Relevant North American Approaches

UIWG August 1998 Consultation Paper

Prepared for

Allgas Energy Ltd

Prepared by

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Introduction

This report has been prepared by Glen Gill, Managing Director of Brisbane-based Innovative Energy Australia Ltd Pty, at the request of Allgas Energy Ltd. This report describes various approaches from the North American gas industry that are pertinent to the current debate in Australia facilitated by the Upstream Issues Working Group (UIWG). This report was prepared as an attachment to a formal submission prepared by Allgas Energy Ltd.

Innovative Energy has provided consulting services to Woodside Petroleum, Coastal Corporation, Enron Corporation, Lend Lease, INCITEC, and Alberta Energy Company. Glen Gill has thirteen years experience in the gas industry of North America and has held the position of Vice President Gas Supply with Enron Gas Services and Marketing Manager for Alberta Energy Company.

The North American gas market is without a doubt the most sophisticated and efficient gas market world wide. A thorough cost / benefit analysis was performed on the gas industries of Canada and the U.S. by their respective governments revealing better than expected results some ten years after the de-regulation and industry restructuring of the late 1980's. The following are a sample of the impressive statistics associated with the North American gas industry:

- With about 17 percent of the world's potential gas resources, holds only about 6 percent of proved gas reserves

- In 1996 the average net back gas price to the producers plant gate was US$1.81/MMbtu compared to US$1.15/Mmbtu for the rest of the world
- 26 Tcf of gas demand in 1996 compared to 77 Tcf worldwide
- Delivered prices to end users among the lowest in the world; between 1990 and 1995 inflation adjusted natural gas prices declined in all end-use sectors and by more than a third for the electric utility segment
- U.S. gas demand has grown at an average annual rate of 3.1 percent over the period 1986 to 1996
- As of 1995, 384,000 miles of gas pipelines in North America compared to the world total of 780,000 miles
- 45% growth rate projected by 2015[1]

In the gas industry of North America, natural gas is readily sold and purchased throughout the value chain, including in-situ reserves, unprocessed or raw gas, and pipeline spec gas. Although the first two categories of gas are not fungible commodities, they can be readily priced and efficiently transacted. Furthermore, arbitrage within the gas industry and cross energy commodities occurs at a rapid pace. This is, perhaps, the true test of when one has achieved a competitive gas market.

Definition of Upstream Facilities

The definition of upstream facilities currently applied in Australia's gas industry is quite different from that of North America. The definition of the upstream sector in North America is restricted to the exploration, drilling, and production activities. Gas gathering and processing are considered to be midstream activities. Only the large vertically integrated petroleum companies embrace gas gathering and processing as a core activity. The Interstate Natural Gas Association of America describes the US gas industry as follows:

> …for a long time the energy industry has been characterized by its separate functions – large and small producers, midstream

[1] Enron Corporation, *1997 Enron EnergyOutlook*

> gatherers and processors, intrastates, interstates, gas distributors, combined gas and electric companies, municipalities and co-operatives.[2]

Open access to gas gathering and to gas processing has been one of the foundation principles upon which the very competitive upstream sector of the North American gas industry was built. In fact INGAA states that the increasing ownership of offshore pipelines in the Gulf of Mexico is problematic and recommends that the FERC should create more competition "to transport offshore production requiring open access for all OCS transporters."[3] INGAA continues to argue its point with: "producers do not have incentives to attach or transport other producers' gas because third-party gas competes with the producers' own gas. That is not true of pipelines who have an incentive to attach as much supply as possible in order to maximize revenues."[4]

> The 130 pipelines presently on the OCS all perform essentially the same function – gathering gas for delivery onshore to processing plants and interstate pipelines. In spite of their similar business, there is a dual transportation market of regulated and unregulated offshore pipelines. 46% of OCS facilities – existing gathering systems, spindowns and new deep water projects-aren't covered by the Natural Gas Act[5]

An INGAA study had the following findings:

- the natural gas industry's 14,112-mile offshore pipeline network is operated by about 140 companies. Producers own 45 percent of facilities, interstate pipelines own 48 percent and pipeline affiliates own 7 percent.
- Since 1990, the gas industry has spent $3.5 billion installing about 4,000 miles of new pipe; producers own 76 percent of the pipelines built since 1990. They owned only 32 percent before then.
- Gas resource development is driving pipeline development. Some 1,512 miles of new pipe are being planned, costing $1.6 billion. Major oil companies and independent producers would own 70 percent, pipelines 22 percent and pipeline affiliates 8 percent.[6]

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[2] INGAA, http://www.ingaa, *A New Vision For NatAllAural Gas Regulation*, page ii.
[3] INGAA, http://www.ingaa, *A New Vision For Natural Gas Regulation*, page 1.
[4]Ibid, page 24.
[5]ibid, page 20.
[6] INGAA, http://www.ingaa.org/FOUNDATION/Information/1998Press/060398.HTM

Underground Gas Storage

The Public Consultation Paper seems to ignore the impact of the underground gas storage sector generally and regarding acreage management specifically. The storage of natural gas underground in depleted reservoirs, aquifers, and solution mined salt caverns originated in North America in the 1800's and gas storage has and continues to play a major role in bringing efficiency improvements to the gas industry. The assertion in the consultation paper that gas storage is expensive and results in gas losses is misleading.

There is over 3700 Bcf of working gas capacity at 316 locations throughout the U.S. This capacity is composed of depleted reservoirs, aquifer, and salt cavern storage to the extent of 86%, 12%, and 2% respectively.[7] Historically gas storage was developed by pipeline and local distribution companies. Such storage was regulated in much the same manner as pipelines. With deregulation in the 1980s, marketing companies developed non-regulated projects in order to better manage their trading risks. These storage projects were typically downstream in location. Upstream storage and storage at the interconnection points of multiple pipelines (hubs) were more recently developed. Interstate pipeline companies, LDC's and intrastrate pipeline companies, and independent operators operate 62%, 34%, and 4% of the U.S. gas storage respectively.[8]

The more recent storage development projects tend to be high deliverability as opposed to the more traditional seasonal storage.

> New and expanded storage facilities added 1,395 million cubic feet to daily deliverability in 1995, an increase of 2 percent over the 1994 level. High-deliverability salt cavern storage dominated the additional deliverability, accounting for 65 percent of the increase.[9]

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[7] U.S. Office of Oil and Gas of the Energy Information Administration, *The Value of Underground Storage in Today's Natural Gas Industry,*DOE/EIA-0591 (Washington, DC, March 1995), Page 45
[8] ibid, page 45

Due to its inherent security of supply and infrastructure minimisation value, storage developers have preferential rights to petroleum leases. The right to store gas in a horizon is distinct and separate from the right to produce. Legislation regarding the rights and obligations of storage developer / operators abounds in North America and differs dramatically from production licences. The ability to vertically relinquish geological horizons one of many important interfaces with acreage management. Reservoir candidates for gas storage are relatively scarce and therefore it is in the best interest of the public to not let producers sit on such candidates.

Producers prefer to sell plant productive capacity rather than lower cost deliverability associated with underground gas storage and therefore are not the first to develop storage. Rather storage development is a niche role, largely filled today in North America by commercially astute marketing companies. Storage and other such risk management tools have allowed gas trading margins to drop from $0.10/GJ in the 1980s to less than $0.01/GJ in the mid 1990s. Producers, however, tend to benefit from storage, for "increased use of salt storage and new technologies, such as the use of horizontal wells in conventional oil and gas storage reservoirs, enable the industry to bring large amounts of incremental supplies of gas to markets sooner than in the past".[10]

The creation of market centres or hubs have significantly assisted in the elimination of interregional disparities in the gas market of North America.

> At least 39 center are operating in the United States and Canada, providing numerous interconnections and routes to move gas from production areas to markets. … 47 percent of working gas storage capacity in North America is directly or indirectly accessible by market centers.[11]

Storage serves as both a sink for surplus gas production and a source of gas readily available to the market. This dual role performs a unique function in the market. "In

[9] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas 1996: Issues and Trends,* DOE/EIA, page ixi, available from EIA's web site at http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/.html

[10] ibid, *Data Trends: Wellhead and Spot Prices,* page 1

fact, in the view of the many natural gas industry participants and observers, it would be difficult to overstate the importance of storage and information about storage levels and stock builds and drawdowns in influencing prices in both cash and futures markets."[12] Storage is essentially cost effective "line pack". While pipelines can temporarily store gas, their ability to do so pales in comparison to underground storage.

As the Australian gas market matures, the role of underground gas storage will become clear. It is important to set the stage for the development of this integral part of the value chain at this time. Acreage management issues will have to be sorted out well in advance of the need for storage. Although gas storage in North America was once essentially all regulated, most new storage additions over the past decade have been at market based rates. The importance of this sector to an economically efficient gas industry is illustrated by the following:

> Underground storage is a vital part of the natural gas industry. The ability to store gas ensures reliability during periods of heavy demand by supplementing pipeline capacity. Storage also enables greater system efficiency by allowing more level production and transmission flows. End-use customers gain from this increased efficiency with reduced overall costs of service.[13]

Gas Processing

One of the keys to a robust upstream sector in North America is that gas gathering and gas processing are often performed as a service to gas bearing regions by independent third parties. As of 1994, "The largest share-40.3%-of the world's gas-processing capacity continues to reside in the U.S. …Canada maintained its position as the second leading gas processing region with 19.8% of the world's processing capacity"[14]. Of the 19.8 Trillion cubic feet of 1996 U.S. marketed gas production 17.5 Tcf required

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[11] ibid, page x and xi
[12] Energy Information Administration, *Natural Gas Monthly December 1997,* page ix.
[13] Energy Information Administration, *The Value of Underground Storage in today's Natural Gas Industry,* 1995, page vii of the executive summary.
[14] Oil & Gas Journal, *OGJ Special – Worldwide Gas Processing*, June 13, 1994, page 49.

processing[15]. In Canada, all of the gas produced from the province of British Columbia requires gas processing and most of Alberta's gas production, excluding that located in the south east region of the province, requires gas processing. Gas production that is not considered to require processing simply requires dehydration and compression.

The gas processing sector is a large one in North America and the structure of the sector varies considerably from one producing region to another. In British Columbia, the province has elected to essentially prohibit producers from owning gas processing plants. Westcoast Energy provides gas gathering, processing, and pipeline transmission service to 85%+ of the province's 3.2 Bcf/day of raw gas production in 1998 (down from 99% in 1985)[16]. The remainder straddles the Alberta / B.C. border and is processed in Alberta prior to entering the NOVA Gas Transmission system.

Westcoast Energy owns and operates ten large gas processing plants, three sulphur recovery plants, 32 compressors and booster stations, and numerous miles of gas gathering system in B.C. Westcoast Energy's average rate base associated with gas gathering and processing has increased from $C 339 million in 1987 to $C 1.4 billion in 1998. Westcoast Energy provides gas gathering and processing services to 35 producers on a fee for service basis. The fee-for-service rates are regulated by the National Energy Board in much the same way as a pipeline toll. A cost-of-service was applied until 1997 and since then a lighter handed regulatory structure has been in place.

In Alberta, the source of most of Canada's 5.8 trillion cubic feet per year of production, a variety of gas processing models exist. Historically in Alberta, producers built their own gas gathering and processing facilities. More recently, third parties providing gas processing services have entered the industry. The largest gas processing plants in North America are not located on gas fields but at the interconnection of the Alberta export points of the NOVA Gas Transmission system. These plants are mostly owned by

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[15] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Annual 1996,* Page 1.
[16] Canada's Gas Plant Directory – volume IV – 1997-98, Northern Star Publication, Table 1 – *GasProcessinc and NGL Plants and Major Production Facilities in British Columbia* .

TransCanada and, in response to a government initiative to build a petrochemical industry in Alberta, they process every molecule of gas leaving Alberta. Such plants are commonly referred to in Canada as straddle plants.

> TransCanada owns 16 gas processing and related gas gathering facilities in Western Canada, and related gas gathering facilities in Western Canada, a natural gas liquids extraction plant at Cochrane, a 75% interest in the Empress II extraction plant and a 50% interest in Empress V, currently under construction. As well, the company holds a 43.4% interest in the Younger gas processing facility in British Columbia, a 100% interest in the Central Foothills gas gathering system,… TransCanada owns four Louisiana-based gas processing plants with capacity of 2.2 Bcf per day.[17]

TransCanada is a large pipeline company with interest in over 43,000 kilometres of gas pipelines and is also a leading energy trading company in North America. They have no ownership interest in gas reserves and production.

Many of the largest owner / operators of gas gathering and gas processing assets are not participants in the "upstream" sector. The provision of field services is a core competency of large US based companies such as Dynegy (formerly Natural Gas Clearinghouse "NGC") and El Paso. The provision of such services to producers extends back to as early as 1922, when the Warren Petroleum Company was formed.

"NGCs substantial natural gas and natural gas liquids assets, located in the major North American producing basins, provide customers with complete gathering, processing, transmission, fractionation, storage and marketing services"[18].

> NGC's strategy of acquiring processing plants was designed to allow NGC to offer producers an added value beyond the price of their gas. In this case, it is natural gas liquids. 'Our goal here was not to be just a processor, but to gain an advantage that would persuade a producer to commit supply to us' … The pipelines and processing plants that NGC has acquired averaged 62 percent utilization when purchased, while the rate now stands at more than 90 percent.[19]

[17] TransCanada, information available at their web site: http://www.transcanada.com/business/fbus_gp.htm
[18] NGC Corporation, *1997Annual Report,* page vi
[19] Natural Gas Clearinghouse, *A Decade of Excellence in Energy 1984 to 1994,* brochure.

NGC, now Dynegy, have no ownership in gas production, yet own and operate the following assets:

- 4.5 billion cubic feet of natural gas processing per day
- Processes 3.24 Bcf/d of gas on average
- 56 gas processing plants
- Approximately 17,000 miles of natural gas gathering and transmission pipelines
- Fractionation capacity of 240,000 barrels per day
- Owns, manages or controls 70 Bcf of natural gas storage capacity
- Works with over 650 gas suppliers[20]

Dynegy, in its field services role, "aggregates volumes from multiple producing wells into quantities that can be economically processed to extract natural gas liquids and to remove water vapor, solids and other contaminants."[21]

A second major provider of field services to U.S. producers is El Paso Energy Corporation.

> El Paso Field Services owns a wide array of gathering, processing and treating assets and offers global compression services and sophisticated gas flow management to producers throughout the southern United States and Gulf of Mexico. El Paso Field Services maintains over $1 billion in assets, with approximately 10,260 miles of gathering and intrastate pipeline and interests in 25 processing and treating plants and eight offshore platforms.[22]

Refer to the attached information regarding specific ventures.

Marketing of Jointly Produced Gas

Throughout North America gas exploration and production activity is conducted in joint ventures. Joint ventures are a normal risk management vehicle due to the fact that E&P

[20] Natural Gas Clearinghouse, *The Energy Store,* 1996 brochure and data available on the web site at http://www.ngccorp.com/website.nsf/all/Pipelines+and +Gas+Gathering+Systems.

[21] ibid

activities are inherently of high risk. Farm outs/ins and the unitisation of production further complicates the ownership structure. Like Australia, North American producers prior to industry deregulation were poor at gas marketing.

> Before deregulation, gas marketing was part of the business that was largely ignored by producers. If the producer discovered gas, it arranged a long term reserve contract with the local pipeline company and produced gas over an extended period, receiving the regulated price. After deregulation, marketing became a major focus of the business. With the low end of the gas price scale sometimes being one-half of the high end (ie. Spot prices at $0.90 in 1992, while long term prices for cogeneration projects often exceeding $2.00), producers who were successful at marketing gas were much more profitable than those who were not. Producers found that success came through mixing and matching contract terms with available supply, and selling directly to LDCs and end users rather than to the traditional pipeline company.[23]

The most successful gas producers at marketing were the small to mid size ones due to their agility and their attitude of embracing change. The integrated companies and major producers such as Texaco, Shell, Amoco, Exxon, Mobil and Chevron resisted change, and soon lost market share. The once small producers grew at a tremendous rate. In fact most of the top drilling operators in Canada over the past decade did not exist prior to deregulation, and most are gas focussed. Renaissance is one such company.

Prior to deregulation of Canada's gas industry, gas production was marketed jointly by the operator of the field. Upon the introduction of an open market, producers of all sizes, and in fact governments began taking their gas in kind and marketing separately. The benefits of a successful marketing outcome far outweighed the issues of balancing production from a co-owned well.

> When gas marketing becomes deregulated and each producer of a co-owned gas reservoir becomes responsible for marketing its own share of gas production, disagreements often arise between co-owners regarding the appropriate methods of sharing revenues from co-owned production where one co-owner fails to take its share of production in kind. These

[22] El Paso Energy Corporation, information available at their web site: http://www.epenergy.com/about/profile.htm

[23] Macleod Dixon Barristers & Solicitors, *Summary of Canada's Gas Deregulation*, unpublished report, 1994, page 4.

issues are often dealt with inadequately in the co-ownership agreement that the parties entered into when they became co-owners. The disputes are often settled through one of the following types of agreements:

- Ownership and disposition of production agreement
- Gas balancing agreement
- Gas banking agreement
- Revenue sharing agreement[24]

To not take ones gas in kind regardless of the ownership percentage or gas production rate became the exception. The Alberta Energy Company was one of the most successful gas marketing companies in Canada according to a bench marking study conducted by Calgary based consultants, Ziff Energy. Upon deregulation, the Alberta Energy Company took all of its share of daily gas production from hundreds of non-operated wells and pooled such gas to its own markets. This was done without any disputes and any of the aforementioned agreements. Alberta Energy Company created the major gas trading hub in the WCSB, the AECO hub, where it developed underground gas storage and a place to aggregate and match gas production with sales. It also offered such services to other producers.

Market Power

"Over the years, economists have come up with three general ways to evaluate market power: ease of entry into the market; market concentration, sometimes using the Herfindahl-Hirshman Index (HHI); and market performance."[25] Regarding ease of entry, the FERC's policy is that "a company with a large market share may not be able to exert market power if entry into the market is easy or there are other competitive forces at work"[26]. The barriers to entry for new production entrants in Australia is high; the long term contracts with almost all of the market is but one of many barriers.

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[24] Ibid, page 8.
[25] INGAA, http://www.ingaa, *A New Vision For Natural Gas Regulation*, page 4.
[26] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, etc., 74 FERC 61,076,61,234 clarified, 74 FERC 61,194, reh'g denied, clarified, 75 FERC 61,024 (1996), pet. For review pending sub. Nom. Meridian Oil Inc v. FERC, D.C. Cir. Nos 96-1160, et al. (filed May 14, 1996).

Regarding market concentration, "the theory is that the larger the number of sellers in a market, and the smaller the market share, the less likely it is that any player or group of players can dominate the market and set prices"[27]. The concentration of market share in the upstream sector of Australia's eastern seaboard should be an area of great concern. An area of growing concern in North America is the offshore Gulf of Mexico.

> While the Gulf of Mexico production and leaseholds are not overly concentrated, market shares for the 10 largest OCS producers exceed the U.S. average. The 10 largest companies produce 52% of the total offshore production. (For the total U.S. (onshore and offshore) the market share of the 10 largest producers is about 31%.) Producers own all the leases, control all the production and own 50% of the transmission. This represents a significant amount of bargaining power.[28]

The third factor commonly examined is market performance. The case made by producers in Australia is that all is well given the low well head prices as bench marked to the U.S. This argument is diffused in the section on well head price comparisons. The gas industry of Australia is very inefficient – hence the need for national gas reform. The upstream sector is no less inefficient than the other sectors, and perhaps even more so. Australia has a world class resource base that is not yet reflected in gas prices. Additional comments relating to the characteristics of a performing gas market are contained in the section titled "Gas Contracting Practices".

Wellhead Price Comparison

Producers and APPEA have recently stated that the existing marketing arrangements and level of upstream competition must be okay, given the relationship of well head prices in Australia to the US. While this argument ignores the major differences in the market structure between the US and Australia, the same producers caution that international

[27] INGAA, http://www.ingaa, *A New Vision For Natural Gas Regulation*, page 7.
[28] INGAA, http://www.ingaa, *A New Vision For Natural Gas Regulation*, page 23.

approaches regarding acreage management, joint marketing, access to processing facilities, etc are not particularly relevant, given the differences in size and structure to those in Australia. In my view, the differences in size and structure caution so often referred to in the Consultation Paper detracts from the fundamental principles in play. There is a variety of regional gas markets in North America; not one homogeneous market as implied in the paper. For example the petrochemical dominated markets of Texas, Alberta, and Louisiana are vastly different from the mid west and north east U.S. markets. Furthermore the "rust belt" of the mid west is vastly different from that of the north east.

Regulated prices disappeared in both Canada and the US in the 1980's and since that time, the market has determined gas prices. Producers, in any given basin, simply receive the net back price as calculated on any given hour, day, or month after the deduction of freight (transportation) costs. As the market has matured, even the cost of freight is beginning to be set by the market value or price basis between any two regions of the continent. Any comparison of well head prices between Australia and North America has, in my view, minimal value. The fundamental pricing structures are radically different. As the Interstate Natural Gas Association of America explains,

> the reason the market is so competitive is that all the participants, from commodity producer to the last service provider, are price takers from consumers. Consumers will undoubtedly be better off. They will have more choices of services, more conveniently provided, and because of competition those services will be less expensive.[29]

Australian producers are price setters while those of North America are price takers. More important than well head prices is the delivered price to end users, especially those using gas as a feed stock, and faced with global competition for their products.

If we must compare well head prices, then we should not do so in an ad hoc manner. Unlike Australia, well head gas prices in North America vary considerably over the year

[29] INGAA, http://www.ingaa, *A New Vision For Natural Gas Regulation*, page iii.

and from one year to the next (refer to attached table 1.0 and 2.0). The 1995 price of $US 1.55 per Mcf was the lowest annual average (in constant dollars) since 1976[30]. "The average natural gas wellhead price from 1993 through 1995 was $1.86 per thousand cubic feet (1995 dollars), which is 46 percent less than in 1985.[31] Prior to the deregulation of electricity, natural gas was by far the most volatile commodity in North America. It is not uncommon for the four hour Alberta spot market to experience swings in excess of $4.00/GJ. Furthermore, unlike Australia, well head prices of gas vary significantly from one basin or region to another. While the US average well head price in 1996 was $US 2.17 per thousand cubic feet, prices by state varied from a high of 2.62 for Alabama to a low of 1.37 for Colorado[32]. There has been for some time a large difference in the average annual well head gas price of Canadian gas compared to U.S. production; the Alberta Gas Reference price averaged $C 1.95/GJ in 1997[33] (refer to attached figures). "The average wellhead price in Alberta was roughly 66 percent of the average wellhead price in the lower 48 States for the 1990 to 1994 period."[34] Given the exchange rate at this time, Australian well head prices have lately been lower than those of the U.S. but much higher than those of Canada.

Unlike Australia, well head gas prices in North America reflect market conditions. Prices are very volatile, reflecting the rapidly changing supply / demand balance driven by weather variations, storage fill/depletion patterns, and interregional pipeline capacity constraints. Recently, financial institutions speculating on future gas prices have influenced pricing patterns more than the physical world. Among other things, year to year price changes reflect the amount of pipeline capacity connected to any given basin, the degree to which it is depreciated, and its utilisation rate. U.S. well head prices have been significantly higher than those of Canada for the past decade; reflecting the growing

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[30] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Annual 1996,* Page 7
[31] ibid, page 89.
[32] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Annual 1996,* Page 16, available at EIA's web site at http://www.eia.doe.gov/oil_gas/natural.
[33] Canadian Association of Petroleum Producers, *Industry Performance,* available at CAPP web site at http://www.capp.ca/02b.html
[34] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Annual 1996,* Page 90

gas production rates from Canada's WCSB and the associated new long distance pipelines constructed to connect those supplies to the US market.

Some of these very relevant factors to establishing well head prices in North America are summarised by the US department of Energy Information for the six year period between 1990 and 1996:

- Deliverability (capacity) on the interstate pipeline system increased by more than 15 percent, or 10.9 billion cubic feet per day.
- Pipeline utilization rates also increased, by 7 percentage points, reaching a high of 75 percent (on an average day) in 1996
- Canadian import capacity into the United States increased by 69 percent, or 4.5 billion cubic feet per day.
- Canadian marketed natural gas production increased at an 8-percent annual rate, while natural gas end-use consumption in Canada increased at only a 3.5-percent rate[35]

The North American gas market is highly contested with "more than 120 trading points within the U.S. pipeline network at which trading is conducted by open market traders"[36]. The wholesale physically traded market is approximately 10 times the retail market or 220 Tcf/year and the wholesale paper market is approximately 10 times the physical market or 2200 Tcf/year. The retail market is 22 Tcf/year. Gas is traded in a very sophisticated manner and the top 10 marketing companies dominate the trading activity in the wholesale market. The large integrated gas producers could not maintain a core competence in gas marketing, and have elected to exit gas marketing activities.

Australia's well head gas prices are well above that on average on a world wide basis. In 1996 the world gas price averaged $US 1.37/MMbtu and the world, excluding North America, averaged $US 1.15/MMbtu[37]. "Every gas producing country has its own distinct parameters. The one consistent economic truism throughout the world market economies is that the expected future net back price on an Mcf of natural gas must exceed

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[35] U.S. Office of Oil and Gas of the Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System,* DOE/EIA-0618(98), page vii, available from EIA's web site at http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/deliverability/deliver.html
[36] ibid. page ix.
[37] Enron Corporation, *1997 Enron EnergyOutlook,* page 11.

the sum of the exploration costs, the development costs, and the operating costs"[38]. Short term prices can often be at short run marginal costs or marginal costs. This is the true test regarding the market performance of the upstream sector of Australia's gas industry. Well head prices in Australia, both current and future are, in my view, far above long run marginal costs.

Gas Contracting Practices

Long term contracts, like regulation, are but a proxy for competition. Long term contracts between producers and pipeline companies once dominated the North American gas industry. Although there were multiple producers in any given basin in North America, there were relatively few, and sometimes only one, buyer of gas from producers – the pipeline company serving that basin. The introduction of deregulation or gas reforms in the 1980's introduced multiple buyers, namely marketing companies, local distribution companies, and end users, and traditional "long term" contracts disappeared.

> The collapse of the market in long-term gas supply contracts encouraged development of larger spot and short-term commodity markets for gas and created an opportunity for the rapid growth in these markets. It also created opportunities for new entrants to the market-gas brokers and marketers. These developments, in turn, gave rise to the development of financial instruments, such as forward, futures, and options markets that provide improved liquidity and risk management instruments for commodity markets.[39]

The traditional long term contracts were very similar to that which exists today in Australia. The market – multiple sellers and multiple buyers – decided that better security of supply, prices, flexibility, service, etc were given by shorter term tailor-made

[38] Enron Corporation, *1995 Enron Outlook,* March 1993, page 10.
[39] US Department of Energy – Margaret Jess, *Restructuring Energy Industries: Lessons from Natural Gas,* 1997, page 12, available at the following web site address: http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/1997/restructuring_ene…/peg.htm

contracts. "Gas industry restructuring started as a response to pinned up supplies and inflexible contract practices".[40]

Energy supply security in general and gas supply security in particular is an ongoing concern in North America. Security of gas supply, in both the U.S. and Canada, is achieved not by long-term gas contracts but by monitoring the resource life index (RLI) and by stimulation of investment in the upstream sector. As of January 1993, Enron Corporation estimated the RLI for the contiguous U.S. to be 71 years.[41] The world had a RLI of 186 years as of January 1995[42]. A shorter term measure of supply security is the ratio of remaining reserves to production (R/P). The U.S. had an R/P ratio of 9.5 years in 1993 and just under 9 years in 1995. Worldwide, the life index for the gas resource and the reserves as of January 1997 were estimated to by 200-years and 65-years respectively.[43] Australia has a higher resource and remaining reserves life index than the world average – security of gas should not be an overwhelming concern!

Different buyers want different services! This is a basic feature of any market and applies equally to natural gas as has been proven in North America. A leading U.S. consultant, Dr. William Foster, offers the following comments:

> flexibility of gas contracting, including separate pricing for individual services, has assisted in the market expansion. … flexible contracts became possible only after markets were deregulated, beginning in the mid-1980s.[44]

He explains further:

> The principal characteristic of today's North American gas market contracting practices is flexibility. Different types of buyers will have different supply arrangements. Liquid and competitive markets have allowed marketers to cater to the wide variety of service requirements of the buyers. … While the industry does not have a standard gas supply

[40].ibid, page 8.
[41] Enron Corporation, *The Outlook for Natural Gas,* March 1993, page 6.
[42] Enron Corporation, *1995 Enron Outlook,* March 1993, page 6.
[43] Enron Corporation, *1997 Enron EnergyOutlook,*page 7.
[44] Foster Associates Incorporated, *North American Natural Gas Supply Contracting Practices,* unpublished report, April, 1997, page 1.

> contract, there are several general contract types. A number of these related to the purchase and/or sales obligations:
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> - Base Load – purchase/sales requirement is the same every day of the year,
> - Seasonal Base Load – purchases/sales requirement is the same every day during specified seasons;
> - Swing Supplies – purchase volumes can be decreased or increased after the first of the month, based on need and/or market price;
> - Peak Supplies – gas can be called on during the coldest days of the year; and
> - Spot Supplies – purchases/sales are made on a best-efforts basis, depending on buyer's need and seller's supply availability.[45]

Long term means one to five years in North America's gas industry of today. Although the 30 day spot market peaked at 80% in the early 1980's, gas price indices based on the 30 day spot market set the price for virtually all gas sold in the physical wholesale market. The following excerpt helps explain this phenomena:

> In recent years, the average contract length has shortened significantly: in today's market, much of the gas is being bought and sold on a short-term basis. This is particularly true with respect to wholesale transactions, e.g., marketers buying from producers on a daily basis. The reasons for the shorter contracts include less regulation, higher supply reliability, a well-functioning market, and some uncertainties with respect to gas supply needs (e.g., LDCs). With respect to contracts between relatively small and mid-size end-users and suppliers (producers and/or marketers), the most common contract duration is one year. … The primary reason for the popularity of one-year terms is administration ease, although other reasons include security of supply, and locking in a price or a price formula. … While index pricing is still prevalent, there has been some move to daily pricing and the use of the futures market by some segments of the industry. … LDCs have taken care to develop supply portfolios with a mix of supply and longer term firm contract gas (1-10 years). Today, these longer term contracts represent about 70 percent of LDCs' supply portfolios, and the pricing provisions of these contracts either call for monthly renegotiations or they tie the price directly to the published index.[46]

Although the evolution of the Canadian gas market took a completely different path to that of the U.S., 10 years after deregulation both markets look very similar. "Where there

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[45] Ibid. page 5.
[46] Ibid, pages 7 & 8.

had once been essentially one type of gas supply contract … there now exists an almost infinite number of different contract types”.[47]

In North America the spot price is extensively used to quickly settle temporary defaults in transportation balancing and supply or delivery firm obligations. “Spot markets are a normal mechanism by which commodity traders reconcile imbalances of supply and demand when, as, and if they occur. For example, spot markets in crude oil, petroleum products, and coal are generally within the range of 15 percent to 30 percent of overall consumption”.[48]

An economically efficient and competitive market is characterised by a spectrum of diverse contracting arrangements and the efficient management of risks associated with physical delivery of the commodity and price.

> Efficient management of risk, including risk due to price volatility, is one of the functions that competitive markets perform well. In a highly evolved commodity market, there will exist a diversity of contractual forms and options, which permit the risk of price volatility to be transfered to those parties who can bear the risk most efficiently. This diversity of contractual forms is absolutely necessary for market participants to be able to hold portfolios of supply options that yield a better combination of risks and prices than can be achieved through sole reliance on spot pricing[49]

While this study was performed to examine the dangers of the dominant U.S. spot market, a sole reliance on long term contracts with escalated pricing and infrequent price re-openers is, in my opinion, an even more dangerous situation. Until a paper market exists for gas, market participants will have to manage risks either internally through vertical or horizontal integration or commercially by pursuing a portfolio of contractual terms which diversify its mix of price and supply reliability.

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[47] Macleod Dixon Barristers & Solicitors, *Summary of Canada's Gas Deregulation*, unpublished report, 1994, page 6

[48] *Commoditization of North American Gas Markets: Trading Gas - Trading Capacity* paper by Benjamin Schlesinger and Associates, Inc; Executive Enterprises Inc. Natural Gas Futures Conference, September 20, 1993, Houston Texas, page 4.

[49] *Oversight of Regulated Utilities' Fuel Supply Contracts: Achieving Maximum Benefit From Competitive Natural Gas and Emission Allowance Markets,* by Adam B. Jaffe and Joseph P. Kalt of The Economics Resource Group, April 1993, page i.

A spot gas market was established in 1983 when thousands of 30-day spot gas contracts quickly flooded into the market. "By 1988, more than 300 natural gas marketing companies were in business, and approximately three quarters of all gas consumed in the U.S. was derived in spot markets at one point or another in the supply chain that year."[50] By the 1990's, the U.S. gas market had stabilised to a steady state with a healthy mixture of long term, medium term, and spot transactions - all market based. Gas trade in 1991 was estimated to be as follows:

Spot (1 day - 1 week) transactions - 5%
Spot (30-day) transactions - 40%
Medium-term (less than 1 year) - 20%
Long-term (greater than 1 year) - 35%[51]

Even the conservative gas utilities have drastically changed their gas purchasing behaviour as is illustrated by the largest US gas utility, namely SoCal Gas. SoCal Gas has restructured its gas supply purchases from essentially long term to the following portfolio of interstate gas supplies:

30 day spot – 94%
Long term – 6%

Natural gas imports into the US from Canada represent the longest haul gas in the world. Each new pipeline expansion associated with this gas is a multi-billion dollar project yet the frequency of such projects done since deregulation is at historically high levels- all without take-or-pay contracts. Furthermore, the trend is toward short term contracts:

> Short-term imports accounted for 50.4 percent of total 1995 imports from Canada, exceeding long-term imports for the first time. The trend to short-term imports reflects a growing preference for more market-responsive arrangements.[52]

[50] *Commoditization of North American Gas Markets: Trading Gas - Trading Capacity* paper by Benjamin Schlesinger and Associates, Inc; Executive Enterprises Inc. Natural Gas Futures Conference, September 20, 1993, Houston Texas, page 3.
[51] Ibid, page 4

"Contracts today generally are short term, with flexible pricing and volumetric provisions. … The increased flexibility allows transactions during the period of the contract to occur at prevailing market conditions. Thus, contract participants are not subject to performing under terms that were negotiated at the initiation of a contract many years earlier."[53]

Sanctity of Contracts / Sovereign Risk

Sanctity of contract was embraced in North America at the time of gas deregulation. Canada's gas industy is described as follows:

> Although significant changes resulted from these deregulation steps, one principle that was insisted upon by industry participants and accepted by the governments was that existing contracts should continue to be honoured. Accordingly the long term contracts between producers and pipeline companies continued in effect. With the end of regulated pricing, the parties had to return to negotiated pricing, but the contract was otherwise intact for its stated term.[54]

Many other features of these contracts were re-structured. Each negotiation was pipeline specific, for they reflected trade-offs between producers, pipeline companies as buyers, and governments. For example all take-or-pay provisions were waived by TransCanada Pipelines' several hundred producers in exchange for the reduction of export restrictions by the Federal Government. Producers forfeited their take-or-pay rights for the hope of increased sales to the U.S. Even though the long term contracts continued, many of the terms and conditions were significantly altered to be market responsive.

In North America it was readily decided that governments had significant leverage related to the re-structuring of long term contracts. Take–or-pay soon became a dinosaur; replaced by a demand / commodity price structure in new contracts and diminished, if not

[52] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Annual 1996,* Page 11
[53] ibid, page 85.

completely waived, in older contracts. In Canada, three out of the four pipeline affiliated buyers of gas, namely Transcanada Pipeline affiliated Western Gas Marketing, Foothills Pipeline affiliated Pan Alberta Gas, and Pacific Gas Transmission Pipeline affiliated Alberta & Southern, significantly reduced their take-or-pay commitments. In the U.S., take-or-pay was considered a legitimate stranded cost associated with deregulation and was dealt with by the FERC. A cost sharing formula emerged in the US, whereby Take-or-Pay costs associated with any given gas pipeline were shared by the producers, the pipeline company, and the relevant Local Distribution Companies.

Sovereign risk associated with the intervention of commercial contracts by government agencies such as regulators must never be taken lightly. However, in North America investment levels in all sectors of the natural gas industry have, since gas deregulation, been well above those prior to deregulation. It has been proven that the private sector will embrace government intervention so long as it leads to an open market. The upstream sector of the gas industry in North America began targeting gas exploration for the first time in its 100 year history. Expansions of brown field and the construction of new green field projects related to underground gas storage, gas trading hubs, offshore gas developments, and gas pipelines have been at historically high levels over the past decade in North America. Furthermore, significant efficiency improvements have occurred in all areas of market performance[55].

Natural gas related investments planned for the future are equally, if not more, impressive. In the pipeline sector alone, the following is reported by the EIA regarding the U.S. activity:

> If all the projects currently proposed through 2000 were built, interregional capacity would increase by as much as 14.7 billion cubic feet (Bcf) per day, or about 17 percent, from the level in 1996. Additional

[54] Macleod Dixon Barristers & Solicitors, *Summary of Canada's Gas Deregulation*, unpublished report, 1994, page 4

[55] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Monthly May 1998.* available at EIA's web site at http://www.eia.doe.gov/oil_gas/natuural

> projects that are limited to providing service within a specified region comprise an additional 15.3 Bcf per day of capacity.[56]

The planned gas pipeline activity in Canada is even more impressive.

> … the most extensive development of new capacity during the next several years will occur along the Canadian corridors. At least four new pipelines and several expansions are planned that will expand deliverability from Canada to the U.S. Midwest and Northeast markets and also to Canadian domestic markets. … These expansions could add between 5.9 and 7.0 Bcf per day to U.S. import capacity from Canada during the next 3 years along these corridors, and increase of more than 52 percent over 1997 levels[57].

Regarding the upstream sector, in Canada a record 17,000 wells were drilled in 1997. Gas production has increased to 5.8 trillion cubic feet per year[58].

As is currently the situation facing Australia, North America addressed the tensions between the role of historical long-term gas contracts and the role of competition policy. I think that, in hind sight, most North American gas industry participants would agree that the balance between the two was well established. Contracts generally survived, yet anti-competitive, or terms that were no longer appropriate in the new world of open competition, were re-structured in a timely fashion.

Producer's Ability to Respond

Producers in North America have responded well to the lower well head prices and the need to sell gas under market responsive arrangements.

> The intense competition confronting producers as a result of open access transportation and the lower price environment created a need for new strategies to handle changing conditions effectively. Some of the responses were:

[56] ibid. page x
[57] ibid, page x.
[58] Canadian Association of Petroleum Producers, *Industry Performance,* available at CAPP web site at http://www.capp.ca/02b.html

- More use of short-term, market-oriented contracts and financial management tools to mitigate price risk. Producers' participation in the New York Mercantile Exchange (NYMEX) futures market accounted for 20 percent of the total during the first quarter of 1996.
- Changes in field practices to improve discovery and development operations. Costs have been reduced by consolidating operations, improving efficiency and productivity, and extensively using new technology. …
- Changes in corporate strategies to expand operations and capture economies of scale, attain a more secure position in gas markets, and position themselves for anticipated future conditions. [59]

Greater economic efficiency in the gas industry has been achieved in North America as the industry shifted away from a structure similar to that found in Australia today. Historically there was a reliance on the "hard wiring" of gas supplies to markets, long term contracts, and proved reserves. The new and improved industry relies on market forces, confidence in the ultimate resource, and a reliance on the productive capability of the industry to respond to market forces in a timely fashion. Although this paradigm seems difficult to embrace at this time in Australia for incumbent gas producers, it is a key to successful gas reform. While one cannot fault the incumbent gas producers of Australia for seeking to maintain their market power, the major task at hand is to design an open and free market. This will not be easy, given the many leftovers pertaining to the upstream sector of the old structure that are impeding needed changes.

[59] U.S. Office of Oil and Gas of the Energy Information Administration, *Natural Gas Annual 1996,* Page 81.

Acronyms & Definitions

O.C.S.: Outer Continental Shelf of the Gulf of Mexico

FERC: The Federal Economic Regulatory Commission of the U.S.A.

U.S.: The United States of America

INGAA: The Interstate Natural Gas Association of America

WCSB: The Western Canadian Sedimentary Basin, essentially Canada's only producing gas supply basin (approximately 5 Tcf/year).

EIA: Energy Information Administration of the U.S. Department of Energy

Bcf: Billion cubic feet

Tcf: Trillion cubic feet

LDCs: Local Distribution Companies

UIWG: Upstream Issues Working Group

B.C.: British Columbia (province of Canada)

Attachments

Table 1.0

Resource / Reserve Comparison

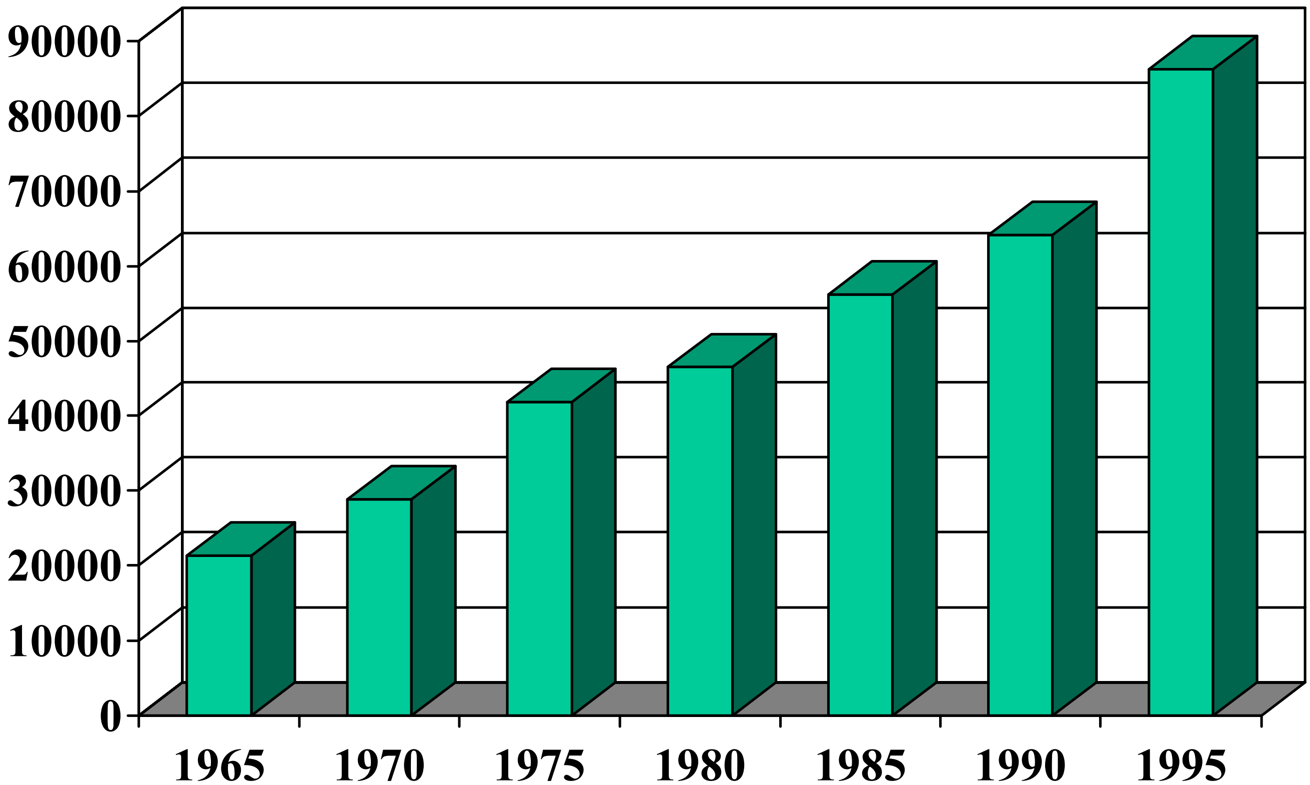
	USA Lower 48 (Tcf)	Canada WCSB (10^9 m^3)	Australia (PJ's)
Annual Production	19.6 in 1992	151.9 in 1995	1005 in 93/94
Remaining Reserves	186 proved as of January, 1993	2015.5 extablished as of January, 1996	22.7 contracted as of January, 1995
Reserve Life Index (yrs)	9.5	13.3	22.7+
Remaining Resource	1300+ year end 1992	20849 year end 1992	92,500+ year end 93
Resource Life Index (yrs)	71	137+	92.5+

Sources: NEB, National Petroleum Council, Enron, AGA, various

Table 2..0 **Average Well Head Prices for Natural Gas in the United States** **($US per thousand cubic feet)** **($/Mcf times approximately 1.032 equals $/MMbtu)**				
1992	**1993**	**1994**	**1995**	**1996**
1.74	**2.04**	**1.85**	**1.55**	**2.17**
Source: Energy Information Administration, *Natural Gas Annual 1996,* Table 1.0 – Summary Statistics for Natural Gas in the United States, 1992-1996				

Figure 1.0

Gas Pipeline Development in Canada (Kms)



Source: Canadian Energy Pipeline Association
Note: Ignores U.S. pipelines serving canadian gas