OffGAR DBNGP DRAFT DECISION

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

PROPOSED ACCESS ARRANGEMENT

UNDER THE NATIONAL ACCESS CODE

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INTRODUCTION

The WA Regulator (Office of Gas Access Regulation – OffGAR) released on 21 June 2001 his draft Decision on Epic Energy's Access Arrangement proposal for the DBNGP under the National Third Party Access Code for Natural Gas Pipeline Systems (NTPAC). He proposes a Reference Tariff of 78c/GJ for transport of gas to Perth (Zone 9) and 85c/GJ to Kwinana industry (Zone 10) in response to Epic Energy's proposed $1.00 and $1.08/GJ respectively. Epic Energy and others are challenging the Regulator's draft Decision. The main areas of dispute arise from the initial capital valuation to be placed on the pipeline, the method chosen for assessing depreciation, its economic life and Epic Energy's 'economic depreciation' proposal. It is widely recognised that Epic Energy paid some $800 million more for the pipeline than was expected, anticipating early expansion of capacity to serve Kingstream's Geraldton steel mill and other developments, most of which have not come to pass.

There are numerous other conditions in the Regulator's draft Decision, but the draft Reference Tariff is by far the most contentious to all interested parties. This submission will concentrate on the Tariff and make limited comment on the other issues which are mostly 'fine tuning'. The pipeline's capacity is fully contracted and now operates close to its capacity at some 200,000 TJ/year, or 5.1 bcm/year. ALCOA is contracted for 40% of the capacity, Western Power and Alinta Gas for 50%.

BACKGROUND

1998-2001 period

Epic Energy purchased the DBNGP from the WA government in March 1998 for $2,407 million. The Transport Tariff to Perth at the time was $1.27/GJ (Zone 9) and has been progressively reduced to $1.00/GJ in 2001. How could Epic Energy make these reductions when they paid such a high price for the pipeline? The company has spent $125 million since 1998 duplicating part of the pipeline south of Perth, mainly to supply the Worsley Alumina Refinery which has undergone capacity expansion from 1.8 to 3.1 million tonnes per annum. The expansion was commissioned in 2000. The annual fixed capital costs of the pipeline are now spread over a higher gas volume and that may be the main reason for the reduced tariffs. Changed depreciation practices by Epic Energy compared to those of the previous owner, Alinta Gas, could be another reason. Only detailed audits of accounts could verify this. The significance of depreciation practices are discussed further below. It is unlikely that Epic Energy could reduce operating and maintenance costs to support the 20% reduction in gas transport charges to Perth.

The Regulator's Draft Decision

According to Epic Energy, the Regulator's draft Reference Tariff comprises around a 90:10 split between capacity charges that have to be paid regardless of the quantity of gas transported (ie fixed costs mainly connected with capital charges and maintenance) and commodity charges that relate to the quantity of gas transported, mainly 7c/GJ in Zone 9 for compressor fuel charges. Data in the

Regulator’s draft Reference Tariff document of June 2001 (pp. 35.36) show that capital charges comprise around 80% of the Reference Tariff.

At the OffGAR Briefing on 2 August Dr Ray Challen, Senior Economist, Environmental Resources Management Australia and speaking for OffGAR, said four options were considered for assessing depreciation and annual capital charges against the pipeline when determining the Reference Tariff. These were:

Depreciated Accumulated Cost (DAC)	$874m.
Depreciated Optimised Replacement Cost (DORC)	$1230m.
Imputed Asset Rate for the Reference Tariff (IARRT)	$1650m.
Epic Energy’s purchase price	$2570m.

OffGAR used DORC with an interest rate of 7.85% for straight line depreciation over their estimated 70 year economic life for the pipeline and 30 years for compressors. Epic Energy used a 100 year life for the pipeline and 57 years for compressors – the latter does appear unrealistic for machinery (Epic Energy 2001). The issue of pipeline life will be discussed later in the context of the likely life of the gas fields.

DAC calculates depreciation on an historical cost basis, including capital investment subsequent to the initial construction of the pipeline. DORC is based on depreciated replacement at current costs and uses a straight line depreciation method. Epic Energy’s David Williams said at the Briefing that the company used a method in its proposal to the Regulator that biased the provision for depreciation towards the latter years of the pipeline’s life based on the purchase price. Dr Challen said OffGAR had no objection in-principle to Epic Energy’s approach.

These various approaches to depreciation provision and others are conditionally permissible under the NTPAC and are embodied in State and Federal legislation within the framework of Competition Policy (GPA Act 1998, pp 204-227). There is provision in the legislation for new customers to contribute to the capital cost of pipeline expansions and/or pay a higher transport charge for their gas than existing customers in these circumstances. NTPAC says the Reference Tariff should provide *‘the Service Provider with the opportunity to a stream of revenue that recovers the costs of delivering the Reference Service over the expected life of the assets used in delivering that Service, to replicate the outcome of a competitive market, and to be efficient in level and structure.’* It goes on to say that *‘the time-path for Reference Tariffs that is implied by the Depreciation Schedule be consistent with efficient market growth, and in particular, to avoid Reference Tariffs that are excessively high in early years and low in later years’”* and *‘depreciation should be over the economic life of the assets…’* (GPA Act 1988, pp 204-208).

Epic Energy’s Ian MacGillivray (2001) says the Regulator’s draft Reference Tariff will have adverse impacts if adopted, and would include:

- Expansion of pipeline capacity would be highly unlikely at the proposed rates.
- New customers would be required to advance the pipeline expansion capital or pay more than existing customers, eg a 280 MW combined cycle gas turbine at 50 TJ/day would require a gas transport price of up to $1.32/GJ. (Note: Western Power proposes 360 MW of gas turbine capacity at the Kwinana Power station by 2005/6.)
- Creating a barrier to competition and abandoning a level playing field for new entrants to compete in areas such as power generation.
- Creating second class citizens on the pipeline.
- Regional impact – lack of development, employment and economic growth.
- New gas producers may be unable to offer discount prices to enable their projects to proceed.
- Putting at risk the sovereign risk/reputation of the State as a place to invest.
- Creation of severe financial distress to Epic Energy.

- Epic Energy's ability to ensure the reliable and efficient operation of the pipeline could be compromised.

DISCUSSION

The pricing problems Epic Energy faces have two sources: The high price Epic Energy paid for the pipeline *and* the wide discretion available in the legislation and standard accounting practice to application of depreciation and annual capital charges to tariffs over the economic life of the asset.

The "market price" and economic rationalism

On the first point the issues are who should bear the burden of Epic Energy's high purchase price for the pipeline and what are the consequences. Obviously Epic Energy must take considerable responsibility for the risk it took in paying such a high price, but its proposal says existing and future customers should do so in the form of a higher reference tariff. By contrast the Regulator's proposal implies new customers should bear the burden, at least in the early years after capacity expansion, with the possibility that subsequent reviews of the Reference Tariff could change the situation. There can be genuinely different views here on what constitutes a 'level playing field', and for whom it is 'level'. Either way customers pay for Epic Energy's high purchase price, but what basis is fair, who pays and when?

Investment in new capacity has a 'lumpy character' and generally occurs in multi-million tranches. For this reason it can be prudent when adding new capacity to increase it by more than the committed new market that has led to the expansion, an argument with some justification. However, the issue of the longer term availability of natural gas and the priorities for its future use are an issue here, discussed further below.

Epic Energy wants to offset its high purchase price for the pipeline through a provision for 'economic depreciation' on a basis that increases the provision annually and to be funded by its proposed higher Reference Tariff, but has not explicitly said so. In effect buyers of pipeline capacity would be paying over an unspecified number of years for the State's $800 million windfall on sale of the pipeline in 1998. Any decision on this point by the Regulator has de facto implications over a wide range of issues that rightly belong in the political sphere as was obvious at the Briefing. The Regulator has been put in an invidious position.

On the second point we need to first discuss some aspects of neo-classical economic theory, otherwise known as economic rationalism. In it simplest terms the theory says that the market will have a rational and efficient outcome when marginal supply costs reach equilibrium with marginal prices (the price at which consumers will forgo consumption in preference for alternative commodities), a price where the rate of return on investment in the assets equals the current interest rate on invested funds generally. It is assumed markets always tend to equilibrium. One must remember that "efficient market" has this specific meaning in economic theory. Alternative energy commodities in this context would be coal, oil and renewable energy.

There are other assumptions behind this proposition that have to be met for a rational outcome as well. For example, all buyers and sellers must have complete knowledge of all information needed to make rational decisions, past, present and future. In addition buyers and sellers must have no difficulty in changing to alternative commodities. Also there is an absence of "price-makers" in the market, dominant players with price leverage opportunities. Given that these conditions are met the theory says markets where "self-interested rate of return maximisers" operate (at the micro-economic level) will also automatically achieve the most rational and productive outcome at the macro level. This over-simplifies the essence of economic rationalism in this gas pipeline context, but is sufficient background for the arguments advanced below. One corollary implied by the last proposition is that the 'market knows best'; that governments should stand aside and be minimally involved.

What equilibrium transport price?

The Regulator has the legal responsibility to determine "the market equilibrium price" for gas transport, in this case where there is a single pipeline owned by Epic Energy, a monopoly supplier. But this price is dominated by the provision for annual capital charges (around 80% of the price) where there are many quite legitimate ways of determining these and permitted by the legislation and accepted as standard accounting practice, as discussed above. This requires estimating the economic life of the asset and who knows what that will be? A wide range of annual charges can be chosen leading to a wide range of possible annual capital charges. Which is correct? Which price is the 'market equilibrium price'? One must conclude that whatever price the Regulator finally authorises will bear little relation to the productivity of the asset over the long term.

It is not surprising that the Briefing on 2 August led to a full debate on the assumptions, values, economic, social and environmental issues embodied in the Regulator's draft Transport Tariff proposal. *This debate also rightly belongs in the political sphere and embraces issues wider than the rate of return on investment* But there could be more serious implications. Epic Energy claims the Regulator's draft Reference Tariff compromises the financial viability of the company and could threaten its capacity to properly maintain the pipeline assets.

The argument above is the bare essence of that in Christopher Sheil's book *Water's Fall: Running the risks with economic rationalism* (Sheil 2000). The water utility industry is another capital intensive industry that has many assets with lives exceeding one hundred years. The same disconnect between the rate of return on assets for an equilibrium price and the productivity of these assets exists, as outlined above for the DBNGP. Sheil argues that the corporatisation/privatisation model of economic rationalism as applied to the water utility industry in Sydney and Adelaide, with its over-riding requirement for the manager to be first of all a "self-interested rate of return maximiser", leads *necessarily* over time to failure of the supply system. He uses as evidence the failure of a privatised sewage works in Adelaide in 1997 that engulfed that city in a "Big Pong" for three months, and the circumstances leading to "boil water" orders in Sydney in 1998 following contamination of the public water supply with the micro-organisms giardia and clostridium. In this context Sheil says that the singular importance of water to everyone means any supply crisis is of immediate political significance. He says governments are placed in a vulnerable position both financially and politically when faced with a 'self-interested manager' able to exploit the situation to maximise his return on assets and which economic theory implies he should do. In the end the management of Sydney Water disintegrated when it was unable to reconcile its central priority to maximise rate of return on assets with its wider public and environmental interest and was replaced by the government in circumstances dramatically described by the subsequent Sydney Water Inquiry. The writer was close to some of the events leading up to this episode during his employment with the then Water Authority of WA.

There are some parallels between these episodes in the water industry and the processes for regulating Epic Energy's gas transport tariffs – note the company's warnings above. But there are also important differences and specific circumstances that need to be taken into account. The specific circumstances of each situation must be taken into account. OffGAR should acquire Sheil's book for background reference. A copy of the Conclusions chapter is included with this submission for your information. Note that a significant natural gas supply failure becomes a major political issue as happened at Longford in Victoria in 1998. We are willing to discuss the subject further with you.

What economic pipeline life?
How much gas does Australia have?

What is the economic life of the DBNGP? The choice of 70 versus 100 years by OffGAR and Epic Energy respectively seems to be based on the likely physical life of a well maintained pipe rather than on the life of the gas fields supplying the pipe. The latter topic does not seem to be addressed at all. Natural gas is a finite non-renewable resource, even though the ultimate extractable quantity is not yet known. The faster it is extracted the shorter the life of the fields and the shorter the lives of gas pipelines. The wording of NTPAC favours growth of gas production and the prevailing political and business ethos favours its rapid development. Economic growth fuelled by natural gas is becoming an obsession an attitude that was clearly expressed at the August Briefing.

The accompanying paper, *A Lot of Gas* by Brian J Fleay (Appendix 1), discusses these issues for Australia in the context of an Australian Gas Association (AGA) report which outlines a 1997 "wish list" of gas consuming and LNG export projects to 2030. The paper compares this projected gas consumption to the Bureau of Resource Sciences (BRS) 1994 high (P5)[1] and low (P95) estimates of ultimate recovery (EUR) of natural gas in Australia. The comparison shows if these growth projects came to fruition that Australian annual gas production would peak at around 85 billion cubic metres (bcm) about 2025, then fall to its present level of 30 bcm by 2050 as the gas fields deplete. Over 80% of Australia's EUR for natural gas is offshore of the Western Australia coast in the Carnarvon, Browse and Bonaparte Basins. A significant portion is well offshore in water 1,000m deep. The DBNGP taps the Carnarvon basin.

A broad-brush look at the Carnarvon Basin for natural gas in the Australian context is warranted. The table below shows cumulative production to 2000, the 1997 median estimate (P50) for known reserves, gas discovered by 1997, my estimate for the yet-to-discover, P50 estimated ultimate recovery, and production in 2000. Exploration in the Carnarvon Basin is approaching maturity whereas the Browse and Bonaparte Basins are at an early stage of exploration and development. Most reserves are found in a few large fields which are usually discovered in the early years of exploration. The data is from Oil and Gas Resources Australia 1999 (Australian Geological Survey Organisation) and Oil and Gas Resources of Australia 1995 (Bureau of Resource Sciences 1996) for P50 estimated ultimate recovery for Australia.

MAJOR AUSTRALIAN NATURAL GAS BASINS

Billion cubic metres (bcm)

	Carnarvon	Browse/Bonaparte	Gippsland/Cent.Aust	TOTAL
Cumulative prodn to 2000	190	-	290	480
P50 Reserves 1997	1250	1140	380	2800
Discovered by 2000	**1440**	**1140**	**670**	**3250**
P50 est. yet-to-discover	150	570	30	750
Est. P50 Ult.Recovery	**1600**	**1700**	**700**	***4000***
Production in 2000	20	Nil	14	34

The Gippsland fields are expected to be in decline by 2010 and a pipeline to the east coast from the north west coast gas fields will be needed well before then on present consumption growth expectations.

There are a number of chemical and minerals processing plants proposed for the Pilbara, which with Woodside's current expansion of LNG export capacity, would consume about 19 bcm of gas per year. Allowing for their progressive establishment over 10 years these would consume about

[1] P5 represents an estimate with a 5% probability of occurring, P50 a 50% probability and P95 a 95% probability.

300 bcm of gas by 2020 and existing uses another 400 bcm for a cumulative total of some 900 bcm by 2020 (WA Oil & Gas Industry 2001, p 10). This is more than half the BRS estimated ultimate recovery from the Carnarvon Basin and by then production decline would be likely or imminent. Additional consumption could be expected from Alinta Gas and electric power generation *via an expanded DBNGP*.. Production could easily decline from some 45 bcm in 2020 to about 10 bcm in 2050. The capacity of the DBNGP is 5+ bcm per year, one quarter of current gas extraction in the Carnarvon Basin.

The electric power industry and some State governments are beginning to recognise some of these realities about natural gas supply, especially in eastern Australia. A leading petroleum journalist, Rick Wilkinson, discusses them in the September issue of Electricity Supply Magazine. He points out that the north western Australian gas fields are some 3,500-3,800 km from the eastern seaboard – delivery costs will be high. While gas turbines can be installed in two years as against 4-5 years for coal at about half the installed cost per MW, the fuel costs for gas will be much higher and the investment in gas provision larger than for coal. Nor does natural gas have the Greenhouse gas and pollutant emission advantages that gas turbine advocates claim. Gas turbines create NOX emission problems in the urban airshed and many gas fields have significant CO_2 in their gas. Gas from some of the Gorgon fields in the Carnarvon Basin contains 12-15% CO_2. Bill Nagle from AGA in the same article takes an optimistic view, but uses misleading statistics saying, " the gas reserves to *current use* ratio is something like 92 years". This implies a rectangular production profile for the full 92 years which is false (ESAA 2001). Oil and gas extraction profiles from petroleum provinces tend to have a bell-shaped profile with the maximum rate being reached in the middle range of extraction followed by a long decline phase.

The DBNGP could be extended some 1,000 km to the Kimberley's to tap the Browse Basin, if that gas has not been committed to the rest of Australia by then. However, the principal gas fields there are some 450 km offshore in water about 1,000m deep in a cyclone prone area. Gas transport charges to Perth could double.

It is now becoming accepted in the petroleum industry that we are approaching the peak of world cheap oil production over the coming decade. Last years rising oil prices signalled the peaking of non-Persian Gulf oil and a shift of focus to the Persian Gulf countries who have nearly 60% of the world's remaining oil, but currently only supply 30% of consumption. The accompanying chart by L.B. Magoon (2001) of the US Geological Survey summarises the situation.

Australia's oil production is expected to decline sharply by 2010 (AGSO 2000, p. 35-39). Bass Strait oil production has declined to only 35% of its 1987 peak. Western Australia is now the country's largest producer but production is expected to decline rapidly by 2010 (WA Oil & Gas Industry 2001, p 5). Our dependence on oil imports will increase rapidly over the next decade when world competition for oil imports from the Persian Gulf countries will become intense. A substantial shift to gas as a transport fuel is likely by 2020, a factor not included in the AGA 1997 gas demand projections discussed above. Currently the consumption of petrol and automotive diesel in Australia approaches that of natural gas on an equivalent energy basis. Transport is likely to become a significant consumer of natural gas.

ALCOA has been mining bauxite in the Darling Range for over 35 years. The Jarrahdale mine has already been closed and the Kwinana alumina refinery is now supplied with bauxite from the Pinjarra mine site. This raises the question of the remaining life of ALCOA's mines and when production will start to decline. It would seem that bauxite west of Albany Highway and north of Serpentine Dam has been mined out and the time must be approaching when the same will happen west of Albany Highway for bauxite within range of Pinjarra. There is a dryland salinity risk to the east of Albany Highway that could pose risks to Perth's water supply if mining proceeded in this sector. When will ALCOA's alumina production begin to decline and how fast? What will be the impact on ALCOA's gas consumption and when will it begin to decline?

If the aspirations of governments and business for gas-based development are achieved then the BRS median estimate of 4,000 bcm for ultimate Australian natural gas production suggests a peaking of gas production in about 25 years, declining significantly by 2050, with a similar profile possible for the Carnarvon Basin. This suggest that the economic life of the existing DBNGP could be less than 70 years and certainly not Epic Energy's 100 years. Any expansion components of the pipeline capacity could be expected to have an even shorter life, less than 50 years, especially if limited to the Carnarvon Basin gas fields.

Furthermore, to distribute annual pipeline capital costs equitably over all gas consumers suggests an annual depreciation provision profile matched to expected pipeline gas flows – highest in total dollar terms in the middle years when gas flows are highest. Several scenarios of possible gas production profiles could be developed to test the sensitivity of annual depreciation and capital charges to such gas production and EUR estimates. Pipeline life should be matched to the best estimates of EUR covering a range of probabilities. The more rapid the development of economic natural gas reserves, the shorter the life of pipelines.

Natural gas will be an important fuel for land transport in the coming decades as the need for oil imports increases, the competition for a shrinking world supply will become intense with accompanying price volatility and supply uncertainty. Is it wise for Australia to expand LNG exports? Is it wise for the electric power industry to indulge in a "dash for gas"? There are no obvious easy alternatives other than natural gas to replace current oil supply as a fuel for transport and mechanised agriculture. The circumstances unfolding around the destruction of the World Trade Center in New York on 11 September add a new dimension to the risks from dependence on oil supplies from the Persian Gulf. These must surely be at risk from the type of attack experienced in New York. All these factors suggest a longer flatter profile for Australian gas production and that limiting LNG exports would be prudent with a corresponding change to the depreciation provision for the pipeline.

Of course the petroleum exploration industry and AGA will challenge the BRS/AGSO estimates for ultimate Australian gas production - and they could be right. It is also true that a very substantial increase in the ultimate recovery is needed to extend significantly the time that high rates of extraction are possible – see the figure in the Appendix. It is significant here that the AGSO is exploring the prospects for oil and gas supply beyond 2020 in locations like the Lord Howe Rise, the Norfolk Ridge and the Tasman Rise, all offshore from eastern Australia as well as the Kerguelen Plateau on the edge of Antarctica. These sites are all over 800 km offshore in water depths of 2000m or more (AGSO 2000). Heroic engineering will be required at high cost and high risk.

CONCLUSIONS

- There are two major problems in establishing a Reference Tariff for the DBNGP. Firstly, Epic Energy's high purchase price for the pipe line. Who should bear the cost of this, how and what are the consequences for future gas development and capacity expansion? Secondly, what is the economic life of the pipeline and how should capital charges be apportioned over this life? Capital charges are the dominant component of the tariff and the pipe line has potentially a long physical life if well maintained.

- The legislation and standard accounting practice permits several options for allocation of capital charges over the economic life of the pipe line all of which can lead to a wide range of tariff options.
- The choice between these options is heavily dependent on value judgements on gas driven development philosophies, priorities, environmental factors and the future availability of gas and alternative fuels. Never forgetting that natural gas is a finite non-renewable resource.
- The debate on what constitutes a “competitive market price” therefore centres around these value judgements the resolution of which rightly belongs in the political sphere. Natural gas is a key fuel the development of which has a large bearing on our future for decades ahead, a time frame that is outside that of normal commercial markets.
- It make sense therefore to base the economic life of the pipe line on the best available estimates of ultimate recovery of natural gas, a non-renewable resource.
- When AGSO’s median estimate for ultimate gas recovery in Australia is coupled with rapid development of natural gas an early peak of natural gas production appears likely suggesting an economic DBNGP life of less than 70 years and even shorter for any duplication, given the generally bell-shaped depletion characteristics of gas extraction.
- However, the debate on a Reference Tariff determination is being conducted without any consideration of the expected life of gas fields or the potential for new discoveries. Development of gas depletion scenarios with associated probabilities is possible and represents a more rational way of estimating pipeline economic life.
- The Electric Supply Association of Australia may be about to review more soberly its present focus on gas for future electricity supply as it starts to assess more realistically the development constraints to gas.
- Provision needs to be made for a rapid development of gas as a transport fuel to replace oil beginning this decade. The aftermath of the suicide attacks that destroyed the World Trade Center in New York raises the priority for this role for gas, given the world’s growing dependence on oil from the Persian Gulf countries.

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APPENDIX 1

A LOT OF GAS

Visions, Fantasies and Reality

By Brian J Fleay

The art of good marketing is never to tell a lie, but never tell all the truth.

BACKGROUND

In May 1997 the Australian Gas Association published its *Gas Supply and Demand Study* projecting high local consumption and export growth to 2030 and requiring a trebling of production. How realistic are these dreams? How does projected production growth match with the best estimates of ultimate Australian gas production?

The projections were based on a "wish list" of gas consuming projects predicated upon high growth in both Asian economies and gas fired electricity generation in Australia. Western Australian projects included expansion of LNG exports, petrochemical and nitrogen fertiliser plants plus four briquetted iron and steel plants, mostly by 2010. Mining developments fuelled by gas were expected to grow.

Eastern Australian gas reserves at January 1998 were 450 billion cubic metres (bcm) with 255 bcm already produced, i.e. 705 bcm discovered. The Australian Bureau of Agricultural and Resource Economics (ABARE) expects another 255 bcm to be produced to 2009/10. Scope for additional discoveries in these states is minimal and a pipeline from Western Australia or Darwin will be needed around 2005 when Bass Strait and Central Australia will be unable to meet demand.

Unfortunately for the gas lobby the Asian Economic Meltdown in 1997 flattened economic growth and energy consumption. Prospects for Kingstream's steel plant at Geraldton seem poor and Woodside's LNG export expansion project has only just commenced. The Gorgon gas project seems even further away. BHP's briquetted iron plant at Port Hedland has been a technical disaster and its future is under a cloud. Gold and nickel mining has slowed and technical problems at new laterite nickel plants are affecting profitability and performance.

However, government and industry hype still conveys a vision of unlimited gas driven growth, even if subdued compared to the pre-Asian meltdown days. What is the real position on Australia’s gas supplies?

Over 80 per cent of Australia’s gas reserves are located off the north west coast of WA, mostly in the offshore Carnarvon Basin, where a new exploration and development phase began in the mid-1990's, and in the offshore Browse and Bonaparte Basins between Australia and Timor. The Carnarvon Basin is reaching a mature development stage, the other two are at an early stage.

The Canberra based Bureau of Resource Sciences (BRS), now part of the Australian Geological Survey Organisation (AGSO), estimated in December 1994 that ultimate recovery (EUR) for Australia’s natural gas would be 3,700 bcm on a conservative 95% probability estimate (P95) and 4,500 bcm on an optimistic 5% probability estimate (P5). By the end of 1997 about 10 per cent (407 bcm) had been produced and 3,200 bcm discovered. There have been subsequent minor additions to reserves, mainly in the Carnarvon and Bonaparte Basins.
Exploration and development slowed in 1998-99 but has since revived with higher oil prices. Investment in the Bonaparte Basin has high risk due to its remoteness and the unstable political environments in Indonesia and East Timor. The petroleum fields there cross national boundaries. In recent months the Bayu/Undan gas field in the Timor Sea has moved closer to development, but has been deferred due to disputes over tax regimes with East Timor. This project was planned to connect with Central Australian gas pipelines supplying the eastern seaboard.

WHAT GOES UP MUST COME DOWN

For any non-renewable resource, like petroleum, production begins from nothing, rises to a peak, or several peaks, then declines and eventually ceases. What goes up must come down. But the development lobby only gives us the upside, avoiding mention of the downside like the plague. The art of good marketing is never to tell a lie, but never tell all the truth.

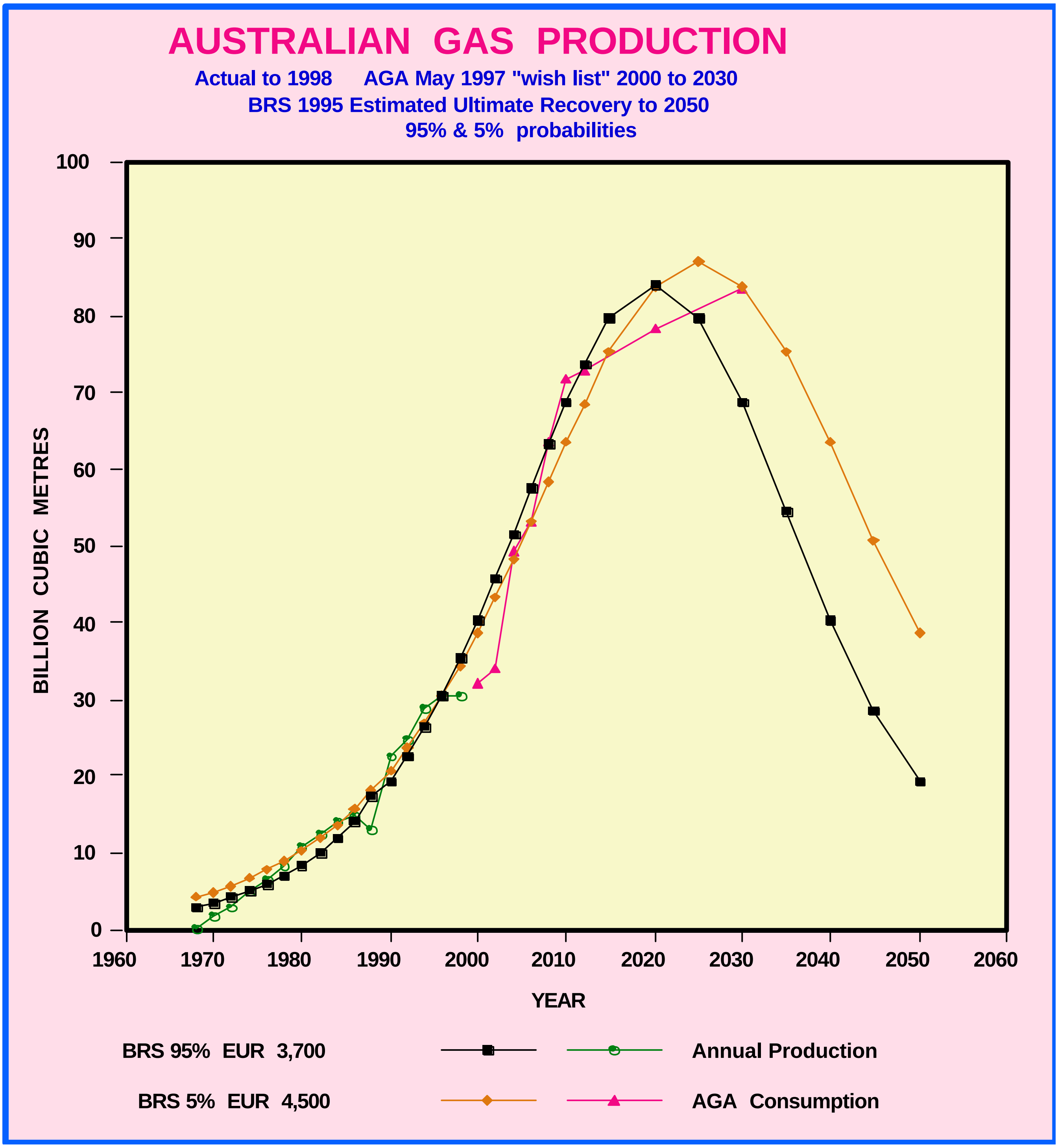
The US petroleum geologist, M.K. Hubbert, pioneered the use of the logistic equation to describe the discovery and production profiles for oil and natural gas in major oil provinces. In 1956 he successfully predicted the time and magnitude of the 1970 peak of US oil production in the lower 48 States. Production and discovery profiles are normally bell-shaped with the peaks occurring near the mid-point of ultimate economic production or discovery. Discovery peaks before production.

The FIGURE below shows AGA's consumption/export projections to 2030 (the "wish list") and compares them to the 1994 BRS P95 and P5 estimates for Australian natural gas EUR by fitting the logistic equation to actual production up to 1998 plus AGA's "wish list" projected to 2020. The peak on both EUR estimates would come around 2025. Statistically, the most likely is near the median (P50) EUR estimate, or around 4,000 bcm. Increasing the EUR by 20% (P95 to P5) does not make much difference to the timing of the peak or its magnitude! In other words AGA's 2030 demand projection could reach a peak before 2030! But their report does not give this down side. On these projections gas production in 2050 would fall to current levels. AGA did not discuss the supply position after 2030, but did include some production of methane from coalfields and imports of gas from Papua/New Guinea. These quantities do not greatly alter these dates. In particular coal field methane is difficult to extract and has a different production profile to natural gas.

The production peak usually occurs before the mid-point for giant oil and gas fields, but comes later for small fields or those offshore. These variations cancel out when the data for all fields is aggregated. Hubbert's concepts are now widely accepted. Jean Laherrere has pioneered the use of the logistic equation to describe multi-peaked production profiles where there are several phases of development, as is the case in Australia.

Of course the 1997 dream is history with projects delayed and timings uncertain. The production profile will certainly be multi-peaked, is unlikely to reach 80 bcm and will be flatter at the maximum. The longer large gas consuming projects are delayed the more likely the profile will assume the character of a "bumpy plateau" at somewhat less than 80 bcm/yr. But whatever production dream is projected it can be interpreted against EUR forecasts using variants of the logistic curve, giving the downside as well as the upside. The other half of the truth.

The realism of the gas lobby's dreams must be questioned from both the demand and supply sides. What are the implications for proposed steel mills, power stations and chemical plants? Are the promoters, financiers and shareholders aware that available gas may decline so soon? Are government agencies, economists and politicians aware? Is the public aware?



Oil based fuels drive the transport system and are an essential input to agriculture, construction and mining. These industry sectors consumed oil equivalent to 30 bcm of gas in 1994/95, about equal to 1998 Australian gas production. Gas is the only fuel that can readily replace diesel using existing engine technology.

Australia has consumed about half of its EUR of conventional crude oil and our self-sufficiency is expected to decline rapidly next decade, according to the Australian Petroleum Producers and Exploration Association (APPEA 2001). Since the mid-1980's over half world oil supply growth has come from Persian Gulf countries turning on wells shut down in the early 1980's, when world consumption fell while production expanded in Alaska and the North Sea. The remainder has come from expensive sources in ever smaller fields outside the Persian Gulf. Low oil prices since 1985 have decimated industry profit margins and eroded the wealth of OPEC oil producers, forcing a downsizing of the oil exploration and development industry. In late 2000 the last of the spare oil production capacity from the 1980's was turned on – only Saudi Arabia has limited spare capacity left. Oil prices have risen two to three fold since early 1999 as the supply focus now shifts to the Persian Gulf.

Clearly gas consumed by transport and agriculture should soon increase rapidly, adding to the pressure on supply. AGA's demand projections made negligible allowance for these sectors.

Enough gas needs to be reserved to support Australian agriculture and transport through to mid-century when both sectors will have to survive without dependence on petroleum based fuels. By then world oil production is likely to be one quarter of present levels and world natural gas well past its peak, both with higher production costs than at present.

NEW FRONTIERS

BRS estimates for the EUR of Australian gas need to be qualified. Some will be very expensive. Scott Reef and Brecknock in the Browse Basin (950 bcm) is 400 km north of Broome in water mostly 1000m deep. Scarborough (230 bcm) on the Exmouth Plateau in the Carnarvon Basin is 270 km north west of Onslow in water 900m deep. The Gorgon-Chryasor group (about 630 bcm) is 150 km north of Onslow in water from 120m to 800m deep. Bayu-Undan (100 bcm) in the Timor Sea is 500 km. from Darwin in moderately deep water. Much of the undiscovered gas is likely to be in such deep water. Some Gorgon-Chryasor gas contains 12-15 per cent carbon dioxide and it is not clear how to dispose of this and at what cost. Its release to the atmosphere would significantly increase Australia's greenhouse gas emissions.

These deep water projects will be expensive to explore, develop and operate even with advances in technology, which is why the APPEA is lobbying for an exemption to wellhead taxes. Drilling costs are $5-8 million in water up to 200m deep, ten times onshore well costs, and $40-50 million in waters 1500m deep. It costs up to ten times as much to transport gas long distances as it does oil.

Campbell (1999) says deep water economics for oil depends on very high flow rates per well and finely tuned operations that have a short life. Operations are risky and prone to massive damage if small things go wrong. These are marginal operations that are even more risky when gas is the main product.

Australian upstream petroleum companies, like their international counterparts, suffered from 1985 to 1999 from poor returns due to rising costs from marginal fields and low oil prices. They are confined to the world's high cost areas with small fields. The Persian Gulf has over one quarter of the world's gas reserves and can produce it at 20% lower cost than in Australia. The focus of oil investment is poised to shift to the Persian Gulf where 60% of the world's remaining oil is located.

The energy cost of extracting gas from these deep water fields will be higher than at existing sites which means a reduced net energy yield, the difference between the energy content of the oil or gas and the direct and indirect energy used to extract it into a useable form. Unit costs on the production downside will increase and the energy cost of extracting the tail end of the gas could exceed the energy content of the gas produced before the EUR is reached. Transporting gas as LNG incurs an estimated 15-30% energy loss (Hanson 1999). Hence export of LNG would lead to a net energy loss from these projects at an even earlier stage of depletion.

Given these scenarios the BRS EUR estimates for gas need qualifying, offsetting more optimistic claims that some say can be expected. That suggests a P5 EUR for cheap gas of around 4,000 bcm and a P95 around 3,500 bcm, implying a most likely (P50) production peak about 2020 based on AGA's 1997 "wish list".

The BRS has made preliminary surveys offshore on the Lord Howe Rise, the Norfolk Ridge, the Tasman Rise, the Kerguelen Plateau and the Townsville Trough east of the Great Barrier Reef. All these sites are in water up to 2,000m deep, are up to 800 km offshore and would be even more expensive to develop if hydrocarbon source rocks are present at all and suitable sealed giant reservoirs exist.

CONCLUSION

Statements on petroleum reserves and likely new discoveries are political statements not to be taken at face value. Remember when production growth is projected there is always a down side. And on the downside net energy shrinks - the useable energy produced, the parameter that matters. Production might still be profitable to the company but not so beneficial to the community. Many questions must be asked to get at the truth behind the statements and determine what has NOT been said. When this is done a more sober appreciation of the future is obtained. This is certainly the case for Australia's gas future.

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