – Newman Operations***

Newman is BHP Iron Ore’s largest iron ore mining operation, producing approximately 30 Mt/a. Gas is used for the generation of electricity for mining and support operations and replaced diesel fired generation in 1996.

- ***WMC Limited***

Mt Keith Operations

Mt Keith is a large open cut nickel mine commissioned in 1994. Ore is processed to produce 48,000 t/a of nickel in a 20% concentrate. Gas is used for the generation of electricity for mining and processing operations. The original diesel generating plant was replaced in 1996.

Leinster Operations

Nickel mining at Leinster dates back to the late 1970’s. WMC purchased the operations in 1989. Mining is primarily underground and the ore is processed to produce 40,000 t/a of nickel in a 12% concentrate. As with Mt Keith gas replaced diesel generation, with the electricity being used for mining and process purposes. Until recently WMC also owned and operated the Agnew gold mine in the vicinity. This mine was sold recently, but continues to draw its power requirements from the Leinster power station, as does the Lawlers Mine which converted from diesel in 2001.

Kalgoorlie Nickel Operations

WMC has mined nickel at Kambalda (50 km south of Kalgoorlie) since 1967. It has divested its mining operations recently to smaller companies, but continues to process their ore in its Kambalda Nickel Concentrator. Concentrates from Kalgoorlie, Leinster and Mt Keith are further processed to a matte containing 72% nickel in WMC's Kalgoorlie Nickel Smelter. Gas is shipped from the GGP via a lateral and is used primarily for power generation, which replaced electricity previously purchased from Western Power and supplied via 220 kV transmission line from Muja Power Station at Collie.

Kwinana Nickel Refinery

Matte from the Kalgoorlie Nickel Smelter is further refined at Kwinana to produce pure nickel metal. WMC has operated the Kwinana Nickel Refinery since 1970. The electricity requirements of the refinery have, since 1996 been supplied through the state grid from the Kalgoorlie generating facilities established by WMC, replacing power originally supplied by Western Power.

- ***Normandy Mining (now Newmont)***

Jundee Operations

The Jundee gold mine commenced operations in 1995. Its power requirements were originally supplied from diesel generators, which were replaced with gas when Normandy acquired a strategic interest in 1997.

Wiluna Mines

As with Jundee, the Wiluna gold mine converted from diesel to gas generation in 1997.

Kalgoorlie Operations

With the closure of the Mt Charlotte and Kaltails operations, the Kalgoorlie Superpit (50% Normandy) is Normandy's one remaining operation in Kalgoorlie. Electricity previously purchased from Western Power – is now generated in a gas fired power station owned jointly with TransAlta.

While no third parties took up the original owners' offer of pre-construction discounts, a number have since negotiated transmission contracts. These are summarised below:

- ***Plutonic Mine***

The Plutonic Gold Mine commenced operations in 1990. Power was originally supplied from company owned diesel generators, which were replaced with gas fired generators in 1997.

- ***Anaconda – Murrin Murrin Operations***

The Murrin Murrin nickel project commenced commissioning in December 1999, but is still operating well below design capacity. Gas is used for electricity generation, and for the production of hydrogen.

- ***Cawse Nickel***

Cawse produced its first nickel in 1999 but its owner Centaur was placed into administration in 2001. The operations have since been purchased by the OM Group. A gas-fired cogeneration plant provides power and steam for the operation.

- ***AlintaGas***

AlintaGas commenced reticulation of natural gas within the Kalgoorlie-Boulder area in 1997/98. Competition is provided by LPG.

- ***Esperance Power***

On 28 February 2003 it was announced that Burns and Roe Worley would shortly commence work on the development of a new gas fired power station to replace diesel generation in Esperance, and a new 330 km gas pipeline from Kambalda to supply gas sourced from the north west of the state.

Individual contracts for GGP transmission capacity are confidential, however a submission by GGT to the Acting Gas Access Regulator shows:

- MDQ commitments for the GGP dropping from 108.4 TJ/d in 2000 to 98.2 TJ/d by 2006;
- throughput increasing from 77.4 TJ/d in 2000 to 80.6 TJ/d in 2006.

Office of Energy information on contracted gas supplies provides the following breakdown of gas supply commitments by each of the major GGP shippers:

<u>Initial Customers</u>	<u>TJ/d</u>
BHP-Newman	7.0
WMC	37.0
Normandy	<u>18.5</u>
	62.5
<u>Third Parties</u>	
Plutonic	3.0
Anaconda	13.0
Cawse	4.5
AlintaGas	<u>0.5</u>
	21.0
Total	83.5

These figures correlate closely with GGT's recent throughput outlook, and provide a good demonstration of the low level of third party sales compared to the level of commitments provided by the original developers of the GGP. Ventnor^{viii} has estimated that except for 6-7 TJ/d, all gas is used for the generation of electricity.

From the preceding information on the nature of the operations supplied by the GGP, Ventnor has identified a number of downstream markets where increased access to the GGP might be seen to potentially promote competition. These are as follows:

- ***the market for gas*** – for applications requiring gas for its inherent qualities;
- ***the market for electricity*** – Ventnor suggests that consideration of the electricity market needs to be separated into “stand-alone” or remote generation, and electricity generation which is connected to the Western Power grid;
- ***the market for energy for remote electricity generation*** – specifically along the route of the GGP;
- ***the market for iron ore*** – an international market;
- ***the market for nickel*** – an international market;
- ***the market for gold*** – an international market;
- ***a prospective market for large scale chemical processing.***

In considering the requirements of Coverage Criterion (a) it is important to remember that in the absence of Coverage, the GGP remains subject to the access regime established pursuant to the State Agreement. The relevant test is not, therefore, whether access to the GGP would promote competition in particular downstream markets. Third party access clearly exists under the

^{viii} Goldfields Gas Pipeline: Relevant Downstream Markets, Ventnor Consulting Group, March 2003, page 21.

State Agreement, and has existed since the initial establishment of the GGP. In view of the absence of disputes over access, with either the State or third parties, or unresolved access negotiations, GGT would argue that the State Agreement regime has been demonstrably effective.

Clearly the relevant question is whether any increased access which might result from Coverage under the Code would promote competition in a particular downstream market. Ventnor's conclusions in respect to each of the potential markets listed above are summarised below:

– ***Market for Gas***

- “Natural gas has limited use along the GGP corridor for its inherent qualities (less than 10% of GGP throughput), whether for process applications or domestic use;
- There is a strong and competitive market for LPG (in bulk or bottled form), which provides an effective alternative to natural gas;
- AlintaGas' decision to reticulate natural gas in the Kalgoorlie-Boulder area was made in 1996/97, under the State Agreement access regime;
- The transport component comprises less than 20% of AlintaGas published tariffs for Kalgoorlie-Boulder, which are not out of line with tariffs for the Perth metropolitan area;
- The GGP does not appear able to significantly influence the market in respect to gas delivered for use as gas within the Kalgoorlie-Boulder area;
- It is difficult to see how the Code might increase access or how any such increased access to the GGP might promote competition in the gas market along the GGP corridor”.

– ***Market for Electricity for Remote Ventures***

- “Electricity generated for remote mining and processing ventures is, in the main, captive to the mines and companies served;
- Gold Fields' Agnew Gold Mine was previously owned by WMC and continues to be supplied by the Leinster Power Station;
- Barrick Gold's Lawlers Mine commenced purchases of electricity from Southern Cross Energy in 2001. This decision does not appear to have any relationship with GGP coverage under the Code in 2000;
- Decisions to adopt gas fired generation – with the exception of the Lawlers Mine – were made under the State Agreement access regime prior to 2000;
- Gas transported by the GGP does not supply a substantial number of the remote ventures within reasonable proximity to the GGP;
- In Ventnor's view it is hard, in any event, to categorise the generation of electricity for remote mining and processing projects as a market in which competition might be promoted by increased access to the GGP”.

– **Market for Electricity Connected to the Western Power Grid**

- “Western Power previously supplied the bulk of the power requirements now met by SCE and GP in the Kalgoorlie/Kambalda area;
- Electricity generated by SCE and GP in the Kalgoorlie/Kambalda area can be regarded as part of the wider SWIS electricity market;
- Surplus electricity transmission capacity exists between Kalgoorlie/Kambalda and Western Power’s Muja power station which would enable bulk power supply in either direction;
- The SCE and GP generation facilities were developed at a time when SECWA/Western Power was a vertically integrated electricity monopoly;
- Reform and deregulation in the electricity industry is likely to see serious competition in generation and a move to full retail competition within the SWIS market;
- The costs of gas fired generation in Kwinana (or other locations in proximity to the DBNGP) will be significantly lower than those of SCE and GP, notwithstanding any tariff reductions which GGT might implement;
- The GGP – and the SCE and GP generation facilities in the Kalgoorlie-Boulder area – do not appear able to significantly influence the market in relation to the SWIS electricity market;
- Decisions by WMC and Normandy to develop gas fired generation in the Kalgoorlie/Kambalda area were made in the context of the State Agreement negotiations before the GGP was constructed;
- Third party electricity consumers have been supplied by SCE and GP under existing arrangements, but at marginal prices;
- Increased access to the GGP will not in Ventnor’s view lead to the promotion of electricity competition within the SWIS”.

– **Market for Energy for Remote Electricity Generation**

Ventnor identifies a number of factors – in addition to delivered energy cost – which companies must consider in making a decision between gas and diesel fired electricity generation. These include:

- Lengthy take-or-pay commitments for gas supply, compared to diesel which can be purchased on shorter-term and more flexible arrangements;
- Take-or-pay commitments for gas transmission, as well as substantial price incentives for longer term contracts;
- The need for gas supply and transmission contracts to cover peak requirements, in comparison to diesel which can be stored at low cost to cover daily, weekly or seasonal load fluctuations;
- The capital cost involved in constructing a gas lateral to the operation concerned;
- The higher capital cost – and lower salvage value – of gas fired generating plant compared with diesel plant, particularly if provision has to be made for dual fuel firing for security reasons;

- The uncertainties facing the operation in terms of economic mining reserves, commodity prices and exchange rates;
- The financial capacity of companies – often with low capitalisation – to support the higher capital costs and take-or-pay commitments associated with gas;
- The level of specialised professional support required to implement and manage the more complex contractual arrangements required;
- Risks associated with supply interruption.

Ventnor estimates that 11.3 PJ/a of diesel has been displaced by gas in those operations which have converted to gas fired electricity. This compares with total uses of petroleum products in Western Australia for 1999/2000 of 207 PJ (transport services and storage – 144 PJ; primary and secondary industry – 58 PJ).

Ventnor reaches the following conclusions with respect to the market for energy for remote electricity development:

- “A market for energy specifically for remote electricity generation exists along the GGP corridor. There is competition between gas and diesel fuel for this market;
- The GGP has substantial unused (developable) capacity and there is, as a result, a strong incentive for the joint venturers to promote additional throughput;
- The diesel market itself is a large and highly competitive market in Western Australia. Competition from gas for remote electricity generation will have little if any impact on this market as it comprises a relatively small proportion of total diesel use;
- The choice between gas and diesel as the fuel for remote electricity generation depends on a number of cost elements – only one of which is gas transmission – and a variety of other factors related to financial risk, complexity and anticipated length of operation;
- In view of the fact that there are still a significant number of diesel operated stations within the GGP corridor – some quite recent - diesel generation still represents a serious option for many remote mining and processing operations;
- All except one of the remote operations which selected gas fired generation did so under the State Agreement access regime, and well before coverage of the GGP under the Code;
- In Ventnor’s view it is unlikely that increased access to the GGP – even if it could be shown that the Code could increase access beyond that provided under the State Agreement – will, of itself, lead to the promotion of competition in the market for energy for remote electricity generation”.

– **Market for Iron Ore**

- “Western Australia and Brazil are the dominant players in the international iron ore business. Western Australia’s share of market production has increased from 10% to 17% over the last 10 years;
- Western Australia has the lowest iron ore production costs in the world;
- BHP Iron Ore supplied 68.5 Mt out of a total of 163.1 Mt produced in Western Australia in 2001. Of this 30.4 Mt was produced by its Newman operations;
- Shipments of Western Australian iron ore have grown rapidly during the period in which the GGP has been in operation – i.e. from 133.7 Mt in 1996 to 163.1 Mt in 2001;
- The export value of iron ore from BHP Iron Ore’s Newman operations is in the order of \$970 million (as a proportion of export value of \$5.2 billion in 2001);
- The costs of gas transmission to the Newman operations (at GGP’s proposed Access Arrangement tariffs and assuming a 50% load factor for their operations) are likely to be in the order of \$15 million – or less than 2% of the export revenues from the Newman operations;
- A number of iron ore mines within reasonable proximity to the GGP have elected to obtain their electricity requirements from diesel fired generation, or for historical reasons are supplied by high voltage transmission lines from coastal power stations;
- Even if the Code could increase access to the GGP, it would, in Ventnor’s view, have no impact on competition in the international iron ore market”.

– **Market for Nickel**

- “Western Australia accounts for 18% of world nickel production, with production increasing from 108,000 tonnes in 1996 when the GGP was commissioned to 182,000 tonnes in 2001;
- WMC accounts for 57% of Western Australian nickel production and approximately 9% of world nickel production. WMC claims to be at the bottom of the world cost curve. Nickel costs have fallen by 25% over the last five years;
- WMC is the fifth largest producer of refined nickel in the world;
- International market prices for nickel experience significant volatility, indicating that vigorous competition exists in this market;
- The value of nickel exports from Western Australia in 2001 was \$2.07 billion but is forecast by ABARE to reach \$3.6 billion in 2003/04;
- Ventnor has calculated approximate GGP revenues from nickel producers (WMC, Anaconda and Cawse) using prices quoted in the GGP Access Arrangement, and assuming 70% load factor. These amount to approximately \$50 million per annum, or approximately 2.5% of total 2001 revenues from Western Australian nickel exports;
- By way of comparison, average world nickel prices dropped by more than 30% in US\$ terms between 2000 and 2001;
- On the basis of the above it is clear that the world nickel market is already highly competitive and Ventnor does not believe that increased

access to the GGP (if such were possible) would result in any increased competition within the international nickel market”.

– ***Market for Gold***

- “The value of gold production in Western Australia in 2001 was \$3,228 million;
- Western Australian gold production in 2001 accounted for 8% of world gold production. Almost 90% of this production was exported;
- Western Australian production has declined from a peak of 238 tonnes in 1997 to 192 tonnes in 2001;
- The gold industry has undergone substantial rationalisation, both in terms of ownership and the consolidation of treatment operations in recent years;
- The international gold price has experienced significant volatility in recent months increasing at one stage to a level of more than 40% above average US\$ prices for 2001;
- Gold price volatility relates to perceptions as much as the physical supply and demand of gold;
- Ventnor has estimated GGP transmission revenues from gold producers on the basis of GGP’s published Access Arrangement tariffs. These are approximately \$20 million pa and represent less than 1% of the value of Western Australian gold production in 2001;
- On the basis of the above Ventnor does not believe that any increased access to the GGP would result in any increased competition within the international gold market”.

– ***Prospective Markets for Large Scale Chemical Processors***

Anaconda Nickel and others carried out some conceptual feasibility work in 1999 and 2000 on the establishment of a large scale processing complex in the North Eastern Goldfields. Components included:

- large scale expansion of nickel production;
- magnesium production;
- phosphate fertilisers;
- rare earths processing;
- ammonia production;
- expanded sulphuric acid production.

Capital investment in these industries was expected to be in the order of \$6 billion. A total of 302 TJ/d of gas was required for process purposes, power generation and for nearby third party customers. Development of the complex called for large scale infrastructure, including:

- a gas pipeline linking the DBNGP with the North Eastern Goldfields;
- upgrading and extension of rail services;
- a major water development in the Officer Basin and connecting pipeline;

- port upgrades or the establishment of a new port at Oakajee.

Substantial government investment was required for this regional infrastructure, as well as major royalty concessions from the State Government, and matching concessions from the Federal Government.

According to Ventnor, the ingredients which were regarded as essential to the realisation of this concept included:

- processing on a large scale;
- massive private capital expenditure;
- provision of infrastructure support services such as gas, power, water and transport on a large scale;
- on-site manufacture of reagents to avoid costly transport;
- significant process linkages between plants with reagents such as acid and ammonia being produced centrally and utilised in a number of process operations;
- capture of a significant proportion of the world market for particular commodities;
- substantial government investment in infrastructure;
- substantial government subsidies through royalty and other concessions.

Ventnor expresses the view that:

“translating such a vision into reality would require all these elements being coordinated to come together essentially at the same time. Unfortunately the scale of what was proposed has so far proven to be beyond the reach of Anaconda, and there has been no indication that the substantial government support required would be forthcoming”

Anaconda's recent public statements have confirmed that further work on the Mount Margaret and GEMM pipeline projects have been deferred. The Mt Weld rare earth assets have been sold, and other Mt Weld activities have been deferred. Anaconda is also seeking to divest its interest in the Officer Basin water project. Exploration efforts are now being focused on tenements which can provide high-grade nickel feed to the Murrin Murrin plant, and tenement holding costs are being reduced through relinquishment, sale or farm-out.

Ventnor's report concludes:

"It should be apparent from the preceding discussion that the dream of a major chemical processing complex in the Northern and eastern Goldfields requires far more than low cost gas transmission to be viable. It is also clear that at the scale of development required for viability, gas transmission requirements exceed the developable capacity of the GGP by 2-3 times, and at this level by-pass options such as GEMM provide a serious - and probably lower cost - alternative."

ATTACHMENT 5 : GAS QUALITY SPECIFICATION

Gas Component	Units	EPIC DBNGP Broadest Cat A	EPIC DBNGP Broadest Cat B	EPIC DBNGP Broadest Cat C	EPIC DBNGP Cat A	EPIC DBNGP Cat B	EPIC DBNGP Cat C	GGT
Carbon Dioxide	%	3.6	4.0	4.0	3.6	4.0	4.0	3.6
Nitrogen	%							
Total Inerts	%	6.5	7.0	7.0	5.5	6.0	6.0	7.0
Hydroc. Dewpoint	Deg C	<0	<0	0	<0	<0	<0	0
@ Press mpa		2.5 - 8.72	2.5 - 8.72	2.5 - 8.72	2.5 - 8.72	2.5 - 8.72	2.5 - 8.72	10.0
Oxygen	%	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Sulphur	mg/m ³	10	10	10	10	10	10	10
Hydrogen Sulphide	mg/m ³	2	2	2	2	2	2	5
Mercaptain Sulphur	mg/m ³	10	10	10	10	10	10	10
Delivery Temperature	Deg C				50	50	50	
Water Vapour	mg/m ³	48	48	48	48	48	48	48
WOBBE Index (Min)	MJ/m ³	46.0	46.0	46.0	47.3	47.3	47.3	46
WOBBE Index (Max)	MJ/m ³	51.5	51.5	51.5	51	51	51	51.5
Heating Value (Min)	MJ/m ³	35.1	35.1	35.1	37.3	37.3	37.3	35.5
Heating Value (Max)	MJ/m ³	42.3	42.3	42.3	42.3	42.3	42.3	42.5
Minimum LPGs	t/TJ	1.45⁽¹⁾	na	na	1.45	na	na	
Radioactive Comp.	Becq/m ³	600	600	600	600	600	600	600

Note (1) Until 1 July 2005

ATTACHMENT 6 : OVERVIEW OF ECONOMIC DEVELOPMENT TARIFF (EDT)

(A GGP development initiative in 1999)

Background

The current owners of the GGP invested with the clear intention of further growing transportation demand. While it is a legitimate business imperative to maintain the baseline economic returns upon which the current owners based their investment decisions, it is also apparent that a proactive initiative is required to overcome the longstanding reluctance of Goldfields developers to commit to additional capacity usage. Failure to receive substantive commitment by potential Users makes investment in additional capacity highly speculative and thus unacceptable to shareholders.^{ix}

Hence, in September 1999, GGT, the manager of the GGP, announced the EDT Programme and sought initial expressions of interest. The EDT Programme was intended to further promote third party use of the GGP by offering tariffs lower than the existing scheduled (and already discounted) tariffs, already set to further reduce from 1 January 2000. The EDT initial "open season" period closed on 31 October 1999. The next phase of the Programme was to develop a specific tariff proposal for each customer to be offered on a consistent and non-discriminatory basis.

The EDT was offered to new resource development projects, which could have been 'greenfields' in nature, expansions of existing operations, or fuel conversions. In order for a project to pre-qualify, the anticipated project commissioning date was to be no later than December 2003. This cutoff date was necessitated in order that the appropriate investment in capacity expansion could be justified and practically scheduled.

Transportation contracts offered under the EDT regime were to be Negotiated Services in the context of the GGPA (i.e. not Reference Services). Both the terms and conditions and tariffs for EDT services were to be established through negotiations between the potential third party pipeline User and GGT, so that each potential User would receive a service tailored and optimised to the individual needs of the User.

^{ix} The fact that the proposed GEMM pipeline is justified from Geraldton, rather than as an extension of the existing Mid-West Pipeline, appears to be a direct result of the failure on the part of downstream Users to make the commitments necessary to justify the capacity investment (in this case, in the Mid-West Pipeline) required on the basis of their own demand projections.

Proposed Economic Development Tariff: Principles and Characteristics

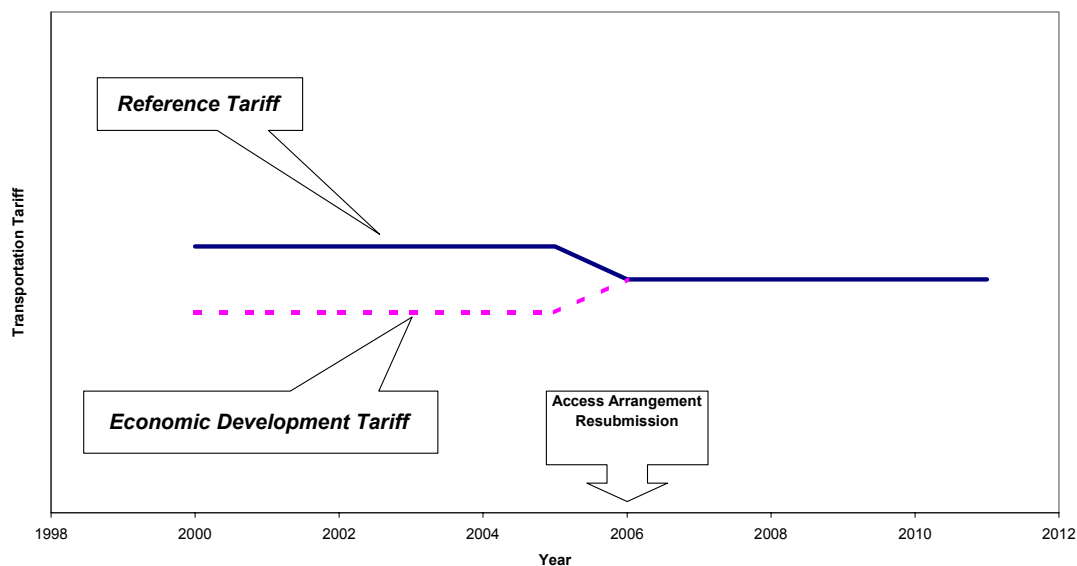
Relationship to Reference Tariff

It was proposed that the EDT would terminate at the earlier of the first scheduled revision of the GGPAA or 1 January 2006, regardless of when a User were to take up a service under the EDT.

It was envisaged that transportation contracts under the EDT would revert to the Reference (or Benchmark) Service tariff at the commencement of the second Access Arrangement period. To accommodate this, it was envisaged that load initially contracted under the EDT would be not be considered for the purposes of determining Reference Service Tariffs for the first Access Arrangement, but would be considered for Reference Service tariff determination for periods following the expiry of the EDT.

Figure 1 provides a simple graphical representation of the timing relationship between the Reference Service tariff and the EDT.

Figure 1: PRINCIPLES of GGT'S ECONOMIC DEVELOPMENT TARIFF PROGRAMME



Basis of Tariff Determination

It was proposed that the Economic Development Tariff would be based on marginal costing. The EDT would be determined on the incremental cost of providing additional pipeline capacity required to accommodate EDT Users. Additional pipeline capacity would be realised through the installation of further pipeline compression.

It was GGT's view that, whilst it was not compelled to offer marginally priced services, the planned tariff convergence with existing customers was equitable and that the approach taken represented both a prudent commercial strategy, as well as compliance with the spirit and the intent of both the State Agreement and the Code.

Proposed EDT Key Terms and Conditions

- 1) The EDT would be available only to direct proponents of new projects. The EDT would not be directly available to gas producers, traders or retailers as it was intended to promote realisable regional development and not facilitate the commercial advantage of intermediaries.
- 2) Application(s) for transportation under the EDT closed on 31 October 1999.
- 3) To qualify for the EDT, projects had to require gas transportation services by 31 December 2003, i.e. they had a four year development window.
- 4) If a project proponent were to commit to a transportation contract under the EDT but the project were not to proceed for reasonably specified reasons, the project proponent would be able to obtain release from the contract.
- 5) The EDT would terminate at the first revision of the GGPA, regardless of when a User were to take up a service under the EDT.
- 6) If a project proponent were to commit to a transportation contract under the EDT, that transport contract would be required to have a duration of at least five years after the termination of the EDT, i.e. the transport contract must endure for at least five years at the revised future Reference (or Benchmark) Service tariff.
- 7) Allocation of capacity transportation contracts which received the EDT would be on a first come, first served basis determined by application date following the close of the EDT offer and after total incremental pipeline capacity requirements had been established.
- 8) GGT reserved the right to refuse applications for transportation under the EDT where it was not technically and/or economically viable to provide additional pipeline capacity. Any such refusal would have been strictly on the basis of capacity allocation as described immediately above.
- 9) Specific terms and conditions for transportation under the EDT would not be 'standardised', but rather were intended to be negotiated on a flexible basis to accommodate the specific needs of individual Users.
- 10) The EDT would be a two part tariff, comprising a Reservation Charge and a Throughput Charge. The Throughput Charge component of the EDT would be proportionately larger than the Throughput Charge component proposed in the already prevailing GGP tariff structure, consistent with the incremental capacity being facilitated by additional investment in fixed pipeline compression, and hence representing firm commitments. As previously discussed however, the terms of the EDT for each user were negotiable.

Conclusion

The services offered under the EDT were substantially different from the Service from which benchmark tariffs have been and will be derived under either of the two regulatory regimes to which the GGP is currently subject. In offering an EDT, GGT was actively promoting the use of the GGP by third parties by offering a discount permissible under both the State Agreement Act and the Code.



**GOLDFIELDS GAS PIPELINE
REVOCATION APPLICATION**

APPENDIX 1: LOCATION MAPS

**Submitted to the
National Competition Council**

March 2003

GOLDFIELDS GAS PIPELINE SYSTEM

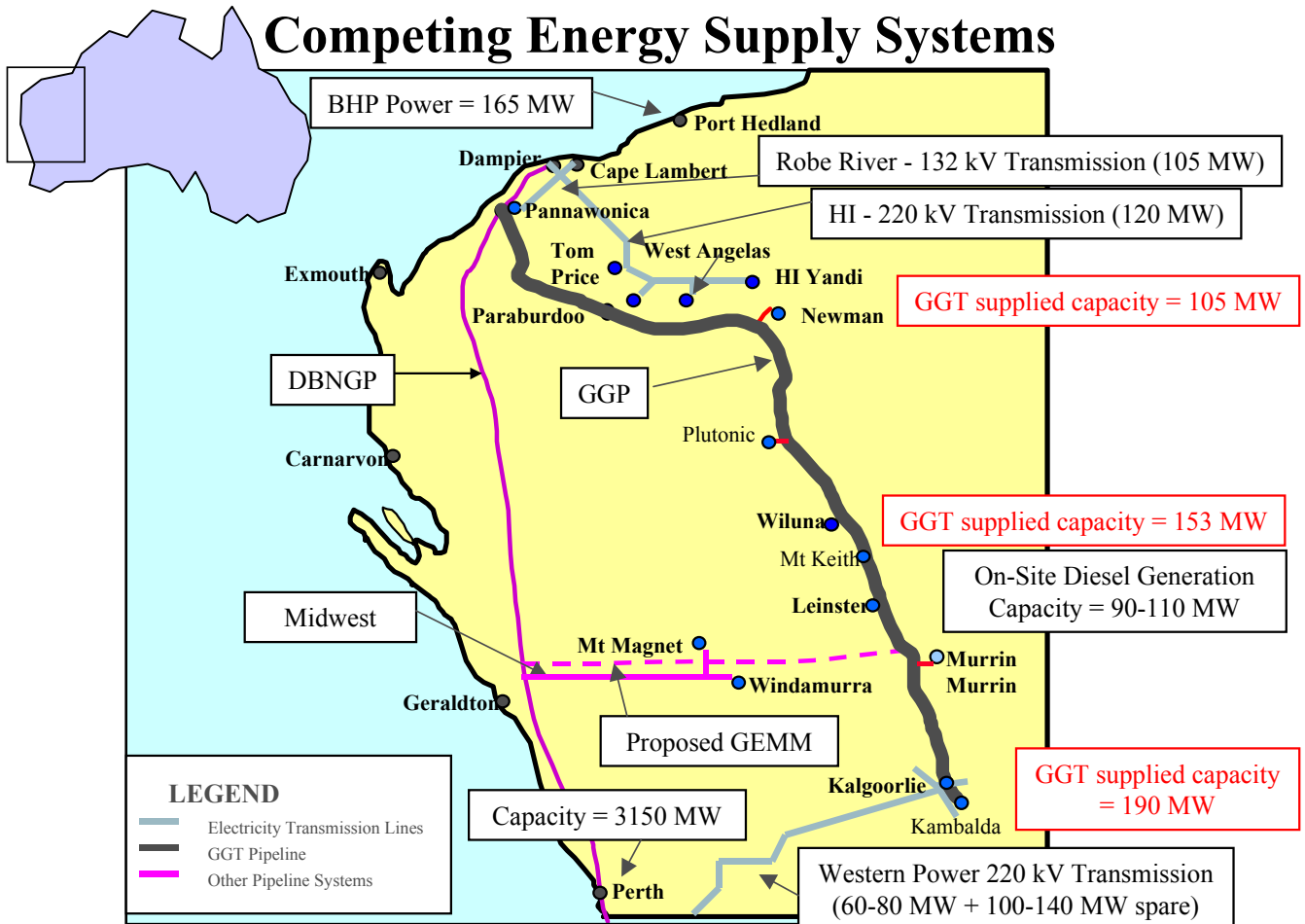


GOLDFIELDS GAS PIPELINE: LOCATION & DISTRIBUTION OF CUSTOMERS

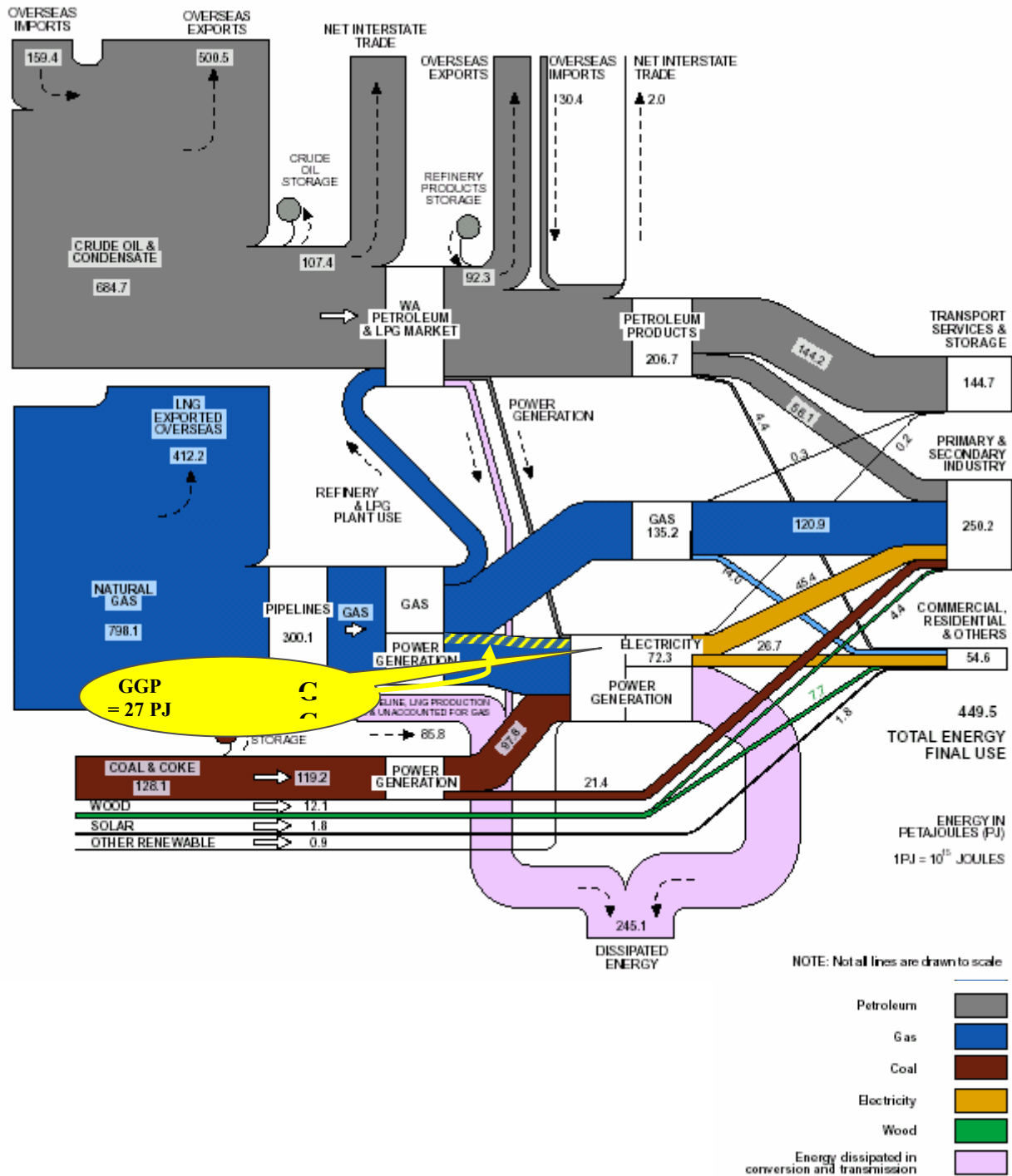


ENERGY TRANSMISSION INFRASTRUCTURE IN WESTERN AUSTRALIA

Competing Energy Supply Systems

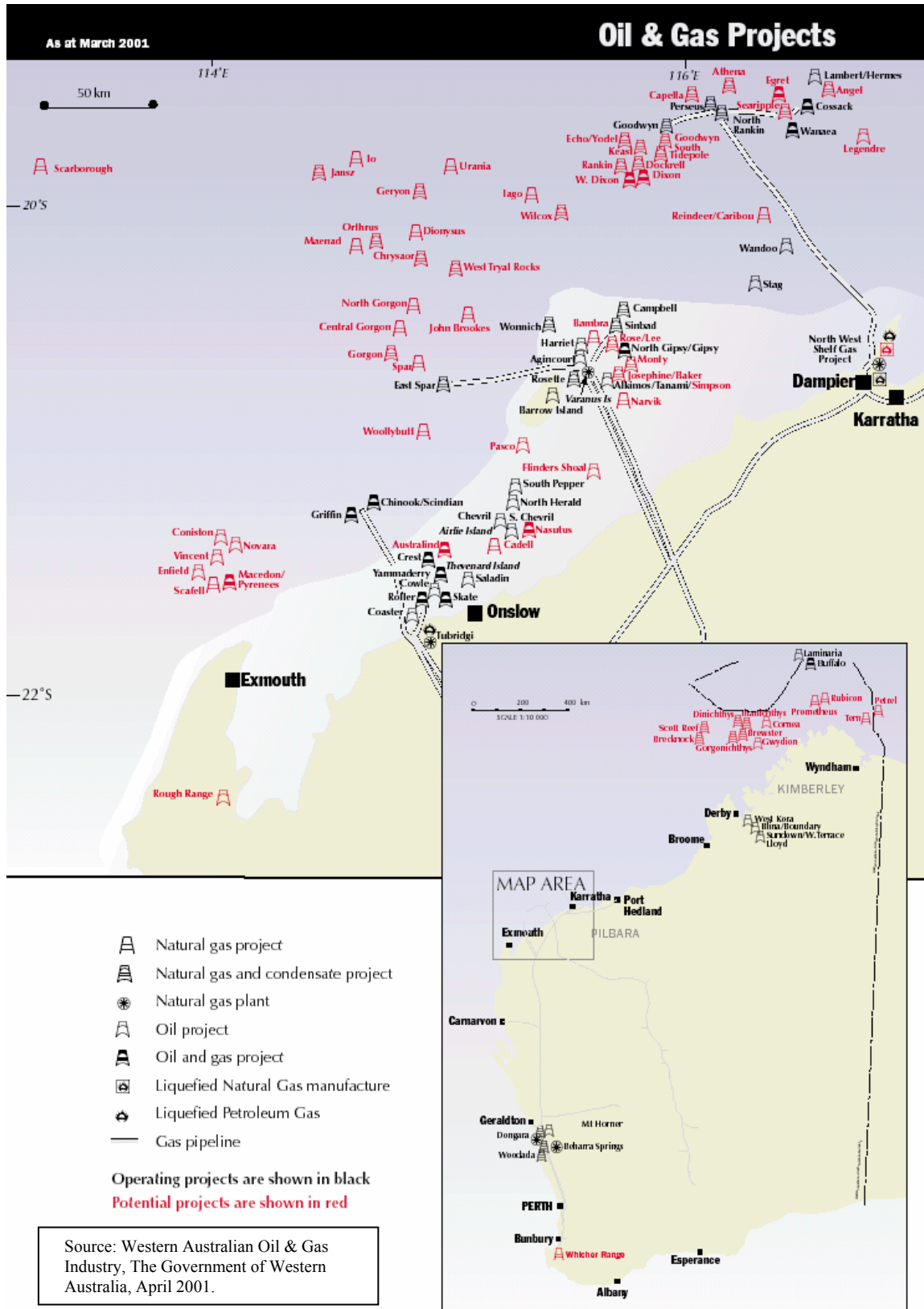


ENERGY SUPPLY AND DEMAND IN WESTERN AUSTRALIA



Source: WA Office of Energy, "Energy Western Australia 2001"

GOLDFIELDS GAS PIPELINE : UPSTREAM (SUPPLY) MARKET



AREAS SERVICED BY WESTERN POWER



Source: Western Power: Annual Report and Environmental Review 2001

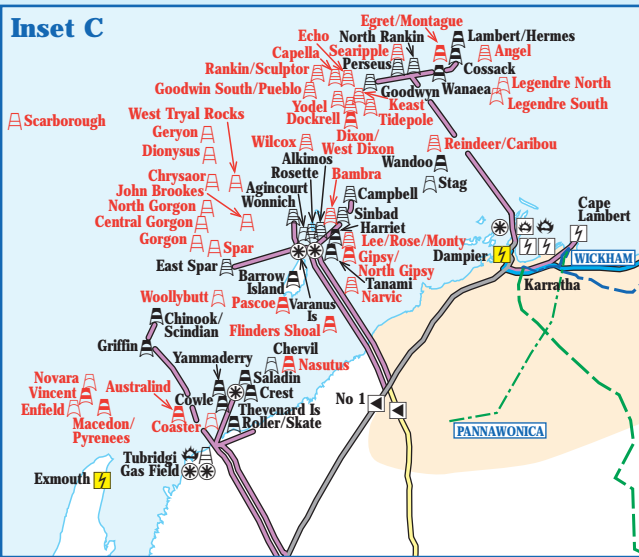


WESTERN AUSTRALIAN ENERGY RESOURCES AND INFRASTRUCTURE

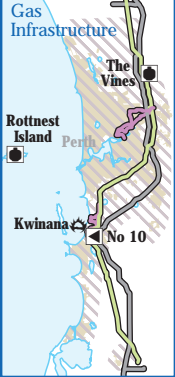
MAY 2000



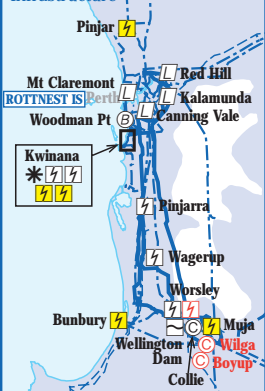
Inset C



Inset B



Inset A



Undeveloped resources/committed infrastructure developments are shown in red. Operational projects/infrastructure are shown in other colours.

ELECTRICITY GENERATION STATIONS

Non-renewable Energy

- Private >10 MW
- Western Power Corporation

Renewable Energy

- Bagasse
- Biogas
- Hydro
- Landfill Gas
- Photovoltaic
- Wind
- Towns supplied by Private Electricity Supply Authorities

ELECTRICITY TRANSMISSION LINES

Western Power Lines		Private Lines	
330kV	—	—	—
220kV	—	—	—
132kV	—	—	—
66kV	—	—	—

WESTERN POWER'S ELECTRICITY DISTRIBUTION SYSTEMS

- South West System
- Pilbara System
- Esperance System

ENERGY RESOURCES AND INFRASTRUCTURE

- Coal Deposit
- Coal Mine
- Liquefied Natural Gas Manufacture
- Liquefied Petroleum Gas Manufacture
- Natural Gas
- Natural Gas/Oil
- Natural Gas/Condensate
- Natural Gas Plant
- Natural Gas Storage
- Oil
- Oil Refinery
- Petrochemical/Chemical
- Uranium
- Sedimentary Basin

GAS

- AlintaGas Natural Gas High Pressure System
- AlintaGas Natural Gas Low/Medium Pressure System
- Liquefied Petroleum Gas Distribution System
- Gas Pipeline Compressor Station

NATURAL GAS TRANSMISSION PIPELINE

- Dampier to Bunbury Natural Gas Pipeline
- Goldfields Gas Pipeline
- Mid West Pipeline
- Parmelia Pipeline
- Pilbara Energy Pipeline
- Lateral Pipelines

Produced by the Department of Land Administration, 1 Midland Square, Midland, Western Australia, 6056, for the: Office of Energy, Level 9, Governor Stirling Tower, 197 St Georges Terrace, Perth, Western Australia, 6000. Phone: 61+8+9420 5600 Facsimile: 61+8+9420 5700 www.energy.wa.gov.au

DOLA
Department of Land Administration

0 200 400 600 km
Scale 1:10000000



VENTNOR CONSULTING GROUP

REPORT FOR
GOLDFIELDS GAS TRANSMISSION PTY LTD

GOLDFIELDS GAS PIPELINE
RELEVANT DOWNSTREAM
MARKETS

MARCH 2003

PO BOX 132 NORTH FREMANTLE 6159 WESTERN AUSTRALIA
Telephone (+61 8) 9319 8677 Mobile 0419 923 749
e-mail shohnen@bigpond.net.au
website www.ventnorconsulting.com.au



VENTNOR CONSULTING GROUP

GOLDFIELDS GAS PIPELINE

RELEVANT DOWNSTREAM MARKETS

CONTENTS

	Page
1.0 INTRODUCTION.....	1
2.0 OWNERSHIP HISTORY	2
3.0 THE GOLDFIELDS GAS PIPELINE	3
4.0 EXISTING SHIPPERS	6
5.0 DOWNSTREAM MARKETS	20
6.0 OPPORTUNITIES FOR LARGE SCALE PROCESSING.....	51



VENTNOR CONSULTING GROUP

Disclaimer

This report has been prepared by Ventnor Consulting Group for Goldfields Gas Transmission Pty Ltd.

It has been based on material in the public domain and Ventnor's own knowledge of the Western Australian resources and energy sector. Sources have included government publications, company reports and material available on government and company websites. All reasonable care has been taken to ensure that the information presented is accurate; however, it has not been possible to independently verify data which has been drawn from government and company sources.

The opinions expressed in the report are those of Ventnor Consulting Group. While reasonable care has been taken to ensure the accuracy of the information provided, no warranty, whether express or implied, is given in respect of the information presented or any conclusions which may be drawn from that information. No liability is accepted for the consequences of any action which may be based wholly or in part on the information and interpretations presented in this report.



VENTNOR CONSULTING GROUP

ABBREVIATIONS

Code	National Third Party Access Code for National Gas Pipeline Systems
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DCQ	Daily Contract Quantity
Fe	Iron
FY	Fiscal Year
GGP	Goldfields Gas Pipeline
GGT	Goldfields Gas Transmission Pty Ltd
GJ	Gigajoule
GP	Goldfields Power
GWh	Gigawatt hour
KCGM	Kalgoorlie Consolidated Gold Mines Pty Ltd
kJ/kWh	Kilojoules per kilowatt hour
km	Kilometres
kV	Kilovolt
kW	Kilowatt
LPG	Liquefied Petroleum Gas
LNG	Liquefied Natural Gas
MDQ	Maximum Daily Quantity
Mt/a	Million tonnes per annum
mm	millimetres
MW	Megawatt
Ni	Nickel
NWSG	North West Shelf Gas
NWSJVP	North West Shelf Joint Venture Participants
oz	ounces
PJ	Petajoules
SCE	Southern Cross Energy
State Agreement	Goldfields Gas Pipeline Agreement Act 1994
SWIS	South West Interconnected System
t/a	tonnes per annum
TJ/d	Terajoules per day
Ventnor	Ventnor Consulting Group



1.0 INTRODUCTION

The Goldfields Gas Pipeline (GGP) was commissioned in 1996 and receives gas from the Harriet and East Spar gas-fields at Yarraloola in the Pilbara Region of Western Australia. The GGP extends 1380km to Kalgoorlie and delivers gas to a number of customers in the Pilbara, Northern and Eastern Goldfields (see Attachment 1 - Office of Energy Map of Energy Resources and Infrastructure).

The GGP was constructed pursuant to an Agreement with the State Government, the Goldfields Gas Pipeline Agreement Act 1994 (the State Agreement). The State Agreement incorporated arrangements for third parties to gain access to the pipeline, and for the determination of Indicative Tariffs.

With the passage in 1999 of the Gas Pipelines Access (Western Australia) Act 1999, which incorporated the National Third Party Access Code for Natural Gas Pipeline Systems (the Code), the GGP was deemed to be a Covered Pipeline as defined in the Code. The third party access arrangement approved under the State Agreement was taken to be an approved Access Arrangement under the Code until 1 January 2000. The GGP continues to be subject to the overlapping requirements of the State Agreement and the Code.

In November 1999, Goldfields Gas Transmission Pty Ltd (GGT) the manager of the GGP on behalf of the joint venture owners, submitted a draft Access Arrangement to the Western Australian Independent Gas Pipeline Access Regulator (the Regulator). The Regulator published his Draft Decision in April 2001. The Draft Decision is currently the subject of litigation between the joint venturers, the Regulator and the State.

The owners of the GGP have requested Ventnor Consulting Group (Ventnor) to prepare an independent report on the relevant downstream markets being served by the GGP and whether, or the extent to which, competition in any of these markets would be promoted by coverage of the GGP. In preparing this report Ventnor has assumed that the specific service being provided by the GGP is that of transmission of gas from the inlet point at Yarraloola to Kalgoorlie or any off-take points upstream of Kalgoorlie.



2.0 OWNERSHIP HISTORY

The GGP was originally constructed by a consortium of mining and processing companies – WMC (62.664%); Normandy (25.493%); and BHP (11.843%) – who were the original parties to the State Agreement. The purpose was to provide for the electricity requirements of a number of mining and processing projects - owned and operated by the individual joint venturers – which were, in the main, established prior to the commissioning date of the GGP in 1996.

The WMC and Normandy interests were purchased in December 1998 and March 1999 by Southern Cross Pipelines Australia Pty Limited and Southern Cross Pipelines (NPL) Australia Pty Ltd respectively. Both of these companies are owned in the following proportions by:

- CMS Energy 45%
- Australian Pipelines Trust 45%
- TransAlta 10%

In March 2003 it was reported that agreement had been reached for the Australia Pipelines Trust to purchase the TransAlta interest.

The BHP interest was purchased separately by Duke Energy WA Power Pty Ltd in January 1999.

Current ownership of the GGP is therefore:

- Southern Cross Pipelines Australia Pty Limited 62.664%
- Southern Cross Pipelines (NPL) Australia Pty Ltd 25.493%
- Duke Energy WA Power Pty Ltd 11.843%

As indicated previously a management company, Goldfields Gas Transmission Pty Ltd, has responsibility for managing the project on behalf of the owners and has contracted Agility (an AGL subsidiary) to operate and maintain the pipeline, and CMS Energy to provide commercial and regulatory support services. GGT is the designated Service Provider under the Code.



3.0 THE GOLDFIELDS GAS PIPELINE

The GGP receives gas from the Apache operated offshore Harriet and East Spar gas-fields at Yarraloola, which is close to Compressor Station 1 on the Dampier to Bunbury Natural Gas Pipeline (DBNGP). Gas is delivered to a number of off-take points along the 1380 km pipeline length to Kalgoorlie (see Figure 1). Laterals owned and operated by others – with one exception – connect the GGP to various mining and processing operations. These are listed in Table 1 below.

Table 1

Goldfields Gas Pipeline Laterals

Operation	Pipeline Licence	Distance along GGP (km)	Length (km)	Diam. (mm)	Ownership
BHP - Newman	WA – PL:24	520	50	219	GGP Joint Venture
Plutonic	WA – PL:35	702	19.2	114	Plutonic Operations Limited (Barrick)
Wiluna	WA – PL:33	863	8	89	Wiluna Gold Pty Ltd (Normandy)
Jundee	WA – PL:34	863	45	114	Great Central Mines Ltd (Normandy)
Mt Keith	WA – PL:25	946	8.1	219	Southern Cross Pipelines Australia Pty Ltd
Leinster	WA – PL:26	1012	5.2	219	Southern Cross Pipelines Australia Pty Ltd
Murrin Murrin	WA – PL:36	1142	85	219	Origin Energy Pty Ltd
Leonora Power Station	WA – PL:48	1142.8	16.5	89	Statewest Power Pty Ltd
Cawse	WA – PL:37	1230	35	168	OM Group
Goldfields Power	WA – PL:28	1355.8	8.2	219	Southern Cross Pipelines (NPL) Australia Pty Ltd
WMC - Kambalda	WA – PL:27	1378	44.3	219	Southern Cross Pipelines Australia Pty Ltd

The exception is the 50 km lateral connecting the GGP with BHP Iron Ore’s operations at Newman. This lateral is owned and operated by the joint venture and subject to the same pipeline licence as the GGP (WA: PL24). It is, therefore, part of the Covered Pipeline under the Code.



The GGP has a diameter of 406 mm for the first 520 km to the Newman off-take point. For the remaining 858 km to Kalgoorlie, the pipeline diameter reduces to 356 mm.

Its current capacity with three compressor stations is 100 TJ/d, but with a further six compressor stations this can be increased to 164 TJ/d. While the DNBNGP and GGP systems cross, the DNBNGP does not currently supply gas into the GGP. Ventnor understands that there is an interconnection between the two pipelines for use in supply emergencies and that GGT is prepared to install a permanent interconnection for a material gas quantity.

Clause 17 of the State Agreement expressly provides for third party access to the DNBNGP in order to enable gas from NWSG and other sources linked to the DNBNGP to supply GGP shippers. This provision has, however, become redundant since the implementation of a third party access regime for the DNBNGP.

The GGT Access Arrangement projects transmission capacity commitments increasing from 98.2 TJ/d (2000) to 102.2 TJ/d (2002) and then dropping to 95.9 TJ/d by 1994. Throughput is projected to increase from 71 TJ/d to 74 TJ/d and then drop to 69 TJ/d over the same period, reflecting an aggregate load factor for the GGP of 0.72⁽¹⁾.

In a public submission to the Acting Gas Access Regulator in December 2002, GGT provided a revised outlook for capacity commitments and throughput. This is reproduced in Table 2 below:

Table 2

GGT's 2002 Outlooks for its Load Forecasts

June 30 Fiscal Year	2002 Outlook	
	MDQ	Throughput
2000	108.4(a)	77.4(a)
2001	110.3(a)	83.5(a)
2002	109.3(a)	81.5(a)
2003	108.4	81.5
2004	100.1	78.5
2005	97.9	80.3
2006	98.2	80.6
2007	98.2	80.5

⁽¹⁾ 12 months to September 1999 – Access Arrangement Information



VENTNOR CONSULTING GROUP

Figure 1

GOLDFIELDS GAS PIPELINE SYSTEM





4.0 EXISTING SHIPPERS

4.1 Initial Customers

Under the State Agreement, GGP shippers fall into two categories:

- Initial Customers which made commitments to pipeline capacity (Initial Committed Capacity) prior to the construction of the GGP; and
- third parties other than Initial Customers.

The Initial Customers for the GGP were, without exception the original joint venture owners, whose operations are described below.

4.1.1 BHP Iron Ore – Newman Operations

Mining of the massive Mt Whaleback orebody near Newman commenced in 1969 on completion of the 426 km Newman to Port Hedland railway. Since that time a number of satellite orebodies have been developed in the vicinity of Newman. Together these mines produce approximately 30 Mt/a of blended iron ore product⁽²⁾.

BHP operates another major iron ore mine at Yandi, some 90 km north-west of Newman, which commenced operations in 1992. Yandi is currently producing approximately 31 Mt/a of pisolitic fine ore. A further 7 Mt/a of iron ore is produced from mines at Yarrie, approximately 200 km to the east of Port Hedland and connected by separate railway.

From the commencement of operations in 1969, BHP Iron Ore (or the former Mt Newman JV) operated its own diesel fired generation facilities to provide the power requirements of its mining, crushing and ore handling operations in the vicinity of Newman. The company has also continued to act as the electricity supply authority for the township of Newman, with a population of approximately 3,000. Newman was originally built as a company town, but responsibility was transferred to the East Pilbara Shire in 1981.

BHP joined the GGP project in 1994 when it saw the opportunity to replace its aging fleet of diesel generators (66 MW capacity⁽³⁾) at Newman with modern gas turbine equipment. A new station with a nominal capacity of 105 MW – comprising 3 x 35 MW gas turbines – was constructed and commissioned in

⁽²⁾ Dept. of Mineral & Petroleum Resources – Western Australian Iron Ore Industry 2002

⁽³⁾ Office of Energy – Energy Western Australia (June 1996)



1996. This is a stand-alone station and is not interconnected with other centres in the Pilbara region. Ventnor understands that BHP Iron Ore's peak power requirement from this station is in the order of 30 MW.

At the same time BHP Iron Ore constructed a new gas fired power station at Port Hedland with a nominal capacity of 175 MW, to provide the power requirements of its port operations and the Boodarie HBI processing plant. This facility is linked to the Pilbara coastal transmission grid operated by Western Power, and supplies some power to Western Power and third party customers.

BHP Iron Ore's Yandi operations continue to obtain their power requirements from on-site diesels and have, to date, been unable to justify interconnection with the Newman gas fired station.

Interestingly, Hamersley Iron the other major iron producer in the Pilbara has historically supplied its inland mining operations at Tom Price and Paraburdoo by 220 KV transmission line from its central gas fired power station at Dampier. Notwithstanding the proximity of Paraburdoo to the GGP (approximately 20 km), Hamersley Iron has not moved to install gas fired generation there.

In early 1999 Duke Energy purchased BHP Iron Ore's generation assets at both Newman and Port Hedland, and at the same time purchased BHP Iron Ore's interest in the GGP. BHP is understood to have a contract for 7 TJ/d⁽⁴⁾ with the East Spar Joint Venture for the supply of gas to Duke's Newman facilities. Ventnor understands that with the exception of Newman township reticulation - which BHP Iron Ore itself provides - Duke does not supply power to other significant third party operations in the area.

4.1.2 WMC Limited

WMC has a number of significant nickel mining and processing operations in Western Australia, all except one of which are situated along the route of the GGP. The magnitude of these operations in energy terms can be gauged from the fact that WMC holds gas supply contracts with the East Spar Joint Venture amounting to 46 TJ/d⁽⁴⁾. Ventnor understands that the majority of this is consumed in the Northern and Eastern Goldfields operations with the balance consumed in WMC's Kwinana Nickel Refinery.

⁽⁴⁾ Office of Energy – Energy Western Australia 2003



The Office of Energy⁽⁵⁾ shows WMC holding two gas supply contracts, of 37 TJ/d and 9 TJ/d respectively, suggesting consumption of 37 TJ/d within the Northern and Eastern Goldfields operations. This is borne out by the fact that WMC holds a contract for DBNGP transmission capacity of 10.2 TJ/d⁽⁶⁾.

It is important to realise that in contracting for gas transmission capacity it is necessary to reserve sufficient capacity for peak gas requirements. This is in contrast to gas supply contracts which normally provide for some variability in deliveries. Apache contracts, for example, normally provide for a daily contract quantity (DCQ), with the supplier liable to deliver a maximum daily quantity (MDQ) 10-15% higher than DCQ. Transmission contracts, for this reason, are invariably for a greater capacity than the corresponding gas supply volume.

Mt Keith Operations

Mt Keith is the most northerly, and the most recent of WMC's Western Australian nickel operations. Its off-take is located approximately 946 km downstream from the GGP inlet point. Mt Keith is a low grade disseminated sulphide orebody, mined by open cut methods. Project go-ahead was announced in February 1993 - well ahead of WMC's commitment to the GGP - and first ore was treated in September 1994.

After mining the ore is crushed, ground and concentrated in a flotation plant to produce a concentrate with approximately 20% contained nickel. From a capacity of 28,000 tonnes of nickel in concentrate, the operation has expanded to 48,000 tonnes in 2001. Ventnor understands that approximately 70% of the concentrate is transported to WMC's Kalgoorlie nickel smelter for further processing, with the balance being sold to Finnish processor Outokumpu.

Power for the facilities was originally supplied from a WMC owned and operated diesel generating station. On completion of the GGP, a gas turbine unit of 38 MW capacity was installed by WMC, with the diesel units and associated diesel storage retained for back-up. In early 1999, shortly after WMC's interest in the GGP was sold, its power interests were also sold to Southern Cross Energy (SCE), a partnership between TransAlta of Canada (85%) and AGL (15%).

The Mt Keith open-cut mine is primarily operated with conventional diesel equipment. The principal uses for electricity are in crushing, grinding,

⁽⁵⁾ Office of Energy – Energy Western Australia 2003

⁽⁶⁾ Office of Energy - Energy Western Australia (July 1997)



flotation, pumping, and handling operations. Ventnor is not aware of any gas usage at Mt Keith for other than electricity generation.

WMC's focus at present is on increased nickel recovery and concentrate quality. WMC presentations⁽⁷⁾ quote power costs as comprising 17% of total costs for its Mt Keith operations. The principal components of delivered power costs for an operation such as Mt Keith – regardless of whether services and facilities are directly owned/supplied or provided under contract – are:

- gas supply (East Spar JV);
- gas transportation (GGP);
- gas lateral (Southern Cross Pipelines Australia Pty Ltd);
- power station capital costs (SCE);
- power station operating and maintenance costs (SCE);
- cost of back-up facilities (SCE);
- costs of electricity distribution on site (WMC).

WMC has plans to expand from current throughput of 11 Mt/a to 16 Mt/a; however WMC advised that⁽⁷⁾ current resources are sufficient for a 20 year life at 20 Mt/a.

Leinster

The Leinster off-take is located approximately 1012 km downstream from the GGP inlet point. These operations were originally based on the Agnew nickel mine discovered and developed by Selection Trust in the late 1970's. MIM was subsequently introduced as a partner but the underground operation was moth-balled in the 1980's at a time of low nickel prices. WMC purchased the assets in 1989 and initially focused on open cut opportunities in the vicinity. Production from the underground Perseverance mine did not commence until 1995. Production at the adjacent Harmony mine commenced in 2000.

In 2002 the Leinster operations mined and processed a total of 2.6 Mt/a of high grade sulphide ore to produce 40,000 t/a of 12% nickel concentrate. This level of production has more than doubled over the past ten years.

From its inception, power was supplied to the Leinster operations by company owned and operated diesel generation units. On completion of the GGP pipeline in 1996, WMC installed a 38 MW gas turbine. As with Mt Keith the diesel facilities were retained as back-up. The Mt Keith and Leinster power

⁽⁷⁾ WMC website – www.wmc.com.au – Operations Briefings June 2002



stations have subsequently been interconnected by high voltage transmission line for added security. SCE purchased these generation assets in early 1999.

Ventnor understands that as with the Mt Keith operations, power is used primarily in crushing, grinding, flotation and ore handling. WMC presentations⁽⁸⁾ cite energy as comprising 10% of direct costs. It is not clear whether this includes diesel used by contractors' mining equipment.

Until recently WMC owned the Agnew gold operation, located near Leinster which were also supplied from the Leinster power station. However, this operation was sold to the South African Gold Fields group in September 2001. The operation consists of a number of underground and open pit mines, and associated processing plant. Ventnor understands that under the sale agreement, WMC continues to supply power to these operations.

Another gold mine in the vicinity, the Lawlers Mine partially converted from on-site diesel during 2001 and is now supplied by SCE for a portion of its requirements through the limited northern grid. Lawlers is located 23 km south-west of Leinster and was recently purchased by US company Barrick Gold. In 2002 it produced 113,000 oz of gold from a combination of open pit and underground operations.

Kalgoorlie Nickel Operations

WMC first discovered high grade nickel sulphide at Kambalda, 50 km south of Kalgoorlie in 1966. The first nickel concentrate was produced the following year and shipment to the newly completed Kwinana Nickel Refinery commenced in 1970. The Kalgoorlie Nickel Smelter commenced operation in 1972.

Since 1998 WMC has closed a number of nickel mines in the Kambalda area, and has divested the remainder to smaller more focused mining companies. WMC continues to process ore from those mines which remain in operation, under contract in its Kambalda Nickel Concentrator. Concentrate production dropped from 34,000 tonnes of nickel in concentrate in 1998 to 11,000 tonnes in 1999. It has since recovered to 23,000 tonnes in 2002. Concentrate from the Kambalda plant is processed in the Kalgoorlie Nickel Smelter, along with concentrate from Mt Keith, Leinster and other producers.

The Kalgoorlie Nickel Smelter upgrades the concentrate to a matte containing approximately 72% nickel metal. Since 1996 sulphuric acid, produced from

⁽⁸⁾ WMC website – www.wmc.com.au – Operations Briefings – June 2002



the scrubbing of sulphur dioxide emissions became a significant by-product of the smelting operations. Smelter capacity has increased over the years to the current level of approximately 100,000 tonnes/annum, although technical problems limited actual production in 2002 to 92,000 tonnes. WMC presentations⁽⁹⁾ cite energy costs as comprising 31% of total direct costs for the smelting operation, but give no breakdown of the nature or application of energy used in the operations.

The bulk of the power requirements for WMC's operations in the vicinity of Kalgoorlie and Kambalda were originally met from company owned diesel generators. In 1984 the State Energy Commission of Western Australia (SECWA) - now Western Power - completed a 220 kV transmission line from its Muja Power Station at Collie to Kalgoorlie. This project was enabled through direct financial support from WMC itself and linked the Eastern Goldfields for the first time with the South West Interconnected System (SWIS). Ventnor understands that WMC also provided some stand-by generation support in the Kalgoorlie area.

Power from the SWIS replaced the bulk of WMC's diesel generation from about 1984 until the completion of the GGP in 1996. At this time WMC commissioned new 38 MW gas turbine generators at Kalgoorlie and Kambalda respectively, both of which were linked to the SWIS. These turbines were sold to Southern Cross Energy – along with the Mt Keith and Leinster facilities – in early 1999.

The off-take point on the GGP for gas supply to the Kalgoorlie Nickel Smelter and Kambalda operations is located approximately 1378 km south of the inlet point. Southern Cross Pipelines Australia Pty Ltd now owns and operates the respective laterals supplying these two operations.

For many years WMC operated a number of gold mines – known as the St Ives Gold Operations – in the vicinity of Kambalda. The electricity requirements of these operations have been met from WMC's generating facilities, subsequently sold to SCE. In September 2001, WMC sold these operations (plus the Agnew Gold Mine near Leinster) to Gold Fields Limited of South Africa. Ventnor understands that under terms of the St Ives sales arrangements, SCE continues to supply electricity to these operations.

Ventnor does not have detailed information regarding WMC's gas usage in its Kalgoorlie and Kambalda operations, but understands that the bulk is utilised in the generation of electricity, with a relatively small proportion being used in

⁽⁹⁾ WMC website – www.wmc.com.au – Operations Briefings – June 2002



applications such as pre-heating and/or drying. Prior to the completion of the GGP, the latter would have been provided by liquid fuels.

The Kalgoorlie and Kambalda power stations, now owned and operated by SCE, have surplus generation capacity over and above WMC's requirements. Southern Cross Energy has endeavoured to sell this surplus to third parties connected to the SWIS. Ventnor understands that sales of approximately 20 MW are currently being made to the Water Corporation, Fremantle Hospital and the Karrinyup Shopping Centre. Despite a 13% energy advantage in supplying against the flow into the Perth metropolitan market, Ventnor believes that SCE is required to price on a marginal basis to be competitive with Western Power and the other two electricity retailers Alcoa and Worsley. Western Power, the State owned vertically integrated electricity utility, retains the dominant market position.

Kwinana Nickel Refinery

The Kwinana Nickel Refinery was commissioned in 1970 and processes matte and concentrate from WMC's other operations. From a level of 15,000 t/a of nickel metal (99.8% Ni), production has increased to a rate of 65,000 tonnes in 2002. The refinery produces a number of by-products, including ammonium sulphate, copper sulphide and cobalt/nickel sulphide.

While the Kwinana Nickel Refinery is not directly linked to the GGP, since the commissioning of WMC's gas fired power stations at Kalgoorlie and Kambalda in 1996, its electricity requirements have been supplied from these stations through the SWIS. Ventnor understands that the refinery requires in the order of 14 MW of electricity, in addition to the approximately 9 TJ/d of gas shipped down the DBNGP for process purposes. WMC presentations⁽¹⁰⁾ quote power and natural gas each comprising 12% of total direct refining costs.

4.1.3 Normandy Mining Limited

Jundee Operations

Normandy's Jundee Operations are located 45 km north-east of Wiluna and in 2001 sold 405,000 oz. of gold. The Jundee mine, which commenced production in 1995, was originally owned by Great Central Mines Ltd, which subsequently acquired and integrated the adjoining Ninary operations.

⁽¹⁰⁾ WMC Website – www.wmc.com.au – Operations Briefings – June 2002



Normandy acquired a strategic interest in Great Central Mines in 1997 and moved to full ownership in 2000. Normandy itself has, during 2002, been acquired by Newmont Mining Corporation, a major US gold mining company. Jundee and Nimary were originally supplied with electricity from remote diesel power stations of 10 MW and 4 MW capacity respectively. Once Normandy acquired its strategic interest in Great Central Mines in 1997, a gas lateral was constructed to Jundee to supply gas to a company owned power station of 13.2 MW capacity.

Ventnor understands that gas transmission services are supplied to this power station via the GGP under Normandy's "Initial Customer" capacity allocation.

Wiluna Mines

The Wiluna mine has operated intermittently for over 100 years. Asarco recommenced mining in 1987, changing its name to Wiluna Mines Ltd in 1994. It was purchased by Great Central Mines in 1997, at which time Normandy acquired its strategic interest in Great Central. The 10 MW diesel power station was converted to gas firing in 1997. Normandy assumed 100% ownership of Wiluna in 2000, with Newmont acquiring Normandy in 2002. Gold production is currently at a rate of approximately 90,000 oz/a.

Ventnor understands that gas transmission services continue to be supplied to this operation via the GGP under a standard third party gas contract, rather than being treated as part of Normandy's "Initial Customer" allocation.

Kalgoorlie Operations

Kalgoorlie Consolidated Gold Mines Pty Ltd (KCGM), which owns the Kalgoorlie Superpit, is an equal partnership between Normandy (now Newmont) and Homestake Gold (now Barrick). With the closure of the Mt Charlotte underground mine in December 2002 (also owned by KCGM), and the Kaltails tailings treatment operation (Normandy - 90%; GoldCorp - 10%), Normandy's one remaining mine in the Kalgoorlie area is the Superpit. This is Australia's largest goldmine and the open pit will ultimately extend to a pit 4 km long, 1.5 km wide and 650 metres deep.

Mine movement is currently at a rate of 85 Mt/a, including 12 Mt/a of ore. In the year to June 2001 a total of 875,000 oz of gold was produced from the Mt Charlotte and Superpit mines (ie. less than 1 oz of gold for every 100 tonnes mined). Production for 2002 was expected to be approximately 620,000 oz.



Normandy cite⁽¹¹⁾ a remaining mine life of 14 years, with the potential to increase this, possibly with underground operations.

Ore is treated at the Fimiston concentrator, which was specifically designed to process the Superpit sulphide ore. The concentrator underwent a major expansion in 1994-95 with the addition of grinding, flotation and carbon-in-leach capacity, and a separate circuit for free-milling Mt Charlotte ore.

Sulphide concentrates produced at Fimiston are roasted at KCGM's Gidgi roaster, 17 km north of Kalgoorlie. Two fluid bed roasters have a combined capacity of 380,000 tonnes of concentrate per annum.

Prior to the commissioning of the GGP, KCGM obtained its power requirements from Western Power via the 220 kV transmission line from Muja. Development of the GGP triggered the development of the Parkeston Power Station. This 114 MW station, comprising 3 x 38 MW gas turbines, is owned by Goldfields Power (GP), a 50:50 joint venture between TransAlta and Normandy. KCGM is understood to consume approximately 45 MW of power in its own operations⁽¹²⁾. The Office of Energy⁽¹³⁾ reports that Newmont, Great Central Mines and Wiluna Mines have gas contracts with the Apache led Harriet Joint Venture totalling 18.5 TJ/d.

GP has surplus generation capacity available for sale into the third party market; however, sales are currently restricted by tie-line constraints and other technical issues.

4.2 Third Party Shippers

Ventnor understands that transmission capacity commitments by third parties currently comprise approximately 20 TJ/d out of total capacity commitments of approximately 100 TJ/d⁽¹⁴⁾. The balance of more than 80 TJ/d comprise commitments by Initial Customers. Each of the third party operations is described below:

⁽¹¹⁾ Newmont Mining Corporation website – www.newmont.com

⁽¹²⁾ Grant Samuel expert report on AngloGold take-over offer for Normandy (Nov 2001)

⁽¹³⁾ Office of Energy – Energy Western Australia 2003

⁽¹⁴⁾ GGT Access Arrangement (Nov 1999)



4.2.1 *Plutonic Mine*

The Plutonic gold operations are located approximately 185 km south of the Newman off-take. Production takes place from both open-pit and underground sources. Mining commenced in 1990 and there have subsequently been several major plant upgrades. A total of 307,000 oz of gold was produced during 2002.

The operations were originally owned by Plutonic Resources and were acquired by Homestake Gold in 1998. Homestake merged with major US gold producer, Barrick Gold in December 2001.

Processing is carried out in two carbon-in-leach plants, with a combined capacity of 3 Mt/a. Mining reserves are quoted by Barrick as 2.5 million oz as at December 2002, or approximately eight years at current production rates. This is anticipated to increase with further exploration.

Power was originally supplied from company owned diesel operated generation sets. These were replaced in 1997 with the construction of a gas lateral of 19.2 km and a 20 MW gas fired power station. The Office of Energy reports⁽¹⁵⁾ that Plutonic has a gas contract with the Apache led East Spar Joint Venture for 3 TJ/d.

4.2.2 *Anaconda – Murrin Murrin Operations*

The Murrin Murrin nickel operations are located east of Leonora in the North Eastern Goldfields region. They are owned by a 60:40 joint venture between Anaconda Nickel Ltd and Glencore. Glencore also has a substantial shareholding in Anaconda. Murrin Murrin is the largest of three new lateritic projects (Murrin Murrin; Cawse; and Bulong) commenced in Western Australia in the late 1990's.

The Murrin Murrin operations are based on a large low grade lateritic orebody and the utilisation of relatively untested high pressure acid leach technology. The original design basis was for 4 Mt/a mill feed, and production of 45,000 t/a nickel and 3,000 t/a cobalt. Project construction commenced in May 1997, with mechanical completion achieved in December 1999.

The lateritic ore is treated with sulphuric acid at high temperature and pressure in purpose built autoclaves. Acid is produced on-site from the burning of elemental sulphur, which provides the heat source for the generation of a

⁽¹⁵⁾ Office of Energy – Energy Western Australia 2003



substantial proportion of the electricity requirements for the project. The processing circuit includes neutralisation and precipitation of a mixed metal sulphide, followed by leaching, solvent extraction and hydrogen steps to produce nickel and cobalt metal.

The Murrin Murrin operations have experienced serious commissioning difficulties, with nickel production in the fiscal year 2001/02 totalling only 28,652 tonnes – or approximately 64% of design output. Unfortunately the commissioning has coincided with a period of low nickel and cobalt prices.

As indicated above, the heat generated from sulphur burning is converted to steam and power in 2x28 MW steam boilers. In addition, Anaconda operates a 20 MW gas turbine at Murrin Murrin to provide the balance of its electricity needs.

As well as its use in the generation of power, natural gas is used within the plant for the manufacture of hydrogen. The hydrogen plant is owned and operated by BOC Gases Australia under a twenty year supply contract. Ventnor understands the plant produces approximately 22 tonnes/day of hydrogen, which is used in the production of nickel and cobalt.

Gas requirements of up to 13 TJ/d are provided under an arrangement with Origin Energy, which constructed an 85 km lateral from the GGP. The source of the gas is the Apache led Harriet Joint Venture. An Anaconda presentation⁽¹⁶⁾ cites natural gas as comprising 21% of total annual consumables expenditure of A\$130 million for the project, which in turn comprises 37% of total expenditure. This indicates that the aggregate of gas supply costs; GGP gas transmission costs; and costs associated with the gas lateral, make up approximately 7% of total expenditure.

Ventnor is not aware of the precise quantity of gas used for power generation compared with that used for the production of hydrogen; however depending on load factor and generation efficiency, generation is likely to account for approximately 50% of the total gas used.

4.2.3 Cawse Nickel

The Cawse nickel project is located 50 km north-west of Kalgoorlie and is another of the new generation projects based on a large lateritic ore-body. The project, which produced its first nickel in January 1999 was developed by Centaur Mining and Exploration Ltd, and was only designed to produce 9,000

⁽¹⁶⁾ Anaconda website – www.anaconda.com.au – Presentation to Secured Creditors – 15 March 2002



t/a of nickel metal compared with 45,000 t/a for Anaconda's Murrin Murrin plant. It is, therefore, in the nature of a demonstration plant, and is reliant on significant expansion to achieve full viability.

Anaconda entered into a conditional agreement with Centaur during 2000 to purchase a strategic shareholding, and to complete a feasibility study into the expansion of the plant. However, these plans were abandoned when Centaur was placed into administration in March 2001. The Cawse operation was subsequently purchased by the OM Group, a producer and marketer of metal-based speciality chemicals and powders.

Cawse appears to be regarded as the most viable of all three lateritic nickel producers (Murrin Murrin; Cawse; and Bulong) - at least in a technical sense. Ore is treated with sulphuric acid at high temperature and pressure in a purpose-built autoclave. Sulphuric acid is purchased from the Kalgoorlie nickel smelter (a distance by road of approximately 100 km) rather than being produced on site as for Murrin Murrin. The processing involves neutralisation and precipitation of a mixed metal hydroxide, then ammonia leaching, solvent extraction and electrowinning steps to produce nickel metal and cobalt sulphide.

The power and steam requirements of the operation are provided by a gas-fired cogeneration plant consisting of four 3.5 MW gas turbine generators, four heat recovery boilers and a desalination unit. The power station was purchased by AGL in November 1998. Gas is supplied from the GGP through a 35 km lateral. The Office of Energy⁽¹⁷⁾ reports that Centaur contracted with the Apache led Harriet Joint Venture for 4.5 TJ/d of gas.

4.2.4 AlintaGas

In February 1997 AlintaGas was awarded the mandate for the reticulation of natural gas within the Kalgoorlie-Boulder area. Supply to initial customers commenced during the following year and has grown each year since with further extensions of the distribution system.

Ventnor understands that the total volume supplied to commercial and residential consumers in the area is less than 0.5 TJ/d or approximately 0.5% of total GGP throughput volume. Competition to reticulated gas is provided by LPG, and Ventnor understands that AlintaGas has continued to experience difficulty in winning market share from LPG. There is a competitive market

⁽¹⁷⁾ Office of Energy – Energy Western Australia 2003



in regional Western Australia for the supply of LPG in bulk and bottled form. Suppliers include Wesfarmers Kleenheat, Origin Energy and BOC.

AlintaGas' published charges for residential and business consumers in Perth and Kalgoorlie are compared in Table 3 below:

Table 3
AlintaGas Prices⁽¹⁸⁾

	Perth ¢ / unit	Kalgoorlie ¢ / unit
<u>Residential</u>		
First 12 units	6.85	6.04
Next 24 units	4.44	6.04
Over 36 units	3.26	6.04
<u>Business</u>		
First 100 units	7.08	5.38
Over 100 units	5.64	5.38

Note: 1 unit of gas is equivalent to 3.6 MJ

On the basis of a delivered gas price of approximately \$4.75 at the Kalgoorlie outlet, AlintaGas' cost of gas would be 1.7 cents/unit. Of this the transport component would be approximately 1.00 cents/unit.

It is interesting to note that Wesfarmers Kleenheat reticulates LPG within the township of Leinster, which is located in close proximity to the GGP.

4.2.5 Esperance Power Supply

On 28 February 2003 the Minister for Energy announced that independent power producer Burns and Roe Worley Developments would shortly commence work on the construction of a new gas fired power station in Esperance and a 340 km gas pipeline from Kambalda to Esperance. The new power station, expected to be operational in early 2004, will replace existing diesel plant owned and operated by Western Power and the Esperance Port Authority.

⁽¹⁸⁾ AlintaGas website – www.alintagas.com.au – Prices from 1 July 2002



The agreement has been reached as part of Western Power’s regional power procurement programme, under which competitive alternatives have been sought to high-cost remote diesel generation, which has required large and continuing government subsidies. GGT expects the project to add “just a few TJ/d of incremental load”.⁽¹⁹⁾

4.2.6 Summary

There are no published figures for the breakdown of contracted capacity on the GGP on a shipper-by-shipper basis, or for gas off-take at individual outlet points. The December 2002 submission by GGT to the Acting Gas Access Regulator cites MDQ for the GGP in 2000 as 108.4 TJ/d, dropping to 98.2 by 2006. Total gas throughput is projected to increase from 77.4 TJ/d in the same period to 80.6 TJ/d indicating an improvement in load factor from approximately 71% to 82%.

The information provided in the preceding sections on each individual shipper, makes reference to Office of Energy data on contracted gas supplies. These are summarised in Table 4 below:

Table 4
GGP – Contracted Gas Supply

	(TJ/d)
<u>Initial Customers</u>	
BHP-Newman	7.0
WMC	37.0
Normandy	<u>18.5</u>
	62.5
<u>Third Parties</u>	
Plutonic	3.0
Anaconda	13.0
Cawse	4.5
AlintaGas	<u>0.5</u>
	<u>21.0</u>
TOTAL	<u>83.5</u>

These figures correlate closely with GGT’s recent throughput outlook, and provide a reasonable indication of total throughput by Initial Customers compared with Third Parties.

⁽¹⁹⁾ GGT submission to Acting Gas Access Regulator – December 2002



5.0 DOWNSTREAM MARKETS

Criterion (a) of the coverage tests within the Code require that:

“Access (or increased access) to Services provided by means of the Pipeline would promote competition in at least one market (whether or not in Australia) other than the market for the Services provided by means of the Pipeline”.

As indicated in Section 1.0, the State Agreement incorporates an access regime specifying the terms under which third parties can gain access to the GGP. The question, therefore, becomes whether increased access which might result from coverage of the GGP, would promote competition in a downstream market to a greater extent than the State Agreement regime.

Section 4 has described the existing contractual commitments for capacity on the GGP – both from the Initial Customers which were responsible for the development of the GGP; and from third parties which contracted for capacity after the GGP was constructed. Ventnor understands that all of the third party arrangements – with the exception of the contract for the Esperance power supply - predate the coverage of the GGP under the Code, which formally commenced on 1 January 2000.

The purpose of this section is to identify relevant markets, downstream from the services provided by the pipeline, where competition might be promoted by increased access to the GGP. Comment is also provided, on the extent to which such increased access might promote competition in any of these markets.

5.1 Market for Gas

AlintaGas transports gas for distribution and sale to commercial and residential customers in the Kalgoorlie-Boulder area. As commented in Section 4, AlintaGas' quantities comprise approximately 0.5% of total gas transported in the GGP and can probably be regarded as trivial. The potential size of this market is strictly limited by the relatively small size of the Kalgoorlie/Boulder community and the costs associated with converting customers over to natural gas.

A relevant comparison is the Perth and South-West residential and commercial market which in 2000/01 comprised only 17% of AlintaGas deliveries (ie. 29 TJ/d out of average throughput of 170 TJ/d). This is notwithstanding a population well in excess of 1 million (approximately 30 times that of



Kalgoorlie) and significantly greater population densities. AlintaGas contributes only about 30% of total DBNGP throughput.

The commercial and residential gas market in the Goldfields, including Kalgoorlie/Boulder, is also supplied – in bottles or in bulk – by a number of LPG suppliers, including Wesfarmers Kleenheat, Origin Energy and BOC. As previously indicated, the competitiveness of LPG is demonstrated by the fact that a number of large energy users in Kalgoorlie (eg. Kalgoorlie Regional Hospital) have not converted to natural gas. Furthermore, Wesfarmers Kleenheat provides an LPG distribution system in the town of Leinster, which is in close proximity to the GGP.

LPG is produced for the Western Australian market by Wesfarmers, which operates a plant at Kwinana to extract the LPG content of natural gas transported down the DBNGP. LPG is also produced by the BP oil refinery at Kwinana, as a process by-product.

Information available about the specific operations of GGP shippers is insufficiently detailed to provide a breakdown of gas use by each shipper. However, from an examination of company reports and website material, Ventnor has only been able to identify one application – Anaconda's use of gas for hydrogen production - where gas is used for process requirements for its inherent qualities. Ventnor believes that this, plus AlintaGas sales in the Kalgoorlie/Boulder area comprise only 6-7 TJ/d - which is borne out by GGT's statement in its Access Arrangement Information submitted to the Regulator in 1999, that "... At the time of writing, over 90 percent of all gas transported by the Goldfields Gas Pipeline is ultimately used for fuel for gas turbines which provide motive power for electricity generation".

Conclusions

- Natural gas has limited use along the GGP corridor for its inherent qualities – whether for process applications or domestic use;
- There is a strong and competitive market for LPG (in bulk or bottled form), which provides an effective alternative to natural gas;
- AlintaGas' decision to reticulate natural gas in the Kalgoorlie-Boulder area was made in 1996/97, under the State Agreement access regime;
- The transport component comprises less than 20% of AlintaGas published tariffs for Kalgoorlie/Boulder, which are not out of line with tariffs for the Perth metropolitan area;



- The GGP does not appear able to significantly influence the market in respect to gas delivered for use as gas within the Kalgoorlie/Boulder area;
- It is difficult to see how increased access to the GGP might promote competition in the gas market along the GGP corridor.

5.2 Market For Electricity

In Ventnor's view, consideration of the existence or otherwise of an electricity market needs to be separated into two categories:–

1. “stand-alone” electricity generated for remote mining and processing ventures; and
2. electricity generation which is connected to the SWIS.

These are considered below:

5.2.1 *Electricity for Remote Ventures*

In Table 5 Ventnor identifies what it understands to be the principal significant mining and processing operations within reasonable proximity to the GGP. Table 5 does not include operations at the southern end of the GGP which are accessible to the SWIS. Summary information – to the extent available from published sources and websites – is presented on the source and scale of electricity requirements for each operation. This indicates that diesel fired generation is still used for a significant number of the remote ventures within reasonable proximity to the GGP.

Those mining ventures where gas is used for the generation of electricity, are listed in Table 6. With the exception of Marillana Creek and West Angelas (iron ore), and the Murrin Murrin and Cawse (nickel) projects, all ventures were in existence prior to the construction of the GGP and have converted from diesel fired generation.



VENTNOR CONSULTING GROUP

Table 5
Remote Mining/Processing Operations in Proximity to GGP

Operation	Company	Commodity	Distance Along GGP (km)	Distance From GGP (km)	Electricity Source	MW	
Robe River	Robe River Iron Assoc.	Iron ore	50	10	Transmission line	(*)	Robe generates in its own gas fired station at Cape Lambert and transmits to minesite by 132 kV transmission line
Paraburdoo	Hamersley Iron	Iron ore	300	10	Transmission line	(*)	Hamersley generates in its own gas fired station at Dampier and transmits to minesites by 220 kV transmission line.
Channar	HI/Chinese	Iron ore	330	30	Transmission line	(*)	Hamersley generates in its own gas fired station at Dampier and transmits to minesites by 220 kV transmission line.
West Angelas	Robe River Iron Assoc.	Iron ore	400	60	Transmission line	(*)	Brought onstream in mid-2002 with production at 8 Mt/a. Electricity supplied by Hamersley from Dampier.
Yandi	BHP Iron Ore	Iron ore	400	80	Diesel	(*)	Mining commenced in 1992 and has increased to 25 Mt/a
Marillana Creek	Hamersley Iron	Iron ore	400	80	Transmission line	(*)	Mining commenced in 1998 and has expanded to 15 Mt/a
Newman	BHP Iron Ore	Iron ore	520	50	Gas	105	BHP Iron commissioned new gas capacity in 1996 to replace 66 MW of diesel capacity. Purchased by Duke Energy in early 1999.
Plutonic	Barrick Gold	Gold	702	19.2	Gas	20	Original diesel sets were replaced by gas fired plant in 1997
Fortnum	Perilya Mines	Gold	700	100	Diesel	<10	The Fortnum mine closed in 2001 after operating for 8-9 years at a rate of 800,000 tpa



VENTNOR CONSULTING GROUP

Operation	Company	Commodity	Distance Along GGP (km)	Distance From GGP (km)	Electricity Source	MW	
Wiluna	Normandy (Newmont)	Gold	863	8	Gas	10	10 MW diesel power station converted to gas firing in 1997
Jundee / Nimary	Normandy (Newmont)	Gold	863	45	Gas	13.2	14 MW diesel power stations replaced with 13.2 MW gas fired plant in 1997
Mt Keith	WMC	Nickel	946	8.1	Gas	38	WMC owned and operated diesel plant at Mt Keith from 1993 to 1996 when it commissioned the new gas fired station. This was sold to Southern Cross Energy in early 1999.
Darlot	Barrick Gold	Gold	970	60	Diesel	<10	Commenced operations in 1995. Acquired by Barrick in 2001. Produced 145,000 oz in 2002.
Bronzewing	Normandy (Newmont)	Gold	980	40	Diesel	15	Normandy increased to 100% ownership in 2000
Mt McClure	Normandy (Newmont)	Gold	980	30	Diesel	7.5	Mine acquired by Normandy in 1999 and now feeds Bronzewing plant
Cosmos	Jubilee Mines	Nickel	980	30	Diesel	<10	Commenced production in 2000. Open cut transition to underground.
Leinster	WMC	Nickel	1012	5.2	Gas	38	WMC owned and operated 128 MW diesel plant at Kalgoorlie, Leinster, Mt Magnet, Norsemen and Winderra prior to GGP commissioning in 1996. New gas plant sold to Southern Cross Energy in early 1999.
Agnew	Gold Fields Ltd	Gold	1012	5.2	Gas	-	Electricity now supplied from Leinster power station under contract. Electricity originally supplied from on-site diesels.



VENTNOR CONSULTING GROUP

Operation	Company	Commodity	Distance Along GGP (km)	Distance From GGP (km)	Electricity Source	MW	
Lawlers	Barrick Gold	Gold	1020	15	Gas	-	Power provided by on-site diesels until 2001. Now provided under contract from Southern Cross Energy's Leinster power station.
Tarmoola	Sons of Gwalia	Gold	1100	20	Diesel	<10	Commenced production approximately 1995. Current production rate approximately 110,000 oz.
Granny Smith	Placer Dome/Aurion Gold	Gold	1120	125	Diesel	17.5	Commenced production in 1990. Granny Smith deposit depleted and ore now supplied from Wallaby deposit. 2001 production approximately 350,000 oz.
Sons of Gwalia	Sons of Gwalia	Gold	1120	15	Diesel	<10	Production currently 50,000 oz.
Murrin Murrin	Anaconda / Glencore	Nickel	1142	85	Sulphur / Gas	58 / 20	Commenced commissioning in late 1999. Sulphur burning provides bulk of process electricity and steam.
Sunrise Dam	Anglo Gold	Gold	1120	125	Diesel	7.5	Commenced production in 1997. Mill capacity 2.5 Mt/a. AngloGold acquired in 1999.
Carosue Dam	Sons of Gwalia	Gold	1200	100	Diesel	<10	New processing facilities established in 2001. Current feed rate of 2.2 Mt/a.
Cawse	OMG - Cawse	Nickel	1230	35	Gas	14	Commenced production in 1999. Placed in administration in March 2001 and purchased by OMG.



Table 6
Remote Operations Supplied with Gas Fired Electricity

Operation	MW
BHP Iron Ore – Newman	105
Barrick Gold – Plutonic	20
Normandy – Wiluna	10
Normandy – Jundee/Nimary	13.2
WMC – Mt Keith	38
WMC – Leinster	38
Gold Fields Leinster – Agnew*	-
Barrick Gold – Lawlers*	-
Anaconda – Murrin Murrin	20
OMGroup – Cawse	14
TOTAL	258.2

* Supplied from Southern Cross Energy's Leinster facilities

On the basis of the gross assumption that these stations operate at a load factor of approximately 50% (assuming Newman load of approximately 30 MW), and conversion efficiency is approximately 10,000 kJ/kWh the amount of diesel displaced by these operations would be in the order of 293 million litres per annum (246,000 tonnes; or 11.3 PJ).

In all of these cases, gas is used predominantly for electricity generation, with the electricity being consumed directly within the mining and production processes. While in the case of BHP's Newman operations, electricity is also supplied to the town of Newman, this community only exists to serve BHP's iron ore operations.

In some cases the generation facilities are owned and operated by the companies themselves and in other cases, energy utilities such as Duke and TransAlta have purchased the facilities from the mining companies. In these latter cases the mining companies have entered into long-term take-or-pay contracts for the purchase of their ongoing power requirements.

Given that electricity is an essential production input, and these generation facilities are effectively captive to the mines and companies they serve, Ventnor believes that they do not individually or in aggregate comprise a market for electricity generated for remote mining projects.



Conclusions

- Electricity generated for remote mining and processing ventures is, in the main, captive to the mines and companies served.
- Gold Fields' Agnew Gold Mine was previously owned by WMC and continues to be supplied by the Leinster Power Station;
- Barrick Gold's Lawlers mine commenced purchases of electricity from Southern Cross Energy in 2001. This decision does not appear to have any relationship with GGP coverage under the Code in 2000;
- Decisions to adopt gas fired generation – with the exception of the Lawlers Mine – were made under the State Agreement access regime prior to 2000;
- Gas transported by the GGP does not supply a substantial number of the remote ventures within reasonable proximity to the GGP;
- In Ventnor's view it is hard, in any event, to categorise the generation of electricity for remote mining and processing projects as a market in which competition might be promoted by increased access to the GGP.

5.2.2 Electricity Connected to the SWIS

Both WMC and Normandy developed power generation facilities in the Kalgoorlie/Kambalda region, to provide electricity to operations which were previously supplied – and could still be supplied – from the SWIS.

Table 7⁽²⁰⁾ shows SECWA/Western Power's sent out energy and electricity sold to customers in the SWIS from FY 1993 to 1999. The average increase in sales from 1993 to 1999 was just over 2% pa.

As can be seen from Table 7, Western Power actually suffered a loss of sales between FY 1996 and FY 1997. This coincided with the completion of the GGP and the commissioning of 190 MW of privately owned gas turbine generating capacity in the Kalgoorlie/Kambalda area by WMC and Normandy.

⁽²⁰⁾ Western Power Corporation – Annual Reports, 1995 to 1999



Table 7
Western Power Sent Out Energy and Electricity Sold to Customers

Year Ending June 30	Energy Sent Out (GWh)	Sold to Customers (GWh)
1993	9,866	9,047
1994	10,485	9,607
1995	11,163	10,196
1996	11,661	10,688
1997	11,313	10,309
1998	11,543	10,521
1999	11,856	10,868

The SWIS network extends from Albany in the south, to Kalbarri in the north, and east to Kalgoorlie. The principal generation centres are at Collie – the State’s only operating coalfield – and Kwinana, near Perth. Total installed capacity for Western Power amounts to 3150 MW. Fuel sources for Western Power generation comprise coal (70%) and natural gas via the DBNGP (30%)⁽²¹⁾.

The 220 kV transmission link between Collie and Kalgoorlie was completed in September 1984 and its capacity enhanced over time to meet growth in Eastern Goldfields power demands. Data produced by Western Power⁽²²⁾ in December 1995, and presented in Table 8, shows a rapid build-up of electricity supplied by Western Power to consumers in the Eastern Goldfields after completion of the 220 kV transmission link.

Table 8
Western Power
Electricity Sales to the Eastern Goldfields

Year (ending June)	Energy Supplied GWh	Peak Load MW
1986	431	62
1987	501	70
1988	618	95
1989	808	118
1990	996	146
1991	979	127
1992	1012	145
1993	1052	139
1994	1210	169
1995	1310	180

⁽²¹⁾ Western Power – Annual Report 2001

⁽²²⁾ Western Power – Electricity Demand Forecasts – 1996 to 2005 (Dec 1995)



This is the last year for which Western Power produced segmented information for the Eastern Goldfields. Forecasts made at the same time for the following years are presented in Table 9.

Table 9
Western Power
Forecast of Electricity Sales to the Eastern Goldfields

Year (ending June)	Energy Supplied GWh	Peak Load MW
1996	1537	205
1997	539	65
1998	445	66
1999	437	64
2000	433	64

This indicates that Western Power expected to lose almost 1,000 GWh of sales to the Eastern Goldfields (and 140 MW of peak demand) as a result of the commissioning of the GGP and the WMC and Normandy power stations.

In fact Western Power's Annual Report for FY 1997 makes specific reference to a reduction in sales of 2.5% (sent out power of 11861 GWh, compared to 12183 GWh) due to the loss of major Eastern Goldfields customers. This reduction in sales came in a period when an average increase in sales of approximately 5% had been achieved by Western Power in each of the previous three years. It should be noted that the reduction in load shown in Table 8 is larger than the amount of power required from the WMC and Normandy stations by way of replacement, because of high losses on the transmission line to Kalgoorlie.

The data also demonstrates that the Eastern Goldfields transmission link had the capacity in 1995 to deliver a peak load of 180 MW, and possibly 205 MW, from Muja. Ventnor understands that Western Power continues to supply peak loads in the Eastern Goldfields of approximately 80 MW. This indicates that the link has substantial unutilised capacity at the present time.

It is important to note that SECWA, Western Power's predecessor until January 1995, was a vertically integrated gas and electricity monopoly in Western Australia. SECWA:

- owned all generation connected to the SWIS;
- owned and controlled the transmission and distribution systems;
- owned and controlled the DBNGP;



- was the sole contracting entity for North West Shelf Gas;
- was the sole retailer of both electricity and natural gas.

This monopoly position, and the high prices SECWA demanded from mining industry customers, provided the primary impetus for the development of the GGP and the associated power facilities.

On 1 January 1995 a series of energy reforms took effect which included:

- establishment of Western Power and AlintaGas as separate corporatised electricity and gas businesses;
- disaggregation of the gas contract between SECWA and the NWSJVP;
- commencement of open access to the DBNGP;
- separation of all regulatory functions out of Western Power and AlintaGas.

It was not until 1 January 1997 that third party access was provided to the high voltage transmission system. The progressive introduction of access to the distribution system, commenced later that year and has progressed in a series of steps as follows:

- 1 July 1997 Average load > 10 MW
- 1 July 1998 Average load > 5 MW
- 1 January 2000 Average load > 1 MW
- 1 July 2001 Average load > 230 kW
- 1 January 2003 Average load > 34 kW
- 2005 Proposed full retail contestability

Notwithstanding the commencement of electricity deregulation in 1995, the phasing of open access and the lack of any substantial privately owned generating capacity meant that Western Power faced no serious competition within the SWIS. While WMC and Normandy had constructed a certain amount of excess generation capacity in their Kalgoorlie and Kambalda stations, these two companies did not see the retailing of electricity as their core business, and were focused primarily on supplying their own operations and those of associated companies. This, by itself enabled them to achieve significant cost savings, in comparison with SECWA/Western Power's monopoly pricing.



The gradual lowering of contestability thresholds, and the sale of Western Mining's electricity assets to SCE in late 1998, created the opportunity and incentive for some third party sales from the Kalgoorlie generators. Since 1998, TransAlta as operator and sales agent for GP and SCE, has managed to achieve a number of electricity sales, including:

- Perth Airport (approximately 10 MW) – Nov 1998 - 2000 (subsequently regained by Western Power);
- Water Corporation (5 sites);
- Fremantle Hospital
- Karrinyup Shopping Centre

Ventnor understands that current third party sales commitments are approximately 20 MW.

It is interesting to note that TransAlta has been unsuccessful in securing third party sales in the Eastern Goldfields region in competition with Western Power. Ventnor is aware, however, that prices have dropped substantially from levels in the order of 14¢/kWh prior to deregulation to current levels in the order of 8-9¢/kWh. One of the factors driving Western Power has been the importance of maintaining reasonable levels of utilisation of the Eastern Goldfields transmission line in order to amortise the capital costs.

A contributing factor has been the emergence of some additional generation competition from surplus capacity being marketed from the alumina refining operations of Alcoa and Worsley. This amounts to approximately 50 MW, giving a total of 80 MW of generating capacity currently available for third party sale.

GP and SCE face a number of significant cost disadvantages compared with Western Power, Alcoa and Worsley. These include:

- high cost of gas transmission;
- small scale generation;
- low efficiency of open cycle gas generation.

This means that in order to make sales, GP and SCE are probably required to marginally price - despite the benefit of a 13% energy saving for supplying against the flow along the Eastern Goldfields transmission line into Perth and south-west markets.



As full retail contestability within the SWIS approaches, and the government's electricity reform programme becomes more tangible, the opportunity will arise for private investment in substantial new competitive generating capacity. In June 2002, the State government announced a two stage public power procurement process for new generation capacity – the first stage involving peaking capacity of 240 MW; and the second stage up to 330 MW of baseload capacity. AlintaGas and Alcoa have separately announced that they are examining the development of a number of gas fired co-generation units within Alcoa's alumina refineries to provide process steam, and electricity in competition with Western Power. Western Power is already constructing an energy efficient gas fired combined cycle power station of 240 MW at Kwinana, and is considering the construction of an additional similar unit. In Ventnor's view, any new base load private generation capacity is likely to be gas fired combined cycle or co-generation capacity.

These proposals can be expected to achieve a significant reduction in power costs within the SWIS – and as serious competition emerges, a possibly more significant reduction in electricity prices. Ventnor believes that GP and SCE will have increasing difficulty in these circumstances, in competing for third party electricity sales. This would apply to any logical expansion of these facilities, as well as to the existing generation facilities.

Gas for these new stations will be transmitted down the DBNGP – a pipeline with already more than six times the capacity and a higher load factor than the GGP – at tariffs at or below \$1.00/GJ (depending on the outcome of Epic's Supreme Court challenge to the Regulator's Draft Decision). Even if the scale economies of the DBNGP were ignored, and GGP tariffs were reduced to the level of the DBNGP charges – which would give fuel price parity for Goldfields generation compared with Kwinana generation – the Goldfields stations will face the disabilities of small scale and low efficiency.

Conclusions

- Western Power previously supplied the bulk of the power requirements now met by SCE and GP in the Kalgoorlie/Kambalda area;
- Electricity generated by SCE and GP in the Kalgoorlie/Kambalda area can be regarded as part of the wider SWIS electricity market;
- Surplus electricity transmission capacity exists between Kalgoorlie/Kambalda and Western Power's Muja power station which would enable bulk power supply in either direction;



- The SCE and GP generation facilities were developed at a time when SECWA/Western Power was a vertically integrated electricity monopoly;
- Reform and deregulation in the electricity industry is likely to see serious competition in generation and a move to full retail competition within the SWIS market.
- The costs of gas fired generation in Kwinana (or other locations in proximity to the DBNGP) will be significantly lower than those of SCE and GP, notwithstanding any tariff reductions which GGT might implement;
- The GGP – and the SCE and GP generation facilities in the Kalgoorlie/Boulder area – do not appear able to significantly influence the SWIS electricity market;
- Decisions by WMC and Normandy to develop gas fired generation in the Kalgoorlie/Kambalda area were made in the context of the State Agreement negotiations before the GGP was constructed.
- Third party electricity consumers have been supplied by SCE and GP under existing arrangements, but at marginal prices;
- Increased access to the GGP will not in Ventnor's view lead to the promotion of electricity competition within the SWIS.

5.3 Market for Energy for Remote Electricity Generation

To the extent that a market for energy exists along the route of the GGP, Ventnor considers that the relevant downstream market, as far as the GGP is concerned, would be the market for energy specifically for the generation of electricity in remote locations (ie. those not linked to the SWIS grid). Apart from the generation of electricity, by far the predominant use of energy in these remote areas of Western Australia, is the use of diesel for the operation of transport and mining equipment. For these applications gas does not currently offer an alternative energy source. Electrically driven equipment can in some circumstances substitute for diesel driven equipment.

The Office of Energy⁽²³⁾ provides the following breakdown of final energy use in Western Australia, by energy type:

⁽²³⁾ Office of Energy – Energy Western Australia 2003



Table 10
Final Energy Use
FY 2000/2001

Energy Type	PJ	%
Petroleum Products	204	44
Natural Gas	151	33
Electricity	76	16
Coal	19	4
Solar and Wood	14	3
Total	464	

It is interesting to note that electricity represented only 16% of final energy use compared with 44% for petroleum products. In 2000/2001 143 PJ of energy (predominantly petroleum products) was used in transport services and storage, and 57 PJ in primary and secondary industry. Of the 76 PJ used in the form of electricity, 47 PJ was used in the mining and manufacturing industry. On a Statewide basis, therefore, industry consumed considerably more petroleum products for non-transport requirements than electricity (57 PJ v's 47 PJ).

The conclusion which can be drawn from this, is that there is a very large market in Western Australia for energy in the form of petroleum products. Given the presence of a number of the petroleum majors, as well as independents, it would appear reasonable to conclude that the market for petroleum products is a highly competitive market.

As far as the generation of electricity in remote locations is concerned there are effectively only two alternative energy sources at present – diesel fuel and natural gas. LPG could theoretically be used, but to Ventnor's knowledge there are no LPG fired power stations in Western Australia. LNG has been promoted for some remote applications – particularly the Kimberleys – but a commercial supply arrangement has yet to be concluded.

The choice between natural gas and diesel for electricity generation is influenced by a number of factors. For gas fired generation:

- a gas supply contract is required, normally with a minimum five year term. Take-or-pay commitments apply with respect to the offtake quantities specified in the contract. Gas cannot be economically stored and supply commitments must, therefore, be sufficient to cover peak consumption requirements. (By contrast diesel can be purchased on much shorter term and more flexible arrangements. It can also be stored at relatively low



costs to provide a buffer for daily, weekly and seasonal fluctuations, and also for supply disruptions resulting from weather and other causes.)

- a contract for gas transmission capacity is also required. While GGT offers transmission contracts for as little as one year, there is a substantial price incentive for longer term contracts. Again, take-or-pay commitments apply. As with gas, capacity must be secured to cover peak consumption. (By contrast diesel is supplied on a delivered basis with no long-term take-or-pay obligations.)
- a lateral pipeline must be constructed to the mining location – whether by the mining company itself or by a supplier under long-term contract. The cost of the lateral must be capable of being amortised over the life of the project concerned.
- given that gas cannot be stored the project needs to make a decision as to whether to take the risk of supply disruption - with the potential for significant lost production or liquidated damages - or to provide for dual fuel capability within the remote power station. This means some duplication of investment in diesel and diesel storage facilities. It can also mean compromises in terms of generation plant selection and efficiencies.
- whereas diesel generation equipment in Western Australia is very widely used – and can, therefore, be readily relocated to another site - gas fired plant is not quite so universal in this regard. Capital costs for gas fired plant are, therefore, likely to be higher than for diesel, and salvage value lower.
- for reciprocating gas engines there is less versatility than for diesel plant in handling peak loads and load fluctuations. Gas turbines tend to experience greater efficiency losses at low output than diesel machines.

In making a decision between gas and diesel fired generation, companies must look beyond a direct comparison of delivered energy cost. They must consider:

- the uncertainties associated with their mining reserves and whether they can safely make the long-term commitments required for gas supply. The operating life of many mines is less than 8 years – at least as viewed at start-up – which is usually insufficient to offset the higher fixed costs and commitments associated with gas;
- the uncertainties associated with commodity prices (ie. for nickel and gold) and exchange rates;



- the financial capacity to support the additional investment and take-or-pay commitments required of gas, at the same time as funding mining and processing investment (operators in this sector are often companies with low capitalisation);
- the level of specialised professional support to implement and manage the more complex contractual arrangements required for gas generation;
- the cost penalties associated with securing gas and gas transmission capacity sufficient to meet peak requirements;
- the risks associated with supply interruption.

The delivered cost of gas, assuming full haul transmission along the GGP, and 100% load factor is approximately \$4.75/GJ (gas \$2.00, transport \$2.75). Depending on oil prices at the time diesel can be purchased in these remote locations for approximately 40¢/litre on an excise free basis. This equates to approximately \$10.40/GJ. Notwithstanding this large disparity, for the reasons mentioned above, gas fired generation is generally only selected for the largest mining ventures where ore reserves and company financial structures are sufficient to support the long-term take-or-pay commitments.

Table 5 in section 5.2.1. provides information on what Ventnor understands are the principal significant remote mining and processing operations within reasonable proximity to the GGP. This shows a total of ten remote operations which are supplied by gas, compared with ten which continue to be supplied by diesel. It is likely that there are an additional number of smaller projects within the GGP corridor, which Ventnor has been unable to identify. These would all be supplied by stand-alone diesel stations.

This tends to support the arguments presented earlier in this section, that despite gas having a substantial price advantage over diesel at GGP outlet points, there are a variety of other factors which are at least as important in determining a final choice between diesel and gas fired electricity generation. It also suggests a relatively low correlation between GGP's delivered gas price and the decision to choose gas fired generation.

It is interesting to note that Western Power continues to operate stand-alone diesel stations at Wiluna (1 MW), Laverton (1.7 MW) and Menzies (0.3 MW) to supply the electricity requirements of the local communities. Given that Western Power is not entitled to the diesel fuel excise rebate its incentive for switching to gas is considerably greater than for the mining companies.



In Section 5.2.1 Ventnor estimates that approximately 11.3 PJ of diesel has been displaced by gas in those operations which have converted to gas fired electricity generation. This compares with the total uses of petroleum products in Western Australia for 2000/2001⁽²⁴⁾, as follows:

Transport service and storage	143 PJ
Primary and secondary industry	57 PJ
Commercial, Residential etc.	4 PJ
TOTAL	204 PJ

Conclusions

- A market for energy specifically for remote electricity generation exists along the GGP corridor. There is competition between gas and diesel fuel for this market;
- The GGP has substantial unused (developable) capacity and there is, as a result, a strong incentive for the joint venturers to promote additional throughput;
- The diesel market itself is a large and highly competitive market in Western Australia. Competition from gas for remote electricity generation will have little if any impact on this market as it comprises a relatively small proportion of total diesel use;
- The choice between gas and diesel as the fuel for remote electricity generation depends on a number of cost elements – one of which is gas transmission – and a variety of other factors related to financial risk, complexity and anticipated length of operation;
- In view of the fact that there are still a significant number of diesel operated stations within the GGP corridor – some quite recent - diesel generation still represents a serious option for many remote mining and processing operations;
- All except one of the remote operations which selected gas fired generation, did so under the State Agreement access regime, and well before coverage of the GGP under the Code;
- In Ventnor's view it is unlikely that increased access to the GGP – i.e. beyond that provided under the State Agreement – will, of itself, lead to

⁽²⁴⁾ Office of Energy – Energy Western Australia 2003



the provision of competition in the market for energy for remote electricity generation.

5.4 Market for Iron Ore

It could be argued that relevant markets in which competition might be promoted by coverage of the GGP might include markets for the specific commodities produced in the operations supplied by the GGP. Iron ore produced by BHP Iron Ore's Newman operations is one such commodity.

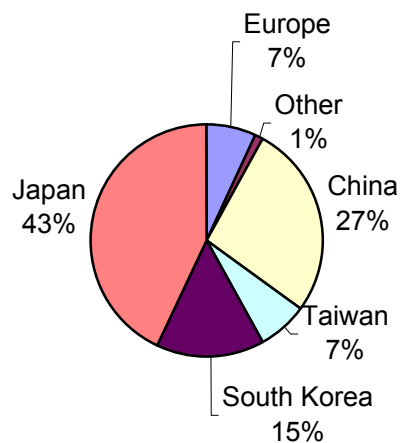
Resource Base

Western Australia occupies third place, after Russia and the Ukraine, for the extent of its defined resources of iron ore – 15.6% of the world's total⁽²⁵⁾ – with resources significantly exceeding those of competitors such as Brazil and Canada. Australia's "demonstrated reserve base" (USGS classification) amounts to 25 billion tonnes in terms of contained Fe.

Production

During 2001, Western Australia produced a total of 163 million tonnes⁽²⁶⁾, over 85% of which was shipped to East Asia. Total Australian production for the year was 176Mt. Figure 2 shows the destinations of these exports. Its share of world production increased to 17% during the year, up from 10% ten years earlier.

Figure 2
WA's Iron Ore Exports
Total Value A\$5.04 billion



⁽²⁵⁾ US Geological Survey Mineral Commodity Summaries – January 2002

⁽²⁶⁾ Dept. of Mineral & Petroleum Resources – Minerals and Petroleum Statistics Digest 2001



The growth in production of iron ore in Western Australia over the past ten years is shown in Table 11⁽²⁷⁾:

Table 11
Production Growth of Iron Ore – Western Australia

Year	Iron Ore Shipments (Mt)
1991	114.0
1992	108.0
1993	116.3
1994	124.3
1995	135.9
1996	133.6
1997	151.7
1998	142.7
1999	142.9
2000	158.1
2001	163.1

For the year 2001 production by company was:

BHP Iron Ore	68.5 Mt
Hamersley Iron	60.6 Mt
Robe River Iron	28.3 Mt
Portman Mining	4.5 Mt

Of the BHP Iron Ore production, 30.4 Mt was produced by its Newman operations.

In late 2000 Hamersley Iron's parent Rio Tinto, secured control of the Robe River operations, effectively consolidating control of Western Australia's iron ore industry in the hands of two companies.

According to AME Mineral Economics, Western Australia had the lowest iron ore production costs in the world, with costs having fallen 27% since 1997. Iron ore production is forecast by ABARE to increase from 176 Mt in 2001 to around 210 Mt by 2007.

⁽²⁷⁾ Dept. of Mineral & Petroleum Resources – Western Australian Iron Ore Industry (Sept.- 2002)



World Production

World iron ore production totalled 1045 Mt in 2001, with over 91% coming from ten countries⁽²⁸⁾. The largest of these are:

China	216.0 Mt
Brazil	209.0 Mt
Australia	163.1 Mt
Russia	82.5 Mt
India	76.0 Mt
Ukraine	54.7 Mt

China, Russia and the Ukraine largely serve the domestic steel industries of these countries. This leaves Brazil, Australia and India as the main contributors to world seaborne trade. Seaborne iron ore trade is estimated to have totalled about 454 Mt in 2001. Decline in domestic production of iron ore, particularly in China, is expected to see strong growth in the export market, virtually all of which is likely to come from Australia and Brazil. These two countries together account for 68% of the world's iron ore exports. The principal iron ore exporters in 2001 are listed in Table 12:

Table 12
Iron Ore Exporters

Country	Tonnage Mt	Percentage
Brazil	155.3	34
Western Australia	154.3	34
India	37.3	8
South Africa	23.5	5

Conclusions

- Western Australia and Brazil are the dominant players in the international iron ore business. Western Australia's share of market production has increased from 10% to 17% over the last 10 years;
- Western Australia has the lowest iron ore production costs in the world;
- BHP Iron Ore supplied 68.5 Mt out of a total of 163.1 Mt produced in Western Australia in 2001. Of this 30.4 Mt was produced by its Newman operations;

⁽²⁸⁾ Dept. of Mineral & Petroleum Resources – Western Australia's Iron Ore Industry (Sept.- 2002)



- Shipments of Western Australian iron ore have grown rapidly during the period in which the GGP has been in operation – i.e. from 133.7 Mt in 1996 to 163.1 Mt in 2001;
- The export value of iron ore from BHP Iron Ore's Newman operations is in the order of \$970 million (as a proportion of export value of \$5.2 billion in 2001);
- The costs of gas transmission to the Newman operations (at GGP's proposed Access Arrangement tariffs and assuming a 50% load factor for their operations) are likely to be in the order of \$15 million – or less than 2% of the export revenues from the Newman operations;
- A number of iron ore mines within reasonable proximity to the GGP have elected to obtain their electricity requirements from diesel fired generation, or for historical reasons are supplied by high voltage transmission lines from coastal power stations;
- Increased access to the GGP will, in Ventnor's view, have no impact on competition in the international iron ore market.

5.5 Market for Nickel

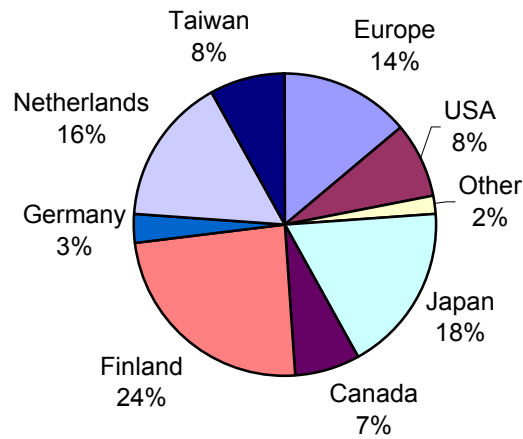
Production

Western Australia currently accounts for all of Australia's nickel production and 18% of world nickel production⁽²⁹⁾. The volume of production in 2001 was 182,000 tonnes of contained nickel, valued at \$2.07 billion. This represented an 18% increase in production over the previous year. All production is exported, with the destinations shown in Figure 3:

⁽²⁹⁾ Department of Mineral & Petroleum Resources – Mineral and Petroleum Statistics Digest 2001



Figure 3
WA's Nickel Exports
Total Value A\$2.07 billion



Source: DMPR

The growth in Western Australian production over the past ten years is shown in Table 13:

Table 13
Production Growth in Nickel

Year	Production '000t
1992	48
1993	55
1994	77
1995	101
1996	108
1997	123
1998	143
1999	122
2000	153
2001	182

Source: DMPR – Mineral and Petroleum Statistics Digest 2001



Of the total of 182,000 tonnes of contained nickel produced in 2001, WMC's operations at Kambalda, Leinster and Mt Keith were responsible for approximately 105,000 tonnes (or 57%)⁽³⁰⁾. Anaconda's Murrin Murrin operations contributed a further 25,000 tonnes (or 14%)⁽³¹⁾.

WMC's operations are all based on sulphide ores. Initial processing to concentrate stage takes place at the mine sites, with the concentrate converted to nickel matte in the Kalgoorlie smelter. Approximately two-thirds is converted to pure nickel metal in the Kwinana refineries.

WMC claims to account for approximately 9%⁽³²⁾ of world nickel production, and to be entrenched at the bottom of the production cost curve⁽³³⁾. It regards its principal overseas competition as Inco, BHP-Billiton, and Falconbridge.

Apart from WMC and Anaconda, other nickel producers in WA include:

- Cawse - lateritic operation producing nickel metal
- Bulong - lateritic operation producing nickel metal
- Emily Ann - sulphide operation recently developed by Lion Ore Australia (Nickel) Ltd. Produces concentrates
- Radio Hill - an underground sulphide mine owned by Titan Resources. Produces concentrate.
- Rav 8 - an underground sulphide mine owned by Tectonic Resources NL. Produces concentrate.

World Market

Almost 70% of all nickel production is consumed in the production of stainless steels, non-ferrous alloys, foundry and plating. According to an Anaconda presentation to creditors in March 2002⁽³⁴⁾, the stainless steel market has grown rapidly in recent years, showing a compound annual growth rate of 5.5% in the ten years 1990 – 1999 (data attributed to WMC and CRU).

⁽³⁰⁾ WMC Quarterly Statistical Supplement – Quarter ending 31/3/2002

⁽³¹⁾ Anaconda Quarterly Review – period ending 31/12/01

⁽³²⁾ Chairman's Address – WMC AGM 18/6/02

⁽³³⁾ WMC Nickel Operations Briefing – June 2002 – WMC website

⁽³⁴⁾ Anaconda website – www.anaconda.com.au



Major producers of refined nickel (as distinct from nickel contained in matte or concentrate) are listed in Table 14 below:

Table 14
Producers of Refined Nickel⁽³⁵⁾

Company	Share of World Production
Norilisk	19%
Inco	17%
Falconbridge	8%
BHP Billiton	6%
WMC	5%
Eramet – SLN	5%
Others	40%

International market prices experience significant volatility, evidenced by a comparison of average prices in 2000 (US\$3.92/lb) and 2001 (US\$2.70/lb)⁽²⁷⁾, and the low of US\$2.19/lb reached in October 2001. This resulted from the severe impact of the global slow-down, with Western World stainless steel production experiencing its biggest fall since 1982 (5%), at a time when nickel production increased by 6%. Japanese and US market demand suffered massive falls of 17.5% and 13% respectively.

ABARE projects nickel consumption to rise by 8% in 2003 with increased activity and also growth in the market share of stainless steel. Exports are expected to reach \$3.6 billion by 2003/04. On the other hand global supply is expected to be restricted due to the absence of capacity additions.

Western Australia's lateritic nickel producers rely heavily for their viability on revenue from by-product cobalt, the price of which has also collapsed – from a level of approximately US\$15/lb, to a price as low as US \$6.89/lb during 2002. Producers such as WMC, with operations based on sulphide deposits are less affected by cobalt prices. AME reported in early 2002 that of the sulphide producers, WMC had been the most successful in achieving continued cost reductions, with average nickel costs falling by 25% over the last five years.

⁽³⁵⁾ Dept. of Mineral & Petroleum Resources – Mineral and Petroleum Statistics Digests 2001 and 2001/02



Conclusions

- Western Australia accounts for 18% of world nickel production, with production increasing from 108,000 tonnes in 1996 when the GGP was commissioned to 182,000 tonnes in 2001;
- WMC accounts for 57% of Western Australian nickel production and approximately 9% of world nickel production. WMC claims to be at the bottom of the world cost curve. Nickel costs have fallen by 25% over the last five years;
- WMC is the fifth largest producer of refined nickel in the world;
- International market prices for nickel experience significant volatility, indicating that vigorous competition exists in this market;
- The value of nickel exports from Western Australia in 2001 was \$2.07 billion, but is forecast by ABARE to reach \$3.6 billion in 2003/04;
- Ventnor has calculated approximate GGP revenues from nickel producers (WMC, Anaconda and Cawse) using prices quoted in the GGP Access Arrangement, and assuming 70% load factor. These amount to approximately \$50 million per annum, or approximately 2.5% of total 2001 revenues from Western Australian nickel exports;
- By way of comparison, average world nickel prices dropped by more than 30% in US\$ terms between 2000 and 2001;
- On the basis of the above it is clear that the world nickel market is already highly competitive and Ventnor does not believe that increased access to the GGP would result in any increased competition within the international nickel market.

5.6 Market For Gold

Production

2001 was the fourth successive year of falling output from the Western Australian gold industry. From a level of 238 tonnes in 1997 production in 2001 dropped to 192 tonnes (6.2 million oz). Production quantities over the past ten years are shown in Table 15 below:



Table 15
Gold Production in Western Australia
(tonnes)

Year	Production
1992	182
1993	183
1994	193
1995	189
1996	221
1997	238
1998	231
1999	212
2000	199
2001	192

Source: DMPR

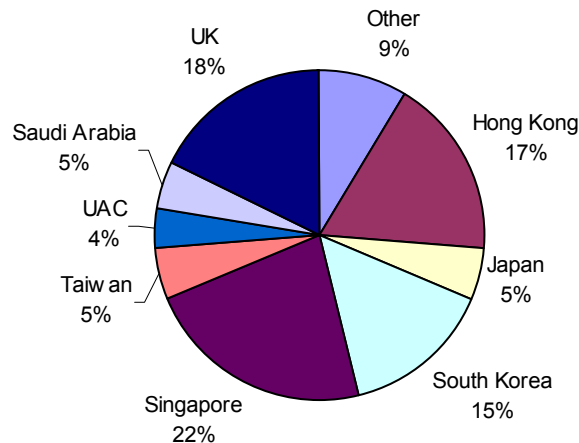
In 2001 Western Australian production accounted for 70% of Australia's, and 8% of world gold production⁽³⁶⁾.

The value of Western Australia's gold sales increased in 2001 by almost 5% to \$3,228 million⁽³⁶⁾, primarily due to the devaluation of the Australian dollar. Of this, exports amounted to \$2,838 million. Figure 4 shows the principal export destinations:

⁽³⁶⁾ Dept. of Mineral & Petroleum Resources – Mineral and Petroleum Statistics Digest 2001



Figure 4
WA's Gold Exports
Total Value A\$2.84 billion



Source: DMPR

Over half of Western Australian gold output in 2001 came from nine projects:

- Golden Mile – Kalgoorlie (KCGM – Newmont, Barrick) 22.7 tonnes
- St Ives (Gold Fields Limited) 14.2 tonnes
- Jundee-Nimary (Newmont) 12.6 tonnes
- Granny Smith (Placer Dome, Aurion Gold) 9.8 tonnes
- Bronzewing – Mt McClune (Newmont) 9.7 tonnes
- Plutonic (Barrick) 9.1 tonnes
- Sunrise Dam (AngloGold) 9.0 tonnes
- Kanowna Belle (Aurion Gold) 7.5 tonnes
- Boddington (Newmont, Newcrest, AngloGold) 7.1 tonnes

During 2001, there was continued rationalisation of the Australian gold industry. DMPR reports⁽³⁷⁾ that:

- from 1997 to 2001 the number of gold mines in Australia has dropped from 137 to 62;
- the number of gold mining companies has dropped from 86 to 35;

⁽³⁷⁾ Dept. of Mineral & Petroleum Resources – Minerals and Petroleum Statistical Digest 2001



- the average size of producers has increased from 117,000 oz/annum to 258,000 oz/annum.

Rationalisation within the industry has included:

- the merger between Barrick Gold and Homestake Gold to form the worlds second largest producer (but highest market capitalisation);
- the acquisition by Newmont Mining of Normandy (and Canada's Franco-Nevada Gold) to form the world's largest producer;
- the merger of Delta Gold and Goldfields to create Aurion Gold;
- the sale by WMC of its gold assets;
- the merger of treatment operations of particular mines (eg. Jundee and Nimary; Bronzewing and Mt McClure) to save costs.

Price

The international gold price at US\$271/oz, was 3% lower on average in 2001 than the previous year. It subsequently strengthened to a level as high as US\$389/oz in February 2003 - in response to concerns about the possibility of a war with Iraq. Over the long-term, however, ABARE expects gold prices to resume their downward trend towards US\$270 by 2007.

International Market⁽³⁸⁾

Goldfield Mineral Services estimated that in 2001 a total of 2604 tonnes of gold was produced world-wide. At the same time consumer demand for gold amounted to 3,235 tonnes. The largest consumer markets for gold were:

⁽³⁸⁾ World Gold Council website – www.gold.org



India	855 tonnes
USA	396 tonnes
Saudi Arabia	228 tonnes
China	213 tonnes
Gulf States	165 tonnes
South Korea	125 tonnes
Turkey	120 tonnes
Egypt	120 tonnes
Pakistan	119 tonnes
Japan	109 tonnes

Central bank sales of 468 tonnes contributed most of the gap between production and demand. Jewellery demand accounted for 2,840 tonnes (or 88%) of total demand, with private investment and industrial uses making up the balance.

Gold prices are influenced by a number of factors:

- physical demand for gold;
- sales by central banks and perceptions of the market with respect to future sales;
- political and economic uncertainty;
- forward sales of gold – or hedging.

Hedging has the effect of bringing future production immediately onto the market, and in recent years has resulted in downward pressure on gold prices. During 2000, for the first time, there was a net reduction in producer hedging, which had the effect of increasing the physical demand for gold.

The factors behind the reduction in hedging include:

- recent increases in US\$ gold prices;
- devaluation of local currencies has increased domestic denominated gold prices;
- industry consolidation has reduced reliance on hedging, and the unwinding of hedging positions.



Reductions in hedging, coupled with an agreement by central bankers (who hold almost 30,000 tonnes of gold) to limit sales of gold to 400 tonnes/year have brought some increased stability to the gold market in recent years.

Conclusions

- The value of gold production in Western Australia in 2001 was \$3,228 million;
- Western Australian gold production in 2001 accounted for 8% of world gold production. Almost 90% of this production was exported;
- Western Australian production has declined from a peak of 238 tonnes in 1997 to 192 tonnes in 2001;
- The gold industry has undergone substantial rationalisation, both in terms of ownership and the consolidation of treatment operations in recent years;
- The international gold price has experienced significant volatility in recent months increasing at one stage to a level of more than 40% above average US\$ prices for 2001;
- Gold price volatility relates to perceptions as much as the physical supply and demand of gold;
- Ventnor has estimated GGP transmission revenues from gold producers on the basis of GGP's published Access Arrangement tariffs. These are approximately \$20 million pa and represent less than 1% of the value of Western Australian gold production in 2001;
- On the basis of the above Ventnor does not believe that increased access to the GGP would result in any increased competition within the international gold market.



6.0 OPPORTUNITIES FOR LARGE SCALE PROCESSING

During 1999 and 2000 some conceptual work was carried out by Anaconda and others into the feasibility of establishing a large-scale processing complex in the North Eastern Goldfields. Ventnor does not have access to the full details of the specific projects proposed as part of this complex; however, a document sponsored by Anaconda – “Kick-starting the New Millennium, Developing the Goldfields and Mid-West – The Government’s Choice” – identifies a number of key components⁽³⁹⁾. It was argued by Anaconda that large scale processing could be viable in the region if the delivered cost of gas and other services could be substantially reduced. A complete discussion of downstream markets must, therefore, consider the prospects for such a processing complex proceeding.

The key components of the Anaconda concept are summarised below.

6.1 Specific Projects

6.1.1 Nickel

- Murrin Murrin II – expansion of the existing Murrin Murrin operation, owned 60% by Anaconda and 40% by Glencore. Nickel production 55,000 t/a; cobalt production 4,000 t/a.
- Mount Margaret – development by Anaconda and others of a new lateritic nickel resource south of Leinster. Nickel production to increase to 160,000 t/a (100,000 t/a Mount Margaret; and 60,000 t/a processed for others). Cobalt production 12,000 t/a.
- Cawse Expansion – Anaconda and Centaur envisaged expanding the existing Cawse operation by 50,000 t/a of nickel and 4,000 t/a of cobalt.

Ventnor understands that the development of an ammonia plant was incorporated as part of the Mount Margaret development, as the Mount Margaret ore requires different treatment to the Murrin Murrin ore. Substantial expansion of sulphuric acid capacity was also required. Anaconda went to the extent of obtaining environmental approvals for the first stage of the Mount Margaret project.

⁽³⁹⁾ Kick-starting the New Millennium – Table 3.1



When added to existing Australian nickel production capacity – assuming Murrin Murrin, Cawse and Bulong operate at nameplate capacity – the concept envisaged total production of 422,000 t/a (2-3 times existing production) or 40% of world production.

6.1.2 Magnesium

- Anaconda Magnesium – development of a 100,000 t/a magnesium processing plant in the Geraldton/Oakajee region, to process 400,000 t/a of magnesite produced from Anaconda leases at Murrin Murrin and Mount Margaret.

This project was expected to produce 30% of total world production of magnesium metal.

6.1.3 Phosphate Fertilisers

- Mt Weld – Anaconda and Wesfarmers CSBP envisaged processing 4 Mt/a of ore to produce concentrated phosphate fertilisers. The plant was to be located at the Mt Weld deposits, approximately 120 km east of Leonora (and approximately 50 km east of the existing Murrin Murrin operations).

The project was expected to produce sufficient ammonium, nitrogen and sulphur based phosphate fertilisers to replace imports into Western Australia and turn the State into a net exporter of phosphatic fertilisers.

Processing consisted of initial beneficiation – involving a combination of milling, magnetic separation, flotation and thickening – to produce 1 Mtpa of concentrate. One quarter of this was to be railed to the coast for further processing. The remaining three-quarters was to be processed with sulphuric acid, ammonia and ammonium sulphate to produce a range of fertiliser products.

The ammonia plant and expanded sulphuric acid capacity incorporated into the Mount Margaret processing complex are understood to have been essential components of this concept, as was low cost power generation. These derived much of their economic scale requirements from the proposed Mount Margaret nickel expansion.



6.1.4 Rare Earths

- Mt Weld – Anaconda and Lynas Gold proposed to develop the Mt Weld rare earth deposits (adjacent to Mt Weld phosphate) to produce tantalum and a range of rare earth concentrates.

The proposal was for mining and beneficiation to take place on-site, with the concentrate railed to Meenar (150 km east of Perth) for further processing. Low level radioactive waste was to be railed back to the mine for disposal.

Mt Weld Rare Earths was envisaged as producing approximately 12% of world supply of rare earths, which are key inputs in the electronics and glass industries.

6.1.5 Capital Investment and Export Revenues

The total investment and annual export revenues for the above industrial complex as estimated by Anaconda is set out in Table 16 below:

Table 16
Capital Investment and Export Revenue

Project	Capital Investment \$ billion	Annual Export Revenues \$ billion
Murrin Murrin I & II	2.2	0.8 – 0.9
Mount Margaret	1.4	0.7
Mt Weld	0.4	0.2 – 0.3 ⁽⁴⁰⁾
Magnesium	1.0	0.4 – 0.5
Cawse	1.1 – 1.3	0.4 – 0.5
TOTAL	6.1 – 6.3	2.5 – 2.9

6.2. Gas Requirements

“Kick-starting the New Millennium” estimated that the projects identified in Section 6.1 would require a total of 302 TJ/d⁽⁴¹⁾ of gas, as detailed in Table 17 below:

⁽⁴⁰⁾ Import replacement

⁽⁴¹⁾ Kick-starting the New Millennium – Tables 5.2 and 5.3



Table 17

Customer	Gas Requirement TJ/d
<u>Anaconda</u>	
Murrin Murrin I & II	44
Mt Margaret	100
Magnesium	100
Mt Weld Fertiliser	30
<u>Third Party Users</u>	
Mt Magnet town	3
Leinster town	7
Leonora town	4
Mt Eden Mine	2
Acacia Mine	5
Placer Mine	3
Laverton town	1
Spare	3
TOTAL	302

Of this a total of 100 TJ/d would have been required at Oakajee, north of Geraldton for power generation for the magnesium project. The balance of 202 TJ/d to be delivered inland is in the order of three times the remaining developable capacity of the GGP.

It should be noted that two world scale ammonia plants are currently proposed to be built on the Burrup Peninsula, near Dampier, by Burrup Fertilisers and Plenty River Corporation (with Agrium, Thiess and Krupp). Each of these plants has gas requirements in the order of 80 TJ/d, which would appear to be considerably larger than the ammonia plant envisaged as part of the Mount Margaret complex.

6.3 Geraldton to Mount Margaret Gas Pipeline (GEMM)

In order to provide sufficient low cost gas transmission capacity to meet the needs of the proposed processing complex, Anaconda included a proposal for the construction of a pipeline linking the DBNGP north of Geraldton with the Mount Margaret processing complex, and extending east as far as Murrin Murrin. GEMM was to have a diameter of 508 mm (compared with 356 mm for the GGP south of Newman); an operating pressure of 10.2 MPag; and a total length of 790 km. Its design capacity – with 5 compressor stations – was 306 TJ/d. Anaconda went as far as obtaining a Pipeline Licence for GEMM.



In its Quarterly Report for the period ending 31 March 2001, Anaconda commented that...

“the initial concept of GEMM was to provide lower gas prices into the Goldfields region than those available through the Goldfields Gas Transmission Line (“GGT”)”.

The Quarterly Report went on to say that:

- the 30% tariff reduction proposed in Offgar’s Draft Decision was a “welcomed development”;
- the reductions made the development of GEMM less viable but with a suitable base load it remained competitive with the reduced GGT tariffs;
- the regional loads in the North Eastern Goldfields would ultimately require a second pipeline into the region.

6.4 Regional Infrastructure

In “Kick-starting the New Millennium” Anaconda requested that the State and Federal governments provide financial support for the development of regional infrastructure as set out in Table 18:

**Table 18
Requested Government Infrastructure Support**

Infrastructure	State	Federal
GEMM Pipeline	<ul style="list-style-type: none"> • State owned infrastructure corridors • \$105 million investment 	<ul style="list-style-type: none"> • \$215 million in infrastructure bonds (or equivalent)
Rail links	<ul style="list-style-type: none"> • \$50 million investment for expansion • \$17.5 million for upgrade 	<ul style="list-style-type: none"> • \$114 million investment for expansion • \$17.5 million for upgrade
Water supply	<ul style="list-style-type: none"> • State owned infrastructure corridors • Easement approvals 	<ul style="list-style-type: none"> • Significant capital investment to facilitate construction of a pipeline from Officer Basin
Port	<ul style="list-style-type: none"> • Capital for upgrade of Esperance, Kwinana – or establishment of Oakajee 	<ul style="list-style-type: none"> • Capital for upgrade of Esperance, Kwinana – or establishment of Oakajee



In addition Anaconda sought substantial royalty relief as follows:

- Nickel – 2.5% royalty holiday
- Magnesite ores – removal of 5% royalty
- Phosphate ores – removal of 5% royalty
- Cobalt – royalty reduction to 1.5%
– 25% of cobalt royalties to a Cobalt Research Fund

This was to be matched in value by concessions from the Federal Government.

Anaconda argued that lack of government financial support for regional infrastructure would stop many of the proposed projects.

6.5 Conclusions

Anaconda developed and promoted what could be described as a “visionary concept” aimed at achieving the economies of scale necessary for large-scale processing in the North Eastern and Eastern Goldfields to be viable. The ingredients which were seen as essential to achieve this were:

- processing on a large scale;
- massive private capital expenditure;
- provision of infrastructure support services such as gas, power, water and transport on a large scale;
- on-site manufacture of reagents to avoid costly transport;
- significant process linkages between plants with reagents such as acid and ammonia being produced centrally and utilised in a number of process operations;
- capture of a significant proportion of the world market for particular commodities;
- substantial government investment in infrastructure;
- substantial government subsidies through royalty and other concessions.

In Ventnor's view, translating such a vision into reality would require all these elements being coordinated to come together essentially at the same time.



Unfortunately the scale of what was proposed has so far proven to be beyond the reach of Anaconda and there has been no indication that the substantial government support required would be forthcoming.

This appears to have been recognised in Anaconda's recent public statements which advise that:

- Anaconda's rare earth assets have been sold⁽⁴²⁾;
- further works on the Mount Margaret GEMM pipeline projects has been deferred⁽⁴³⁾;
- Anaconda will seek to divest its interest in the Officer Basin water project⁽⁴³⁾;
- Other activities at Mt Weld have been deferred⁽⁴³⁾;
- Exploration efforts are to focus on those tenements which can provide high-grade nickel feed to the Murrin Murrin plant⁽⁴³⁾;
- Tenement holding costs are to be reduced through relinquishment, sale or farm-out⁽⁴³⁾.

It should be apparent from the preceding discussion that the dream of a major chemical processing complex in the Northern and Eastern Goldfields requires far more than low cost gas transmission to be viable. It is also clear that at the scale of development required for viability, gas transmission requirements exceed the developable capacity of the GGP by 2-3 times, and at this level by-pass options such as GEMM provide a serious - and probably lower cost - alternative.

⁽⁴²⁾ Anaconda Quarterly Activity Report for the Period Ending 30 September 2001

⁽⁴³⁾ Anaconda Quarterly Activity Report for the Period Ending 31 December 2001



VENTNOR CONSULTING GROUP

Office of Energy Plan

http://www.energy.wa.gov.au/assets/images/energy_map.pdf



GOLDFIELDS GAS PIPELINE REVOCATION APPLICATION

APPENDIX 3: PRINCIPLES COMPARISON TABLE

**Submitted to the
National Competition Council**

March 2003

Table comparison of Competition Principles Agreement, Goldfields Gas Pipeline Agreement Act 1994 and National Third Party Access Code for Natural Gas Pipeline Systems (Schedule 2 to the Gas Pipelines Access (Western Australia) Act 1998 herein referred to as the Code

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(a) Wherever possible third party access to a service provided by means of a facility should be on the basis of terms and conditions agreed between the owner of the facility and the person seeking access.	Clauses 20(1) and 20(2) - the Joint Venturers must provide third party access to such spare or developable capacity as may be available from time to time on terms and conditions that are non-discriminatory, fair and reasonable.	Section 2 - access arrangements must contain terms and conditions that are fair and reasonable. The Service Provider and third party are free to agree to terms and conditions that differ from the access arrangement. Section 3 - the provision of the Reference Service must also comply with Section 8.
(b) Where such agreement cannot be reached, Governments should establish a right for persons to negotiate access to a service provided by means of a facility.	Clause 20(8) - third parties may apply to the Minister if they are unable to reach agreement with the service provider and thereafter the Minister may determine reasonable terms and conditions subject to the provisions of Section 20(9).	Section 6 - establishes a mechanism whereby disputes between third parties and service providers about terms and conditions of access can be submitted to an Arbitrator for arbitration, subject to the application of the terms of the Access Arrangement
(c) Any right to negotiate access should provide for an enforcement process.	Clauses 20(9) and 20(10) - sets out the criteria the Minister must have regard for in resolving a dispute. The matter may be referred to Arbitration if the Joint Venturers consider that any Ministerial direction is unreasonable or in respect of expansion, that it is not technically or economically feasible to expand capacity.	Section 6 - the arbitrator is bound to apply the provisions of the access arrangement in an access arbitration and specifically takes into account factors listed in Section 6.15. However, the Service Provider must comply with the Arbitrator's decision (Section 6.16).

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(d) Any right to negotiate access should include a date after which the right would lapse unless reviewed and subsequently extended; however, existing contractual rights and obligations should not be automatically revoked.	<p>Clause 20(8) - If the Third Party is unable to agree the terms of access for at least two months then recourse can be had to the Minister to resolve the conflict.</p> <p>The date after which the right to negotiate would lapse is the end of the State Agreement term.</p>	<p>Section 5.4 - the service provider must within 30 days of receiving an application for access reply to the third party. However, no minimum time limit is stipulated before which a dispute application is invoked.</p> <p>Section 3.17-20 – an access arrangement can be for any length of time but must include a date and/or specify circumstances for submission of revisions and when such revisions should come into effect.</p> <p>Section 2.25 protects pre-existing contractual rights.</p>
(e) The owner of a facility that is used to provide a service should use all reasonable endeavours to accommodate the requirements of persons seeking access.	Clause 20(4) - The Joint Venturers shall use all reasonable endeavours to develop the capacity of the Pipeline to accommodate third parties seeking access, including additional compressor stations and looping, subject to it being technically feasible and economically feasible.	Section 5.4 - the service provider must within 30 days of receiving an application for access reply to the third party whether capacity exists or doesn't exist and if so whether an investigation is required to determine if capacity can be made available. The Service Provider is not required to develop capacity at its own cost.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(f) Access to a service for persons seeking access need not be on exactly the same terms and conditions.	Clauses 20(1) and 20(2) - the Joint Venturers must provide non-discriminatory access to capacity and negotiate terms and conditions of third party access that are fair and reasonable and in accordance with certain guiding principles (Clause 22).	Section 2 - access arrangements must contain terms and conditions that are fair and reasonable. The Service Provider and third party are free to agree to terms and conditions that differ from the access arrangement but must include those matters provided for in Attachment A of the Code.
(g) Where the owner and a person seeking access cannot agree on terms and conditions for access to the service, they should be required to appoint and fund an independent body to resolve the dispute, if they have not already done so.	Clause 20(8) and 20(9) – The Minister resolves disputes in the first instance, subject to matters that remain in dispute being referred under Clause 37 to independent commercial arbitration provided under the Commercial Arbitration Act.	West Australian Gas Disputes Arbitrator is appointed by the Governor and is available to arbitrate on access disputes under the Code. The Arbitrator's conduct is in accordance with Section 6 of the Code.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(h) The decisions of the dispute resolution body should bind the parties; however, rights of appeal under existing legislative provisions should be preserved.	A Ministerial direction under clause 20(9) is appealable under Clause 37 by referring the matter to independent commercial arbitration under the Commercial Arbitration Act.	Section 6.24 - The parties to an arbitration are bound by the arbitrator's final decision unless the third party notifies the Arbitrator within 14 days of that decision that it does not intend to be bound by the decision. The Service Provider may seek to appeal a decision in relation to errors of law that has occurred in the arbitration.
(i) In deciding on the terms and conditions for access, the dispute resolution body should take into account:		
(1) the owner's legitimate business interests and investment in the facility;	Clause 20(9)(b) - the Minister shall have due regard for the legitimate business interests of the Joint Venturers. Additionally, under approved tariff setting principles, the owners are entitled to earn a commercial rate of return on all project capital commensurate with the business risk of the project.	Section 6.15(a) - the Arbitrator must take into account the Service Provider's legitimate business interests and investment in the Covered Pipeline. However, only that extent of capital investment that satisfies the criteria regarding the Initial Capital Base under Section 8 of the Code.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(i) cont.:		
(2) the costs to the owner of providing access, including any costs of extending the facility but not costs associated with losses arising from increased competition in upstream or downstream markets;	Clause 20(9) - the Minister must determine reasonable terms and conditions consistent with the tariff setting principles then applicable under Clause 22, which provide in Principle 2 that tariffs will be set to provide a commercial rate of return on all project capital.	Section 6.15(b) - the costs to the Service Provider of providing access, including any costs of extending the Covered Pipeline but not costs associated with losses arising from increased competition in upstream or downstream markets. Section 8, however, only allows the recovery of capital costs subject to certain economic criteria.
(3) the economic value to the owner of any additional investment that the person seeking access or the owner has agreed to undertake;	Under Clause 20(9), the Minister must determine reasonable terms and conditions consistent with the tariff setting principles then applicable under Clause 22, which provide in Principle 2 that tariffs will be set to provide a commercial rate of return on all project capital. Under Clause 20(9)(b), consideration of the legitimate business interests of the Joint Venturers would take into account the economic value of additional investment.	Section 6.15(c) - the economic value to the Service Provider of any additional investment that the Prospective User seeking access or the Service Provider has agreed to undertake, subject to various criteria, as to the manner and extent to which capital investment or efficiency gain may be retained as a benefit.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(i) cont.:		
(4) the interests of all persons holding contracts for use of the facility;	Clause 20(9)(c) - the Minister shall have due regard for the interests of all Third Parties holding contracts for transmission services in the Pipeline. However, under related principles Third Parties may derive the benefits of tariffs that are lower than contracted tariffs in the event of redetermination of tariffs.	Under Section 6.15(d) the Arbitrator must take into consideration the interests of all users.
(5) firm and binding contractual obligations of the owner or other persons (or both) already using the facility;	Clause 20(9)(c) - the Minister shall have due regard for the interests of all Third Parties holding contracts for transmission services in the Pipeline. Clause 20(9)(d) – the Minister shall have due regard for the interests of those in whose favour a determination has been made.	Under Section 6.15(e) the Arbitrator must give consideration to firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline.
(6) the operational and technical requirements necessary for the safe and reliable operation of the facility;	Clause 20(9)(e) - the Minister shall have due regard for the operational and technical requirements necessary for the safe and reliable operation of the Pipeline.	Section 6.15(f) provides that the Arbitrator must take into account the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline.
(7) the economically efficient operation of the facility; and	Tariff setting principle 12 provides for redeterminations of tariffs at any time that tariffs do not promote the use of the pipeline or the efficient use of reserved capacity.	Section 6.15(g) provides that the Arbitrator must take into account the economically efficient operation of the Covered Pipeline.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(i) cont.:		
(8) the benefit to the public from having competitive markets.	The public interest in a competitive market is addressed by the requirement to construct 50% spare capacity in the GGP. This provides a strong incentive for the owners to promote the use of the pipeline.	Section 6.15(g) provides that the Arbitrator must take into account the benefit to the public from having competitive markets.
(j) The owner may be required to extend, or to permit extension of, the facility that is used to provide a service if necessary but this would be subject to:		
(1) such extension being technically and economically feasible and consistent with the safe and reliable operation of the facility;	<p>Clause 20(4) - The Joint Venturers shall use all reasonable endeavours to develop the capacity of the Pipeline to accommodate third parties seeking access subject to it being technically feasible and economically feasible to so develop the capacity of the Pipeline.</p> <p>Clause 20(6) - the Joint Venturers shall not be required to implement such proposals where it is not technically feasible or economically feasible for them to do so, having regard to the legitimate business interests of the Joint Venturers.</p>	Section 6.22(b) provides that the Arbitrator must take into account the extension is technically and economically feasible and consistent with the safe and reliable provision of the Service.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(j) cont.:		
(2) the owner's legitimate business interests in the facility being protected; and	Clause 20 – provides that access to the pipeline and pipeline expansion shall have regard for the legitimate business interests of the owners.	Section 6.22(c) provides that the Service Provider's legitimate business interests are protected.
(3) the terms of access for the third party taking into account the costs borne by the parties for the extension and the economic benefits to the parties resulting from the extension.	<p>Clause 20(7) – provides that third party access shall be provided have regard to the allocation of cost, third party access and tariff provisions, and applicable billing (and metering) arrangements.</p> <p>Clause 20(9) – provides that in the event of arbitration in this respect, due regard must be given to the interests of all third parties holding contracts for transmission services, the interests of the Joint Ventureres, as well as the interests of others in whose favour a determination has been made.</p>	Section 6.23(c) provides that the terms of access for the Prospective User shall reflect the value to the Service Provider of the contribution made by the Prospective User.
(k) If there has been a material change in circumstances, the parties should be able to apply for a revocation or modification of the access arrangement which was made at the conclusion of the dispute resolution process.	Clause 29(1) – provides for the substitution, cancellation or variation of all or any provision of the State Agreement by mutual agreement of the parties to the agreement for the purpose of more efficiently or satisfactorily implementing or facilitating the subject matter of the agreement.	Pursuant to Sections 1.24 and 1.25 of the Code a Service Provider may apply for revocation of coverage of the pipeline, however, it is not necessary that such application follows a dispute resolution process.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(l) The dispute resolution body should only impede the existing right of a person to use a facility where the dispute resolution body has considered whether there is a case for compensation of that person and, if appropriate, determined such compensation.	Clause 37 defers to the Commercial Arbitration Act which would provide the appropriate guidance and discretion to the independent commercial arbitrator.	No consideration or direction is given to the matter of compensation.
(m) The owner or user of a service shall not engage in conduct for the purpose of hindering access to that service by another person.	Clause 20 - The Joint Venturers are obligated to provide non-discriminatory access to capacity on fair and reasonable terms and conditions. Third parties have recourse to the Minister and depending upon outcomes, subsequent recourse under Clause 37 to independent commercial arbitration under the Commercial Arbitration Act if the Joint Venturers are being unreasonable.	Section 5.4 - A Service Provider has to provide a reasonable response to a User requesting a service within 30 days of receiving a request for access and the User has recourse to arbitration if Service Provider is being unreasonable.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(n) Separate accounting arrangements should be required for the elements of a business which are covered by the access regime.	Clause 23(1) - the Joint Venturers shall maintain such records (including a separate set of accounts in accordance with accounting procedures to be agreed between the Minister and the Joint Venturers) in respect of the establishment, operation and use of the Pipeline as may be required to show to the Minister's reasonable satisfaction that transmission of gas through the Pipeline is available on a non-discriminatory basis at fair and reasonable prices.	Section 4.1(c) - A Service Provider in respect of a Covered Pipeline must establish and maintain a separate set of accounts in respect of the Services provided by each Covered Pipeline and generally under Section 4 a Service Provider is required to "ring fence" its business activities..
(o) The dispute resolution body, or relevant authority where provided for under specific legislation, should have access to financial statements and other accounting information pertaining to a service.	Section 23(3) - On the request from time to time of the Minister the Joint Venturers shall promptly provide the records maintained pursuant to this Clause and such information regarding the records as the Minister may reasonably require including, if requested by the Minister, an auditor's certification that the records have been properly maintained in accordance with this Clause.	Section 4.2 provides that the accounts must contain sufficient information and be presented in such a manner, which would enable verification by the Relevant Regulator of the calculation of the Reference Tariffs for Covered Pipelines and additionally under Section 5 of the Code gives broad information gathering powers to the Regulator.

Competition Principles Agreement Clause 6(4)	Goldfields Gas Pipeline Agreement Act 1994	Code
(p) Where more than one State or Territory access regime applies to a service, those regimes should be consistent and, by means of vested jurisdiction or other cooperative legislative scheme, provide for a single process for persons to seek access to the service, a single body to resolve disputes about any aspect of access and a single forum for enforcement of access arrangements.	<p>Clause 20 - provides that the Minister deals with disputes, prior to recourse to the Arbitrator.</p> <p>Clause 37 – provides for independent arbitration under the Commercial Arbitration Act.</p>	<p>West Australian Gas Disputes Arbitrator is appointed by the Governor and is available to arbitrate on access disputes under the Code. The Arbitrator's conduct is in accordance with Section 6 of the Code.</p>
	<p>GGP is subject to two overlapping access regimes which are not consistent in terms of implementation and effect. Multiple and conflicting dispute resolution processes exist.</p>	

nb: The sub-clauses in Clauses (i) and (j) in the Competition Principles Agreement Clause 6(4) have been renumbered for the purpose of clarity.

Ref: AW.LCD.LL-0729
C/f:

13 July 2001

Mr Alan Johnston
The National Access Regime Inquiry
Productivity Commission
PO Box 80
BELCONNEN ACT 2616

Dear Alan

**SUBMISSION TO THE PRODUCTIVITY COMMISSION IN RESPECT OF
REVIEW OF THE NATIONAL ACCESS REGIME**

Thankyou for the opportunity to contribute to the Productivity Commission's inquiry.

Goldfields Gas Transmission Pty Ltd (GGT) is the operator of the Goldfields Gas Pipeline (GGP) on behalf of the owners.¹ GGT has noted with interest the current inquiry into the National Access Regime being conducted by the Productivity Commission. Unfortunately, despite having been obliged to increase substantially the level of staff in order to accommodate the essential demands of regulatory compliance, GGT has not had the resources to keep fully abreast of the wealth of literature that this inquiry has generated. However, GGT would like to take this opportunity to make the following observations for your consideration.

As alluded to in the Commission's Position Paper in Section 3.1 ("What is the problem?"), the emphasis of the National Access Regime (the "Regime") has been determined by the view that "traditionally, government monopolies dominated service provision...". GGT would note that this paradigm is obvious in much of the wording and many of the requirements stipulated by the National Third Party Access Code for Natural Gas Pipeline

¹ The owners of the pipeline are an unincorporated joint venture currently comprising:

Southern Cross Pipelines Australia Pty Ltd	62.664%
Southern Cross Pipelines (NPL) Australia Pty Ltd	25.493%
Duke Energy International	11.843%

Ownership of the Southern Cross companies currently comprises CMS Gas Transmission of Australia (CMS) (45%), Australian Pipeline Trust (APT) (45%) and TransAlta Energy (Australia) Pty Ltd (TransAlta) (10%).

Systems (the Code). As elaborated upon below, the GGP was from inception owned and operated by private industry, and from this perspective, GGT would also draw your attention to the fact that the Regime which seeks to achieve certain reforms in the behaviour of corporatised (and largely privatised) government monopolies, also captures in its net, pre-existing infrastructure assets which already operate according to the principles sought by the Regime.

In terms of a submission to the Commission's review of the Regime, GGT offers for consideration the "real-world" outcome of the application of the Code to GGT. Under this process, GGT must incur not only the substantial costs of complying with the national Regime (currently amounting to in excess of \$1 million, with approximately half of this figure representing unavoidable fixed regulatory agency charges, with this being potentially less than half way through the process at this point in time). In addition, GGT is also exposed to substantially increased sovereign risk of mandatory and irrecoverable reductions in revenues.

While the "downside" of this example of application of the Code is significant (albeit primarily borne by the Service Provider), this might be acceptable (despite the implications for the economic viability of the Service Provider) from a macro-economic or social equity perspective, providing benefits in these areas outweigh the costs. However GGT contends that there is not only no significant offsetting benefit arising, but in fact in the case of the GGP the consequences of the manner in which the Code is being applied has negative implications for equitability and regional economic welfare (as well as international perceptions of sovereign risk in Australia). This is expanded upon in the attached submission.

GGT proposes that the example of the GGP, while predicated on reasonably unique circumstances as outlined below, provides a very suitable case-in-point which relates to the various deliberations referred to in the Commission's Position Paper in Section 3.1, particularly in respect to the sub-sections headed, "Does market power automatically attach to a natural monopoly?" and "The need for common sense".

Background

The GGP project arose out of the desire of the original owners to provide a cheaper source of energy to their own mining operations, and a State Government desire to promote regional development. Its construction followed the calling of expressions of interest by the Western Australian Government in March 1993. In mid 1993, the Government awarded the right to build the pipeline to a joint venture of Wesminco Oil Pty Ltd (Western Mining Corporation Holdings Ltd), Normandy Pipelines Pty Ltd (Normandy Poseidon Ltd) and BHP Minerals Pty Ltd – the original mining company proponents. The GGP was officially opened on 4th October 1996.

A State Agreement was signed between the Government and these joint venturers in March 1994. The State Agreement (one of many established for similar purposes in Western Australia) provided certain undertakings on the part of the Government to provide the joint venturers with security of investment, as well as imposing certain obligations on GGT to design for, and operate under the principles of open access to third party gas transportation. The original owners, having established these terms,

10 July 2001

subsequently sold their interests to the current owners, retaining certain rights of access for their mining operations which continue to be serviced by the pipeline, under negotiated terms of sale.

In November 1999, GGT submitted a proposed Access Arrangement and related documentation to the Western Australian Gas Pipelines Access Regulator (the Regulator) in compliance with the Code. On the 10th April 2001 the Regulator issued a Draft Decision outlining forty-nine proposed amendments to the submitted Access Arrangement for the GGP. The most significant of these is a proposal that existing (already substantially reduced from originally set) tariffs be reduced by a further 30%.

The period for public submissions to the Regulator concerning the Draft Decision, including any submissions that GGT might desire to be made available for public consumption, closed on the 13th July 2001.

The attached submission is an attempt by GGT under the limited recourse it has under the Code process, to address misconceptions which, while harmless enough in the "normal" course of events, have been demonstrated to have a substantial bearing upon the manner in which the Code is applied by the Regulator in respect to interpreting the desired outcome of (in the case of the GGP) re-regulation of tariffs.

Yours sincerely

David King
General Manager

Att. GGT_Submission_on_tariffs_10Jul2001.doc

10 July 2001

Goldfields Gas Transmission Pty Ltd
ACN 004 273 241

Level 8
Australia Place
15-17 William Street
Perth WA 6000

Submission on Supposedly High Tariffs on the Goldfields Gas Pipeline (GGP)

Goldfields Gas Transmission Pty Ltd (GGT) wishes to address the view being publicised by some parties as part of the current debate over tariff re-determination under the auspices of implementation of the National Code, that;

- (i) the price of delivered gas to the Goldfields region is high relative to other geographical locations, and,
- (ii) that substantially reducing gas transportation tariffs on the GGP will remedy this, improving relative competitiveness and removing a significant barrier to the development of new business in the region and hence will promote economic prosperity for the region and the State.

GGT submits that this notion is founded on a number of logical fallacies as discussed below.

- (1) That the price of delivered gas is independent of geographical location or specific pipeline design.

The tariff which a pipeline owner needs to charge in order to generate the revenue commercially required to justify investment in the first place, and then to subsequently stay in business, is a function of;

- (i) the cost of the pipeline (determined by length, required capacity and cost to install and operate), and,
- (ii) the gas volume it will transport (determined by the market it will serve initially, with consideration of future likely prospects for market growth to underpin provision of developable pipeline capacity).

In deriving a tariff equation, effectively; (i) the cost determines the numerator; and (ii) the volume determines the denominator. Making the numerator (ie. the cost) larger or the denominator (ie. the delivered volume) smaller, results in a higher tariff, and vice versa. It should also be noted however that this equation represents the overall average tariff requirement - in reality tariffs will vary depending upon the size and duration of a contract, recognising the value of commercial certainty in the same way as any other business might.

Considering the cost side of the equation;

- (i) As much as any other capital intensive business, pipelines have their own economies of scale. The smaller the market, the more limited or uncertain its prospects for growth, the further removed from the source of supply it is, the less favourable the economies of scale are going to be.

- (ii) Most (although certainly not all) gas pipelines tend to transport gas from a point of origin to a relatively well defined point of delivery, with little or no offtake before that end point. This simplifies the design of the pipeline and reduces the overall unit-transport cost that can be charged².

Unfortunately, the GGP does not enjoy this characteristic, having substantial offtake points all along its length.

- (iii) The GGP was conceived to supply gas to existing mines located between Mt Newman and Kalgoorlie in order to provide a cheaper fuel source than the diesel then being used. This was a logical step on the part of the mine site owners given that they also owned gas resources on the North West Shelf. In the capacity of custodian of the public interest, the State Government "stepped in" (to greatly understate the complexity of the process) and stipulated the minimum original and developable capacity which the pipeline would have to have. As a result, the GGP can, with some additional expenditure on capacity expansion, accommodate a higher throughput of gas than it might have otherwise been designed for. However, this capability came at an increased capital cost – a price that the mine owners had to pay in order to get the necessary Government approval to proceed with the GGP at all.

Considering the load (or volume of gas transportation) side of the equation;

In the event that demand arises, there are two generic approaches to how tariffs for the use of this expanded capacity could be developed. They are either on a marginal basis (where new Users pay based on the incremental cost of expanding to accommodate them), or on an average cost basis (where all Users see a tariff based on the new increased total cost being shared across the new increased total gas volume being transported)³. Whichever approach is adopted, the magnitude of any new tariff will be determined as a function of the new cost base and the new gas transportation volume which eventuates. Until both of these determinants are known, any resulting new tariff can only be estimated.

The current owners of the GGP would be very happy to see and accommodate demand for this additional transportation capacity. In fact GGT recently attempted to precipitate just such an increase in demand for gas transportation to the Goldfields. This was achieved by offering to the market a marginally priced tariff for any new project or new expansion of an existing project which was likely to go ahead within a defined period.⁴

Unfortunately, this initiative failed to capture any additional significant load. The total volume of new business for which interest was expressed was too small to underwrite any significant investment in expansion and the number of enquiries which proceeded to any form of commitment was even smaller. The conclusion which GGT draws is that gas demand in

² This is because some portion of the gas volume is only transported part way along the length of the pipeline, and hence a lower volume of gas remains to underscore the investment in pipe required to get to the final destination.

³ There are of course contractual considerations involving pre-existing rights of access, as well as tariffs, which must also be considered.

⁴ Hence the initiative was called an "Economic Development Tariff" (EDT) programme and included a defined period which was a necessary specification in determining correct capacity development and optimum expenditure phasing.

the Goldfields is highly price inelastic in respect to the cost of transporting gas. (This is explored further below).

(2) The relative impact of the transportation component in the delivered cost of gas.

The cost of delivered gas in the Goldfields (as elsewhere in Australia) will vary from customer to customer depending upon the size, duration and nature of the specific contracts into which they enter. Larger corporate businesses will negotiate their own gas supply and transportation contracts, or buy from a Gas Trader whose commission will be included in the delivered cost of the gas.

This variability (as well as commercial confidentiality associated with contracts and the fact that some of these are held by competing companies) makes direct comparison of the tariffs paid by these larger corporate customers within the region and between other regions problematic. However based on publicly available data, GGT has performed its own analysis of the relative contribution of the total cost of gas, and specifically the cost of gas transportation, within the total annual cashflow considerations of a major resource development project serviced by the GGP. For a relatively intensive gas consumer, these figures indicate that the cost of gas transportation represents considerably less than 5% of total operating costs.

At the other end of the customer spectrum, a breakdown of the publicised cost of gas delivered to the average small business or domestic household provides some insight into the relative significance of the cost of gas transportation in the overall price of gas.

According to the new price schedule published by AlintaGas, from 1 July 2001 the price of gas delivered to residential and business customers in Kalgoorlie is 5.86 and 5.22 cents per unit (including GST and the recent 3.5% price rise imposed by AlintaGas). This equates⁵ to a delivered cost of gas of \$16.27/GJ for residential customers and \$14.50/GJ for business customers.

As a rough guide, the price of purchasing gas in the North West Shelf area is around \$2.00/GJ. The current cost (under the published "A4" tariffs) to transport this gas the full length of the GGP to Kalgoorlie is somewhat under \$3.00/GJ, depending upon the specific customer's load factor. The balance of the cost of delivering the gas goes to the local distribution and marketing utility. The following table summarises this breakdown.

Breakdown	Residential Customer		Business Customer	
	Gas Purchase	\$ 2.00/GJ	12%	\$ 2.00/GJ
Transportation	\$ 3.00/GJ	18%	\$ 3.00/GJ	21%
AlintaGas	\$11.27/GJ	70%	\$ 9.50/GJ	65%
Total	\$16.27/GJ	100%	\$14.50/GJ	100%

⁵ On the basis that one "unit" equates to 1kilowatt hour, or 3.6 MJ.

10 July 2001

- (3) That reducing the cost of transporting gas will have any significant effect on the development of new business.

Market evidence, reinforced by the poor response elicited by the recent EDT offered by GGT, indicates that there are no new projects on any scale for which the cost of gas transportation is a critical determinant of viability.

To put the argument in the extreme, even if GGT were able to offer a gas transportation service **for free**, the evidence available to GGT indicates that this in itself would not precipitate one single new business venture proceeding. The only economic effects that would result would be to increase the profits of existing businesses and a possible loss of business for diesel fuel supply companies and diesel delivery drivers.

Obviously offering to transport gas at no cost is not a commercially viable option, however GGT would be most grateful to hear from the proponent of any new business who considers that the viewpoints offered in this section are erroneous. GGT would welcome the opportunity to explore how it might be able to work cooperatively to contribute to the viability of any new undertaking.

It should be noted that GGT is an open access pipeline and as such, actively seeks to promote and attract new business through offering gas transportation services at prices which are commercially defensible and fair and reasonable.

- (4) That the mandating of reductions in tariffs on the GGP will be conducive to development of other business or serve to promote economic prosperity.

Resource development significantly underpins the economy of Western Australia. It is vital to the economic prosperity of the Goldfields region. It is also a field of investment which is exposed to a multitude of technical and commercial uncertainties, and highly exposed to the vagaries of international economic fluctuations. When a project is successful, the Government is generally not slow to appropriate its full share of the proceeds. When it is not, it is the investors who are out of pocket.

In Western Australia, many developments have been facilitated by arrangements with the State Government. There are at least 63 State Agreements, enshrined in law and covering virtually every form of resource project and accounting for more than 70% of mineral production and 60% of all direct employment in mining⁶. This is not to say that all resource development has proceeded under the security of a State Agreement. However these agreements have certainly been instrumental in facilitating the bulk of resource investment in the State, reducing uncertainty and hence lowering the threshold at which the necessary investment funds are made available to developers.

Of course there will always be some investors who are prepared to accept higher levels of risk, but these investors demand higher rates of return, and there will always be fierce competition for these more limited investment funds from more speculative development promoters. Such investment sources cannot be relied upon to underscore the level of regional development that Western Australia demands.

The failure to give proper consideration to the GGP State Agreement by the State Regulator for Gas Pipelines Access under the national code, violates the very investment security which the agreement was intended to provide. The actions of the existing

⁶ Based on figures published by the Government of Western Australia in "In Agreement, How major developers obtain project security through State Agreement Acts", Department of Resources Development, August 1997.

owners, to whom the rights under the State Agreement were duly assigned at the time of purchase, have been entirely consistent with their obligations under that agreement. In contrast, the decision (albeit a draft at this time) issued by the State Regulator represents a denial of the undertakings provided by the Government and purported to afford specific investment securities over the whole of the originally agreed project life.⁷

The ramifications for other existing State Agreements, the credibility of future undertakings and assurances on the part of the State Government, and the medium to long term consequences for resource and infrastructure investment in this state remain to be seen. However, given the preceding appraisal of the lack of economic benefits which this decision brings, and comparing this to the negative consequences for investment certainty and State reputation, it is difficult to see how the Regulator's decision to propose substantial tariff reductions for the GGP can be conducive to either regional development or economic prosperity.

(5) That any significant reduction of tariffs and hence revenue to GGT is economically sustainable.

The original tariffs for the GGP were determined under State approved tariff setting principles. Included in the methodology were assumptions in regard to project life, pipeline costs, future gas demand forecasts and acceptable rate of return on the investment. Since then, tariffs have been discounted by some 25%.

The GGP Draft Decision, proposes to put a cap on the revenue which the GGP can earn by reducing the tariff which can be charged for its transportation services. This reduction is both substantial and has been set without regard (other than a superficial linkage in respect to setting a revised capital base) to the economic values upon which the investment was undertaken. Moreover, the Decision also proposes that, in the event that an increase in gas demand does materialise, and if GGP revenue were to increase to a value which still falls short of what it is being reduced from⁸, a further tariff reduction would be triggered.

It is obvious that the extent of the reductions from the revenue originally required to justify the construction of the GGP are very substantial. It is also clear that under the Regulator's proposal, this lost revenue could never be recouped, even in the event that significant gas demand in the Goldfields were to materialise. Leaving aside matters of acquisition cost to the current owners, it must be reasonably obvious what the impact of such measures must be on the economic viability of the project.

Conclusion

As a consequence of the views expressed above, GGT concludes that the tariff reductions being currently proposed in the Draft Decision are not only unwarranted and inequitable, they have been arrived at on a basis that is inappropriate to the specific history, circumstances and intended outcome. In fact it seems likely that the extent and nature of the tariff reductions proposed in the current Draft Decision are more likely to result in a stifled investment and a sustained economic downturn in the resource sector than in any measurable social or economic benefits.

⁷ Unless changed by mutual agreement.

⁸ ie. the proposed revenue reduction is 30%, the threshold for the trigger is if revenue reaches a 25% increase from the reduced value.

10 July 2001

While the intention of this submission is to address what appear to be fairly widely held misconceptions affecting all interested parties, GGT specifically requests the Regulator to re-evaluate the basis upon which he has previously formed a view in regard to tariffs on the GGP. Furthermore, GGT requests all interested parties to reconsider their own position as to the potential costs and benefits associated with the Regulator's recent Draft Decision.



GOLDFIELDS GAS PIPELINE REVOCATION APPLICATION

APPENDIX 5: "SEARCH FOR NEW GAS CUSTOMERS"

**Submitted to the
National Competition Council**

March 2003

SEARCH FOR NEW GAS CUSTOMERS

WITH CONSTRUCTION of the Pilbara-to-the-Goldfields gas pipeline moving ahead on schedule, a major priority for the pipeline manager, Goldfields Gas Transmission Pty Ltd (GGT), is to secure additional users of the \$450 million energy supply facility.

Companies directly involved in the GGT Joint Venture — Western Mining Corporation Ltd, Gold Mines of Kalgoorlie Ltd (Normandy Group) and BHP Minerals — have already committed to using 80 terajoules of gas per day, 50 per cent of the fully compressed capacity of the pipeline.

Now GGT is stepping up efforts to encourage other resource developers to tap into the benefits of the gas pipeline. GGT has undertaken public promotions and held talks with consulting groups, gas merchants and mining companies interested in operations along the pipeline route. The Joint Venture plans initially to install two compressor stations to service 1996 loads, but will add further compressor stations as pipeline loads increase.

Potential third-party clients include the Yakabindie, Honeymoon Well and Murrin Murrin nickel projects and myriad gold producers, including Marymia, Plutonic, Wiluna, Jundee, Bronzewing, Granny Smith and others around Kalgoorlie and Leonora.

GGT manager Bruce Ride said the pipeline's fundamental purpose was to provide lower-cost energy to the East Pilbara, Murchison, North Eastern

Goldfields and Eastern Goldfields in a reliable, safe and environmentally acceptable manner.

"While initially most of the gas committed for the pipeline will be used by the GGT joint venture participants at Newman, Mt Keith, Leinster, Kalgoorlie and Kambalda, tremendous scope exists for others to link into the gas pipeline system," he said.

Mr Ride acknowledged some gold producers with perceived short-term life mining operations were generally hesitant about committing themselves to building a lateral linking up to the main gas pipeline and investing in new power equipment.

However, where several small mines operated in the same area, it could be viable for companies to work together to generate electricity using natural gas. Companies also have the option of seeking the services of an independent power producer to generate electricity using gas transported in the Goldfields gas pipeline.

A set of gas transportation tariffs, based on a schedule approved by the WA Government, is publicly available to help third parties evaluate the economics of connecting to the pipeline.

Tariffs for transmitting gas through the pipeline are applied in a non-discriminatory way to the various gas customer categories. The basic tariff has two components, with the primary variables being the energy content of the gas and the distance the fuel is transmitted through the pipeline.

Different tariff schedules apply, depending on the term of the contract, with the GGT offering more attractive tariffs for longer-term contract users.

The following table illustrates tariffs for 11-15-year contracts at various take-off points along the pipeline, assuming gas is supplied to the GGT pipeline at Yarraloola.

Location	1997 Gas Transportation Tariff \$/GJ
Newman	1.55
Plutonic	2.00
Wiluna	2.40
Mt Keith	2.60
Leinster	2.76
Leonora	3.11
Kalgoorlie	3.64

Under the terms of the Goldfields Gas Pipeline Agreement Act, GGT is not allowed to buy or sell gas, only to supply gas transportation.

"With distillate prices now close to \$8 per gigajoule at several inland mining centres of the State, opportunities exist for resource companies to save money on their fuel bills," Mr Ride said.

"For miners in Kalgoorlie, a 10-15 per cent reduction in operating costs is expected. The economic incentive to convert to gas in the Pilbara is even greater." ■

consultation, and the initial "best route" has been changed significantly in a number of areas — in a few cases more than once, says Winterford.

Much of the pipeline route also traverses pastoral lease land and areas containing many Aboriginal sacred sites. Continuous negotiation with about 30 pastoralists and a greater number of Aboriginal communities has also been essential, not only during the planning of the route, but during construction.

"It is very important that the local communities are aware of what's going on and understand why this pipe is going through their land," says GGT's site-based construction liaison officer Allan Duncan.

"The cookies were pretty accepting once you explained what the gas was for, but I spent about three months travelling the proposed route explaining to the various Aboriginal custodians that



we were not out to find their sacred sites, just to avoid them." As a result, major anthropologically and archaeologically significant sites have been avoided. Construction work around the few archaeological sites which could not be bypassed was carefully managed to minimise disturbance outside the nominal right of way. ■

Thirsty work, left: Spending up to 12 hours a day in temperatures which can soar to 45°C, the crew can drink up to 10 litres of water each per day. X-ray specs, right: Each weld is checked using an X-ray crawler which passes through the pipe strings, exposing film wrapped around the joint.



GOLDFIELDS GAS PIPELINE REVOCATION APPLICATION

APPENDIX 6: DEVELOPMENT OF GORGON GAS

**Submitted to the
National Competition Council**

March 2003

THE DEVELOPMENT OF GORGON AREA GAS

I. J. Grose

Gorgon Development
Engineering Team Leader
Chevron Australia Pty Ltd
24th Floor QV1 Building
250 St George's Terrace
Perth WA 6000
email: ijgr@chevrontexaco.com

ABSTRACT

Australia will increasingly need to turn to natural gas to offset declining oil production and meet an expanding global need for clean energy. The Gorgon Development Joint Venture Participants, (ChevronTexaco/ExxonMobil/Shell), are poised to develop the significant Gorgon gas reserves located 130km offshore the North West Australian coast to help fulfil this need.

The Gorgon Development has access to extensive proved reserves of 13.8 Tcf and a development plan that can supply gas to a Barrow Island landfall at world competitive prices. Several concepts are being considered for development of the Gorgon reserves.

Technology will play a key role, with the extensive use of subsea production facilities and innovative LNG design concepts being considered. The focus is on a design that would have a low unit cost and also provide new benchmarks in safety and environmental performance.

The development of the Gorgon reserves could also facilitate the establishment of other gas-based industries in Western Australia and offers the opportunity for new gas-to-liquid (GTL) plants to lead Australia's transition to a gas-based economy.

The Gorgon Development is expected to attract nearly A\$4 billion investment for an LNG development and a further A\$2 billion for a major industrial gas consumer. Total export income could reach A\$2500 million per year for 30 years.

INTRODUCTION

The development of the Gorgon offshore gas fields is poised to become one of Australia's most significant resource projects. Located off the north west coast of Australia, the Gorgon Development is based on the largest gas field ever discovered in Australia and one of the world's premier hydrocarbon resources.

In 1998 development plans were based on a 2 LNG Train development onshore on the Burrup Peninsula, fed with gas from offshore facilities comprising subsea wells tied back via a Remote Hub Platform with a concrete gravity base. However, the LNG market contracted with the Asian economic crisis and the work was suspended pending the market return that is now occurring. During the intervening period, studies have continued on how to develop the Gorgon field economically in quantities tailored to potential market opportunities.

As a result, the Gorgon Development is now more capable of meeting both the demand for industrial natural gas users in Western Australia together with the larger requirements of an LNG export development. It is also expected to power Western Australia's next wave of industrial growth whilst delivering economic returns throughout the Australian economy.

Australia's gas economy

With declining supplies of domestic crude oil and rising fuel demand, Australia will need to increasingly turn to its energy strength - natural gas.

The Gorgon Development has the capacity to ensure Australia's position as a regional leader in clean energy - both as an exporter of LNG and a producer of gas for the next generation of gas-based fuels. The ingredients are already there:

- vast and growing reserves of natural gas;
- access to expanding energy hungry markets in the Asia Pacific region;
- a world demanding cleaner energy; and
- experience and skill in the development and execution of large resource projects.

Development ownership

The Gorgon Development is owned by an unincorporated joint venture consisting of three large international energy companies, collectively known as CTMS. ChevronTexaco with 4/7th interest, Shell Development (Australia) Pty Limited with a 2/7th interest and Mobil Australia Resources Company Pty Ltd. (a subsidiary of ExxonMobil) with a 1/7th interest. The Development is operated by Chevron Australia Pty Ltd

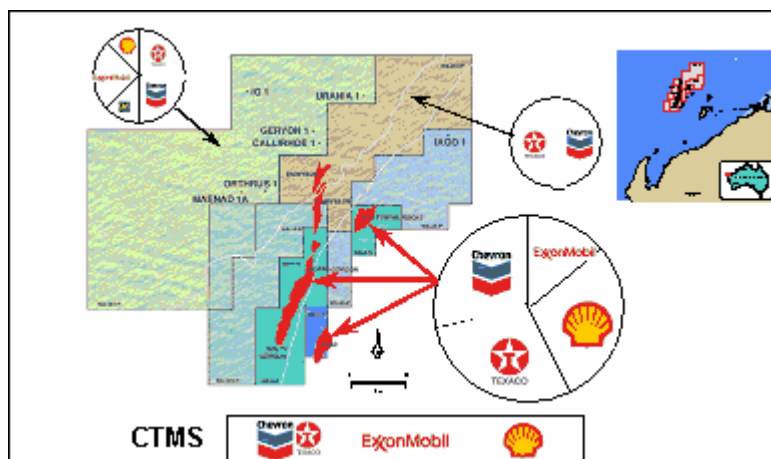


Figure 1. CTMS permit areas

Gas for the State

The development of Gorgon can deliver additional gas to Western Australia's existing gas distribution system and encourage the extension of the pipeline network. A second major gas supplier in the North West will have the dual impact of greatly expanding the market and increasing gas competition,

thereby encouraging investment in Australian-based developments. This new supply of competitive gas will create opportunities for clean energy infrastructure and for new and existing industries wherever gas is delivered within the State.

Gorgon will be an "enabler" for a range of industries relying on the availability of abundant supplies of gas on world competitive terms. The benefits will flow to traditional industries such as minerals processing, the new gas-based sunrise industries and to a wide range of smaller players attracted by opportunities flowing from the expanding industrial base.

The Gorgon Development will build on the skill base already established as a result of Australia's progressive oil and gas engineering, production and exploration industry.

GORGON AREA RESERVES

The Greater Gorgon Area off the north west coast of Australia is a tremendous gas resource base. Estimated gas reserves, including the recent deepwater exploration drilling successes over the last three years, have increased to well in excess of 40 Tcf.

The Gorgon Development is based on extensive proven gas reserves of 13.8 Tcf in the Gorgon gas field situated approximately 130 kms offshore Western Australia at a water depth of slightly over 200 metres. (see Figure 1) The nearest major centre is the coastal town of Karratha. Nearby on the Burrup Peninsula is the North West Shelf Venture's LNG Plant, the heart of Australia's largest resource project to date, which has been exporting LNG for over 10 years.

The Gorgon gas field includes the Gorgon, Chrysaor, Dionysus, West Tryal Rocks and Spar fields. The Gorgon and Chrysaor/Dionysus fields extend for a distance of nearly 70 kilometres. There is potential to further increase the gas reserves available to the Gorgon Development with the discoveries made in the deepwater exploration permit areas shared by the three Gorgon participants and BP Developments Australia Pty Ltd.

GEOLOGY

The ten wells drilled in the Gorgon field and full 3D seismic coverage have enabled completion of a full-field 3D Simulation Model. This high-quality data has delivered a very detailed understanding of the geology and characteristics of the Gorgon reservoir.

The Gorgon structure is a fault bounded Triassic horst block some 45 kms long that ranges in width from 5 kms in the south to 10 kms in the north, where subsidiary shoulder blocks form the bounding structural elements. The top is defined by the Intra Jurassic Unconformity (IJU), a relatively flat surface over the horst which has steep fault escarpments to the east and smaller fault escarpments to the west. The Triassic beds within the horst dip to the

northwest along the southern and central areas and plunge to the north in the northern areas.

The major bounding faults, which have throws of several kilometres, provide closure to the gas charged Mungaroo sand which are juxtaposed across the faults with Barrow Group shales above the IJU, and the Early Jurassic Murat and Athol Siltstone below the IJU. The northern end of the closure is defined by the north plunge of the Triassic and the sealing Jurassic claystone and Brigadier Formation, which are preserved below the IJU at the northern end of the structure. Floodplain shales of the fluvial Mungaroo Formation also act as inter-formational seals, resulting in vertical compartmentalisation of the reservoirs and multiple gas-water contacts.

The Triassic Mungaroo Formation contains good to excellent quality gas reservoirs whose grain size ranges from fine to coarse-grained quartz sandstones with varying amounts of kaolinite. Average porosity is approximately 16% and associated average permeability is 700md (range 1-2000md). Water saturation is generally low, averaging 24%.

RESERVES CERTIFICATION

Independent reserves certification is traditionally a requirement of LNG Sales and Purchase agreements to provide comfort and security to the purchaser of the reserves. This process was completed for the Gorgon Development in 1998 as part of the Gorgon Development Plan. The independent certification was carried out by Netherland, Sewell & Associates, Inc (NSAI), a firm of international petroleum consultants based in Dallas, Texas in the United States.

Total certified proven reserves for the Gorgon Area fields currently stand at 13.8 Tcf, with certified proved plus probable reserves at 17.6 Tcf and certified proved plus probable plus possible reserves at 21.5 Tcf. (see Figure 2)

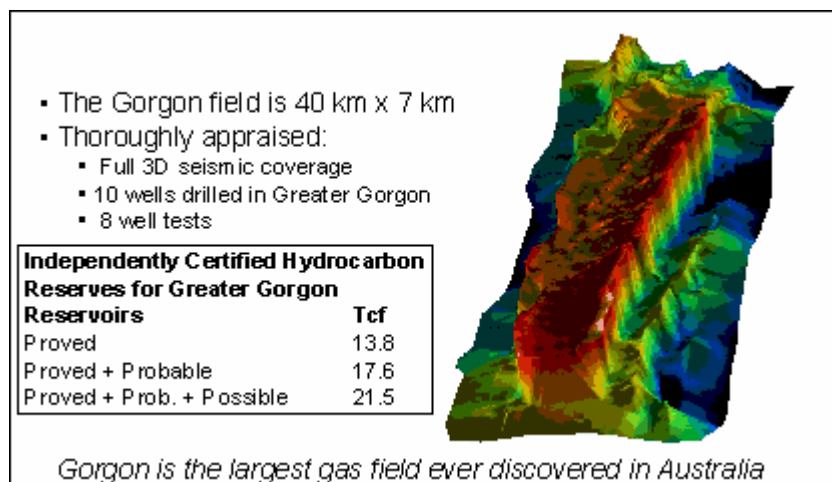


Figure 2. Large certified reserves

GORGON FIELD DEVELOPMENT PLAN

The use of a subsea gas gathering concept is a key feature of the Gorgon field development plan, along with a 70 km tie-back to land-based gas receiving facilities on Barrow Island. (see Figure 3) The plan has been continuously refined and optimised in recent years to improve the Development's cost structure, enabling it to deliver both domestic gas supply and LNG at a competitive unit cost.

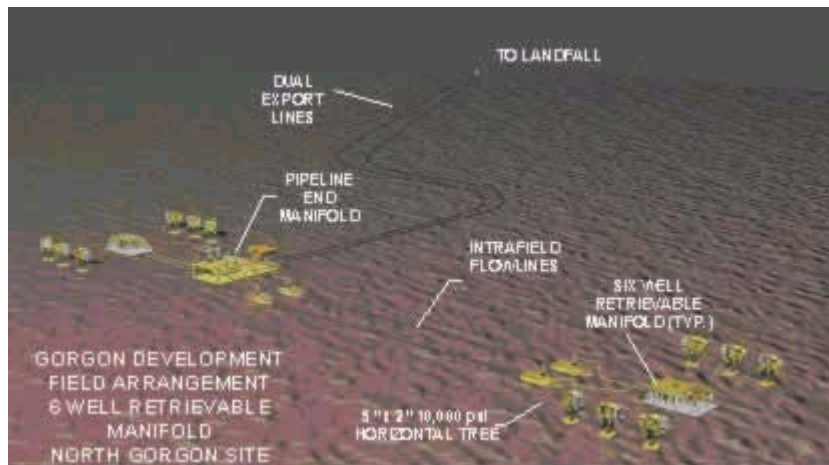


Figure 3. Subsea facilities

ALL SUBSEA DEVELOPMENT BENEFITS

The use of this all subsea solution has a number of benefits:

- It is more cost effective, investing in facilities only as they are needed and not before. It avoids the large up front pre-investment in a platform along with its attendant problems in fixing it to the seafloor and considerable operating cost.
- It presents less safety risk, with no personnel working offshore except during well maintenance from a Diver Support Vessel and no regular helicopter transport of personnel or concerns over cyclones.
- It is more reliable, not being subject to nuisance shutdowns that can occur with the myriad of safety systems necessary on manned platforms.

However, this will be the first ever application of an all subsea system to feed an LNG Train. It will require a high quality approach to procurement and engineering to ensure the installed system works effectively and reliably throughout the entire project life.

FIELD DEVELOPMENT PLAN DESCRIPTION

The Gorgon field will be developed sequentially, with initial production from a single production centre (fed by up to 9 wells) in the northern part of the field in 220m water depth. A further 4 production centres and associated wells will

be added as customer demand increases and reservoir depletion requires. This enables a fit for purpose approach with minimum pre-investment needed for later growth. Eventually a total of 5 production centres and 27 wells will be constructed to access the Gorgon reservoir completely. (see Figure 4)

The subsea facilities will have a high level of system reliability to meet customer needs and reduce the frequency of expensive subsea maintenance by divers or Remotely Operated Vehicles (ROV).

The gas from each production centre will be collected in a subsea pipeline end manifold and routed to landfall at Barrow Island via a subsea tie-back pipeline. At Barrow Island, the hydrocarbon liquid (condensate) and water phases will be separated from the gas stream in a slugcatcher. The condensate will then be stabilised and shipped, utilising existing oil tanker loading facilities on Barrow Island.

Barrow Island has the unique status of both a state-designated Class "A" nature reserve and an operating oil field for almost 40 years. Chevron was the technical advisor to the previous operator, West Australian Petroleum Pty Ltd (WAPET), whose work on the island is internationally recognised for achieving sustainable development alongside oil production. As Operator, ChevronTexaco's commitment to the environment, and worldwide reputation for leadership in environmental management and safety will be dedicated to ensuring that the conservation values of Barrow Island continue to be preserved and protected.

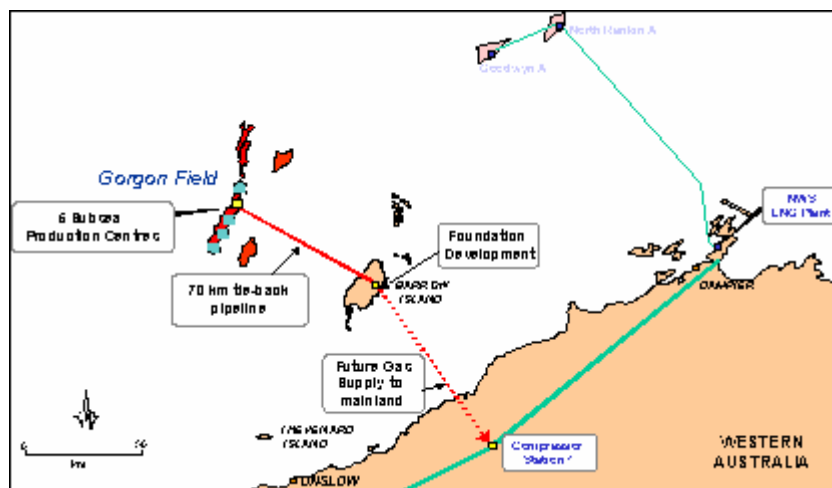


Figure 4. Gorgon field development

GORGON LNG DEVELOPMENT PLAN

Once gas is treated on Barrow Island, it can be delivered to a number of possible outlets:

- an LNG facility on the island, leveraging off the existing oil operation;
- an industrial gas customer on the island; and

- the existing pipeline network servicing Western Australia.

In line with global and national efforts to reduce greenhouse gas emissions, Gorgon is exploring a range of possible Greenhouse Gas mitigation/sink options, including the sequestration of CO₂ for the first time in Australia. Barrow Island appears to offer the best opportunity for re-injection of CO₂ into the deep saline aquifers beneath the island, subject to completing research into its technical and economic feasibility.

LIQUEFACTION TRAIN DESIGN

The current liquefaction train design is based upon the technical expertise of Shell Global Solutions. The development would involve the construction of an air-cooled, electric motor driven, dual mixed refrigerant (DMR) liquefaction cycle LNG train, with a capacity of five million tonnes LNG loaded per annum.

The process is characterised by two separate mixed refrigerant loops. The first loop serves the pre-cooling duty and the second the liquefaction duty. The process design is based on the use of two refrigeration compressor strings, each with a parallel arrangement of compressors driven by electrical motors. (See Figure 5)

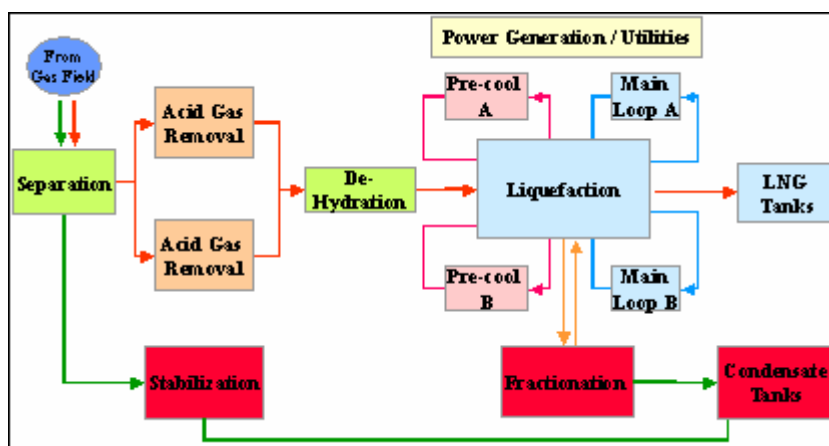


Figure 5. Process diagram

This liquefaction process will be the most efficient yet available, with resultant lowest CO₂ emissions from fuel usage in the industry.

The key components of the LNG Train are:

- CO₂ removal based upon the amine process using activated MDEA (methyl diethyl ethanolamine);
- dehydration using molecular sieve beds;
- mercury removal using guard beds;
- fractionation for heavy hydrocarbon removal and refrigerant production;

- liquefaction trains based upon the DMR process;
- power generation using aero-derivative gas turbines;
- conventional LNG loading facilities; and
- utilities, air-coolers and flare stack.

The plant would be totally self-supporting with respect to its operation, utilities and power generation. Aero-derivative gas turbines would be used to generate the electrical power requirements for the liquefaction train. Waste heat recovery from the GT exhausts would provide the heat input required to regenerate the amine in the CO₂ Removal Unit via a hot water system.

The refrigerant compressors would be driven by electric motors. This improves the inherent safety of the plant by eliminating fired equipment and a high maintenance item from the process area. This also makes the plant design robust and flexible.

LNG storage would consist of two above ground tanks each of 125,000 m³ capacity. LNG would be loaded via a trestle jetty to a loading facility allowing access for LNG carriers in a sheltered location with 15m water depth.



Figure 6. Artist's impression of Gorgon LNG plant on Barrow Island

Condensate produced from the Fractionation Unit would join stabilised condensate from the Onshore Receiving Facilities and then be stored in refurbished tanks for export by the existing Barrow Island export facilities. This means that the only marine activities at the LNG jetty should be the berthing of the LNG carriers themselves.

POTENTIAL IMPROVEMENTS

The LNG train design is already considered competitive with brownfield expansions. Development during the next engineering phases should see opportunities to further improve the solution.

- The liquefaction train design should produce the most compact plant layout to date as the DMR process significantly reduces equipment count. For a comparable capacity the plot area will be 25% of the NWS Burrup site.
- Depending on the distance to the LNG customer it may be possible to reduce the LNG storage to a single 200,000 m³ capacity LNG tank, further reducing the plot area.
- Modular construction methods such as developed for floating LNG and other offshore developments may be applicable and provide cost, schedule and other benefits.

MARKET FOCUS

Gas from the Gorgon Development is being actively marketed to potential industrial gas customers in Western Australia and to LNG customers overseas. The reserves are sufficiently large to support both Western Australian industrial gas markets and LNG export markets over the long-term. Hence, there is potential for an integrated LNG/pipeline gas development.

As all the Gorgon reserves are currently available and uncommitted, the opportunity exists for buyers to obtain foundation development status.

A WORLD-CLASS LNG SUPPLIER

Australia is well positioned to secure a significant share of the growing global LNG trade. Australia offers a stable investment environment, significantly reducing the investment risk for a long-term international LNG export development. In Australia, LNG projects receive strong support from Government at all levels. This could be further improved with government support on issues such as depreciation, PRRT (petroleum resources rent tax) and customs duties.

The North West Shelf, Australia's first LNG supplier, currently supplies 10% of the Asian market, largely through sales to Japan. This trade is valued at A\$1.7 billion annually.

For Gorgon, opportunities for sales are emerging throughout the region, most notably in China, Korea, Japan and the West Coast of the United States.

The current engineering schedule will see Gorgon able to deliver first LNG in 2007. Because of its flexibility, the Gorgon Development can swiftly tailor a single-train LNG facility development to meet the requirements of customers.

This facility can be readily expanded to add a second, third or fourth train for additional production capacity.

This same flexibility means that competitive LNG pricing and supply terms over typical 20-year contract periods can be offered. Gorgon with its vast reserves is in a position to forge new partnerships with customers and capture these opportunities.

NEW GENERATION INDUSTRIES

The establishment of a world-scale GTL industry would give Australia an indigenous replacement for declining oil reserves. Instead of becoming increasingly reliant on imports of OPEC crude and refined oil products, Australia could be both self-sufficient and a significant regional exporter of these clean fuels.

The size of the Gorgon reserves mean it could supply a range of industries that produce ultra clean synthetic middle distillate, DME (dimethyl ether), methanol, and naphtha for transport fuels, power generation and the next generation chemical processes.

There is a worldwide race to attract investment in industries that convert natural gas into high-value commodity liquid fuels. These environmentally friendly products will play an increasing important role in the world fuel mix over the next decade. These products are ideally suited for use in fuel cell technology, predicted to play a major role in the vehicle industry of the future.

SECURE AND RELIABLE GAS

Australia is internationally established as a reliable supplier of gas. This reputation is based on our political and economic stability as a nation and the North West Shelf's 12 year record as an established, secure and reliable exporter of LNG.

This reputation will be enhanced by the addition of another major gas supplier for both the export and domestic markets. Just as the North West Shelf was Australia's entree into the world LNG trade, Gorgon can both add to our LNG capability and also help to establish an Australian gas-to-liquid (GTL) industry, leading the nation's transition to a gas-based economy.

Not only would Gorgon make gas supply from the North West more secure, it would also make Western Australia even more attractive as a location for gas-reliant industries.

IMPACT ON THE ECONOMY

The initial development of Gorgon and an LNG development is expected to attract a total combined initial investment of nearly A\$4 billion. The addition of

a foundation industrial gas customer in Western Australia would create a further A\$2 billion of investment.

During the three year construction period, there would be an average of about 1,700 new jobs created. Once in operation, the workforce would total about 400, of which 50 would be employed in gas production, 150 in the LNG Train and 200 in a foundation customer plant.

The development is expected to provide export income of A\$1500 million per annum from LNG and condensate sales and a further A\$1000 million per annum from clean fuels produced by an industrial gas customer (such as methanol or GTL).

GORGON GAS - FUELLING THE FUTURE

The Gorgon Development is well placed to capture a significant share of the fast growing international market for LNG and natural gas. It will become a major producer of LNG, a clean, efficient energy source for world markets, contributing to the reduction in greenhouse gas emissions globally.

Paper Dated 23 April 2002

Source: Gorgon website (www.gorgon.com.au)



GOLDFIELDS GAS PIPELINE REVOCATION APPLICATION

APPENDIX 7: EXHIBIT MEDIA RELEASES

**Submitted to the
National Competition Council**

March 2003

Government of Western Australia
Media Statement

javascript:openpage('./HTML/lists?opendocument','600',400')

The Hon. Eric Ripper MLA
Deputy Premier; Treasurer; Minister for Energy

javascript:openpage('./HTML/lists?opendocument','600',400)/media/media.nsf

/media/media.nsf

Statement Released: 7-Sep-2001
Portfolio: Energy

StateWest Power to supply Mid-West towns

7/9/01

Energy Minister Eric Ripper today announced an agreement had been signed with StateWest Power Pty Ltd to supply lower cost electricity to Western Power in the Mid-West region.

Mr Ripper said the agreement was worth \$60 million over the 10-year contract period.

He said StateWest Power would build small scale diesel fired power stations supplying Meekatharra, Cue, Yalgoo, Wiluna and Sandstone. Natural gas or LPG would substitute for diesel when economical, generating added environmental benefits.

"StateWest Power will also pursue wind power energy generation to meet some of the energy requirements of these towns," he said.

Mr Ripper said StateWest Power would also supply Mount Magnet through a natural gas fired power station.

He said there were significant savings in contracting an independent power producer to generate power for the Western Power distribution network.

"Western Power currently loses \$3.7 million a year generating and distributing power in this area. Savings of up to \$8 million over 10 years are expected to be achieved by letting this contract, with further cost reductions possible as a result of the use of LPG fuel and wind power."

Mr Ripper said in addition to supplying Western Power with cheaper electricity, StateWest Power would be a competitor for large electricity customers using more than 300,000 kilowatts of power per annum.

He said a steering committee independently chaired by Dr Des Kelly had received 12 expressions of interest in the project and had considered four firm proposals before selecting StateWest Power as preferred electricity supplier.

The proposals were assessed on a value for money basis that included a range of criteria covering community benefit, as well as technical, environmental and commercial issues.

Media contact: Darren Foster - 9222 8788

Government of Western Australia
Media Statement

The screenshot shows a webpage with a blue header and a red body. The header contains the text "The Hon. Eric Ripper MLA" and "Deputy Premier; Treasurer; Minister for Energy". There are several broken image placeholders (red boxes with an 'x') scattered across the page. On the right side, there are several lines of JavaScript code: `javascript:openpage('../HTML/lists?opendocument'...'600',400')`, `javascript:openpage('../HTML/lists?opendocument'...'600',400')/media/media.nsf`, and `/media/media.nsf`.

Statement Released: 11-Jul-2002
Portfolio: Energy

Esperance power station gets green light

11/7/02

Gas from the Pilbara in the north is set to reach the State's far south with the announcement today of the construction of a 330km gas pipeline to fuel a new gas fired power station in Esperance.

Energy Minister Eric Ripper visited Esperance today and signed off on a series of

agreements that will see work start early next year on the construction of the power station in Esperance.

Mr Ripper also gave formal approval for Western Power to enter into an 18-year power purchase agreement with independent power producer, Burns and Roe Worley Developments (BRWD). An agreement promoting investment in a new wind farm was also signed.

The Minister said the power station - expected to be operational by 2004 - would supply more than a quarter of Western Power's regional customers outside the south-west power grid and open up local employment and economic development opportunities.

"We expect this project to slash greenhouse gas emissions by up to 30 percent compared with Western Power's existing diesel power station," he said.

"This is a cost-effective and environmentally friendly solution to Esperance's future power needs.

"In introducing a gas pipeline to the region, there will be other opportunities to replace diesel generation with gas fired generation."

The Esperance Power Purchase Agreement also allows for Western Power to purchase a portion of its energy from alternative sources. This includes other renewable energy providers.

Mr Ripper said the approval of this project meant jobs, training and economic growth for Esperance and surrounding communities.

"Up to 40 jobs will be created during the construction phase of this project," he said.

"We have a strong commitment from Burns and Roe Worley Developments Pty Ltd to employ local people and local businesses and to source materials and equipment from Western Australian businesses where possible."

Mr Ripper said the 330km privately financed pipeline would be built to transport Carnarvon Basin gas via the existing Kambalda terminus to the power station site in the Esperance Port Authority precinct, bringing the total length of the pipeline to 1754kms.

The power station would supply Western Power's 6,327 business and residential customers in and around Esperance - stretching west to Munglinup, east to beyond Condingup and north to Salmon Gums.

The Minister said BRWD would supply electricity to Western Power at a lower generation cost and at higher environmental standards than existing diesel generators.

"There will be no change to the tariff for customers," he said.

"They already receive subsidised power through the uniform tariff scheme, but the cost to Western Power of providing electricity will be substantially reduced.

"This is important economic infrastructure which will put Esperance and the wider region in a strong position to capitalise on other development proposals in the future."

A related agreement allows for BRWD to purchase wind energy to complement the gas generation. This will promote investment in the Nine Mile wind farm, a second wind farm to be built and owned by Western Power.

Mr Ripper said the State Government had negotiated with BRWD to deliver a range of community benefits.

These included:

- investigating the feasibility of providing gas to other consumers on the pipeline route;
- agreement from BRWD to provide heating for the swimming pools and showers at the Bay of Isles Leisure Centre at no cost to the Shire of Esperance. This was to replace an existing arrangement between the Shire and Western Power; and
- a proposal from the company to buy renewable energy from other sources if economical or to develop its own renewable energy initiatives.

BRWD planned to undertake a study with Shark Lake Meatworks into the potential for a plant to produce synthetic biodiesel fuel from tallow, a by-product of the meatworks. If viable, the plant would produce 1.5million litres of fuel a year.

It is expected the study would be completed by the end of the year.

Mr Ripper said a key part of the agreement aimed to maximise local content and employment and training in the construction and operation of the plant.

This included ensuring minor maintenance was undertaken by local tradesman and training of local staff in the operation of the power station.

The company was also required to spend at least \$17.5million of its capital budget on goods and services sourced within Western Australia.

Minister's office: 9222 8788