POTENTIAL LNG PRODUCTION FROM NORTH SLOPE GAS

REPORT FOR

THE STATE OF ALASKA

BY

GAS STRATEGIES

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1. Definitions and Conversions

In this report the abbreviations are used which have the following meanings:

AGIA	Alaska Gas Inducement Act
bbl	US barrels
Bcf	billion cubic feet of gas
Bcf/d	billion cubic feet per day
Bcm	billion cubic metres of gas
Btu	British Thermal unit
EIA	US Energy Information Administration
EU	European Union
IEA	International Energy Agency
JCC	Japanese Customs Cleared Crude price
LNG	liquefied natural gas
mmcf	million cubic feet
MMBtu	million British Thermal units
NGL	natural gas liquids
mt	million tonnes of LNG
mtpa	million tonnes of LNG per year
scf	standard cubic foot

1 cubic metre contains 35.3 cubic feet and hence 1 Bcm contains 35.3 Bcf.

1 Bcf/d is approximately equivalent to 10 Bcm per year and 1Bcm per year is 100 mmcf per day

1 Bcf/d is equivalent to 7.5 mtpa

1 mt of LNG contains 1.38 Bcm or 48 Bcf

1mtpa of LNG is approximately equivalent to140 mmcf per day of gas

2. Summary and Conclusions

This report has been prepared by Gas Strategies Consulting for the State of Alaska and considers the prospects for development of an LNG export scheme based on North Slope gas, to provide a comparison with the pipeline proposed by TransCanada.

An LNG scheme based on 4.5 Bcf per day would produce nearly 30 million tonnes of LNG per year (mtpa). This quantity of LNG is about 15% of today's global LNG market and at start up in 2020 would represent about 15% of demand in the Asia Pacific region, the market area for the project. The alternative schemes proposed using 2.7 or 2.0 Bcf per day of gas initially are still large but would be more easily digested by the market and could be expanded subsequently.

The main country markets in the Asia Pacific region are Japan (currently the world's leading LNG importer), Korea and Taiwan. China and India are emerging as LNG buyers with other countries, e.g. Thailand and Singapore, also seeking supply. A small market for LNG is emerging along the west coast of both North and South America. At present however, there is only one terminal (still under construction) to serve USA and that is in Baja California in Mexico. Opposition to LNG re-gasification facilities from local communities has prevented the kind of expansion of import capacity seen on the Gulf coast of USA.

High shipping costs will limit the ability of Alaska LNG to access the other major LNG market in the Atlantic Basin, where Europe and North America are the main demand areas.

LNG trade in the Asia Pacific region is very different from the gas trade in North America. In none of the countries in the region is there an open and competitive gas market. The buyers have either statutory or *de facto* local monopolies for gas supply. The pricing of LNG is not set by a gas market index, like Henry Hub, but is indexed to the price of crude oil using the Japanese Customs Cleared price for imports (JCC) which is referenced in contracts for all countries.

The exact relationship between JCC and LNG price varies depending on the market conditions at the time when the contract for LNG supply was negotiated: a tight supply and demand leading to a strong relationship approaching parity with crude oil on an energy basis, while in times of more abundant supply this relationship has relaxed allowing LNG prices to be influenced less by changes in oil price and set at a generally lower level

Building an LNG project is a high cost and technically challenging business and to finance such an investment it is necessary to secure contractually, before making the investment decision, all the elements of the chain: proven upstream reserves, transport to the liquefaction plant, the liquefaction plant, shipping and re-gasification capacity. In achieving this it is of primary importance to have long term (20 years plus) take or pay contracts with credit-worthy buyers, for the sale of the majority of the product. While there is a short term/ spot market for LNG cargoes, this market is not sufficiently deep or liquid enough to finance an LNG project.

Consequently, the critical period for the development of an LNG project is about 4 -5 years before the plant comes on stream. At this time pricing terms and the relationship with oil are set. For an Alaskan LNG project projected to start in 2020, the market perception about availability of new long term supply in relation to demand around 2015 will be important to the pricing of the long term contract

Three scenarios have been prepared for the development of supply and demand in the Asia Pacific LNG market for the life of the Alaska LNG project, with particular reference to how it might look in the middle of the next decade. There are many ways in which different supply to demand balances could occur, but the uncertainties over supply are seen to be the more significant.

In general the buyers in the Asian markets are conservative and likely to retain oil indexation in contracts, but with the high oil prices that now prevail, the use of ceilings and floors (S-curves) is likely to be abandoned.

In the high case scenario where there is a tight demand to supply balance, LNG will be priced at a level approaching oil parity on an energy basis. In the base case scenario where supply and demand are more on balance, oil indexation will be retained but with the gas price being less influenced by oil price changes. The low case scenario is a world in which the new LNG being brought to market is seen to exceed demand leading buyers to drive prices down to the level of the alternative market which is the North American market. In this scenario Asian LNG prices become linked to Henry Hub.

The following conclusions are drawn from the scenario analysis:

- An Alaska LNG project will be large in relation to Asia Pacific demand. The growth of capacity will need to be phased over up to 10 years, if the project is as large as 4.5 Bcf/d, in order to secure sales contracts. Even at 2.0 - 2.7 Bcf/d, build up over 5 or more years is likely to be necessary. To achieve this some LNG will probably need to be delivered initially to the west coast North American market to allow trains to operate at full capacity while long term sales to Asian markets ramp up.
- The LNG price exceeds Henry Hub on average around $4/MMBtu in the high case scenario and $3/MMBtu in the base case scenario in the key 2020 period. In the low case scenario LNG pries are below Henry Hub.
- It is not likely that large (in excess of $5/MMBtu Real Terms), sustained differences will occur between North American gas and Asian LNG prices.
- Asian markets are established on a different gas quality basis than North America, which require higher calorific value gas. As a result if the target market for Alaskan LNG is to be Asian markets, as the project plans to take the gas by pipeline to Canada and the lower 48 States, NGL extraction will not be possible if supplying LNG to Asia.

The need for proponents of LNG projects, usually the owners of upstream gas reserves, to be assured of all elements in the LNG chain at the time of the investment decision is a key driver in the structuring of LNG projects. The approaches used worldwide in structuring projects are described, with the majority being established as incorporated joint ventures operating as profit centres. This approach secures control of the capacity for the owners and facilitates expansion where they can supply the gas. It does however impose constraints when third parties wish to develop upstream reserves, requiring them either to sell gas to the liquefying plant or build their own plant at higher cost or face delay in exploiting their reserves. Several projects have now been established on a tolling principle that makes easier the accommodation of different parties in different production trains. Even in these cases however, the main investors are experienced LNG companies with upstream resources. No LNG project has been established by a third party company building a liquefaction plant offering third party access.

AGIA intended to ensure an open access regime to encourage exploration and development of gas in Alaska.

This has to be reconciled with the commercial and financial requirements of structuring an LNG project. We draw the following conclusions:

- In the absence of a strong economic incentive, companies will prefer a pipeline project over LNG. This is driven by concerns over project delays and costs arising from their divergent strategic objectives in the Asia Pacific region and the need to secure long term sales contracts. This contrasts with their ability to transport independently gas to the North American market where volume risk is minimal and sales contacts are not required before investing in pipeline capacity.
- A simple model of a pipeline and liquefaction project established by a third party company as a tolling facility, analogous to the pipeline project, is unlikely to be successful. Although many pipelines are built and run by independent companies that have no gas to transport, no LNG plant has been.
- A pipeline and liquefaction venture could be established that would allow third party access to expansion trains. For example there exist LNG plants where different entities own individual trains but with common services and operations provided across the whole site. These do permit new parties to add more trains as more gas becomes available and the market requires more LNG. The only example that takes advantage of all these features is Egypt LNG (ELNG) where the two trains have different owners. Please refer to Fig 28.

3. Introduction

GSC was commissioned by the State of Alaska to assist it in evaluating the potential for North Slope gas to be monetised through LNG and to be sold into the Asia Pacific basin. Although LNG is sold in Europe and on the East Coast of North America the nearest, largest and generally highest priced market is in the Asia Pacific basin and this was identified as the prime target market. This evaluation will be used to compare the LNG option with the pipeline project proposed by TransCanada Alaska and Foothills Pipeline under the terms of AGIA.

This report provides GSC's contribution to that evaluation which comprised:

- description of the current structure and trends of LNG production and trade
- definition of three scenarios (using oil and Henry Hub price assumptions provided by specialist consultant WoodMac comparable to those being applied in the economic evaluation of the pipeline project) for the future development of the Asia Pacific LNG market, specifying the prices for LNG in each scenario
- an evaluation of the outlook for NGL prices in the Asia Pacific region
- identification of the likely market outlets for Alaska LNG and estimation of the shipping costs of that LNG from Valdez to derive netback values to the liquefaction plant. These values were passed to the project team for calculation of overall project economics.
- discussion of the risk factors that will affect the sales of potential Alaskan LNG
- description of the different drivers and approaches used in structuring and financing LNG projects
- relating the structural approaches for LNG projects to the specific circumstances presented in Alaska under AGIA.

These questions are dealt with in the main body of this report which is a self-standing document. More detailed, background information on Asia Pacific LNG supply and demand, is presented in Appendix A which provides individual country profiles and demand projections and analyses the prospects for supply by assessing each existing and potential supply project.

Unless otherwise indicated data is sourced from Gas Strategies Consulting databases. These contain data from a variety of sources not least our own market intelligence. Historical data on LNG consumption is largely sourced from the importing companies or from official national statistics. Where these are not available, other sources such as the International Energy Agency (IEA) or industry trade bodies such as Cedigaz have been used. Most of these have minor discrepancies and we attempt wherever possible to use the figures that we believe to be the most reliable.

4. Asia Pacific in Global LNG Trade

The way LNG is traded, particularly in Asia, bears little resemblance to the modern US gas market. The vast majority of LNG, especially in Asia Pacific markets, is still sold on long term take-or-pay contracts and moves on fixed routes with very little destination flexibility; this LNG is priced in relation to oil (crude or products depending on the market into which it is sold) except for sales to North American or UK markets. There is a growing spot trade but it is small in relation to the total and suffers badly from regular liquidity crises.

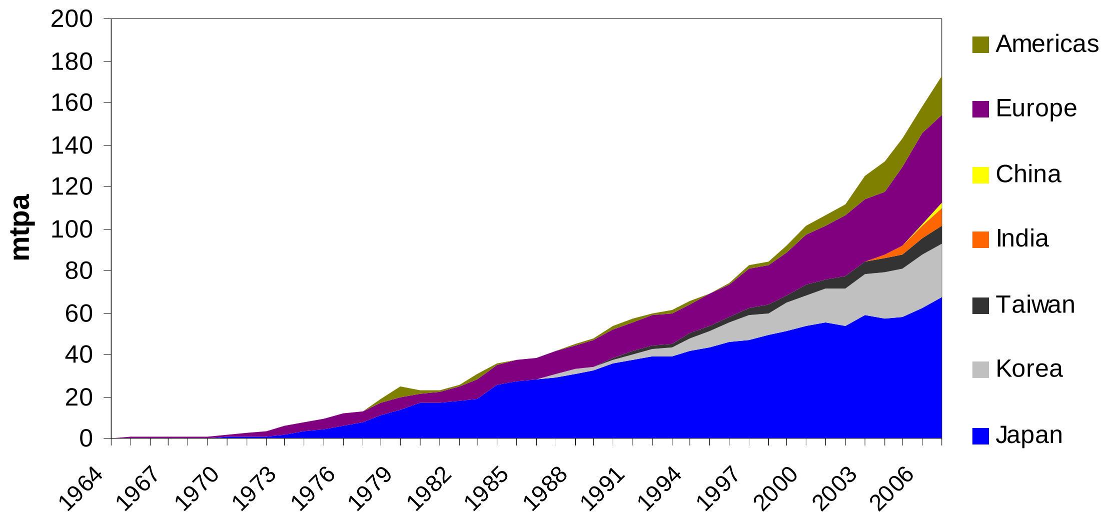
The way LNG is traded to a great extent dictates how LNG projects are developed and this has significant implications for any potential LNG development in Alaska.

4.1 The LNG World

LNG was originally developed as a way of storing gas for peak shaving. It only became viable as a method of transporting gas over long distances when ships for carrying LNG safely and reliably were developed at the beginning of the 1960s. The first regular LNG bulk trade started up in 1964 between Algeria and the UK and the first Pacific trade was between Kenai, Alaska and Tokyo, which started up in 1969. Since then it has grown rapidly, driven by growth of natural gas demand, to feed power generation and as a fuel for industrial and residential consumption. LNG has grown significantly faster than the growth of either energy consumption as a whole or other gas.

Asia is by far the largest market for LNG.

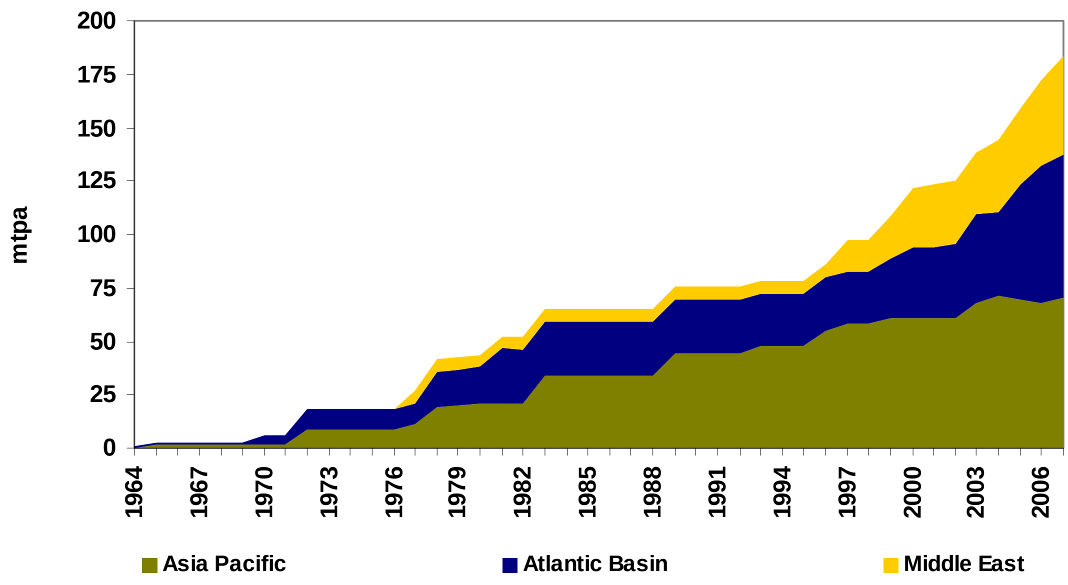
Fig 1 LNG Trade by Importer 1964 – 2007



Source: Gas Strategies analysis

The suppliers of LNG fall into three regional groupings, Pacific Basin, Middle East and Atlantic Basin.

Fig 2 LNG Supply by Region

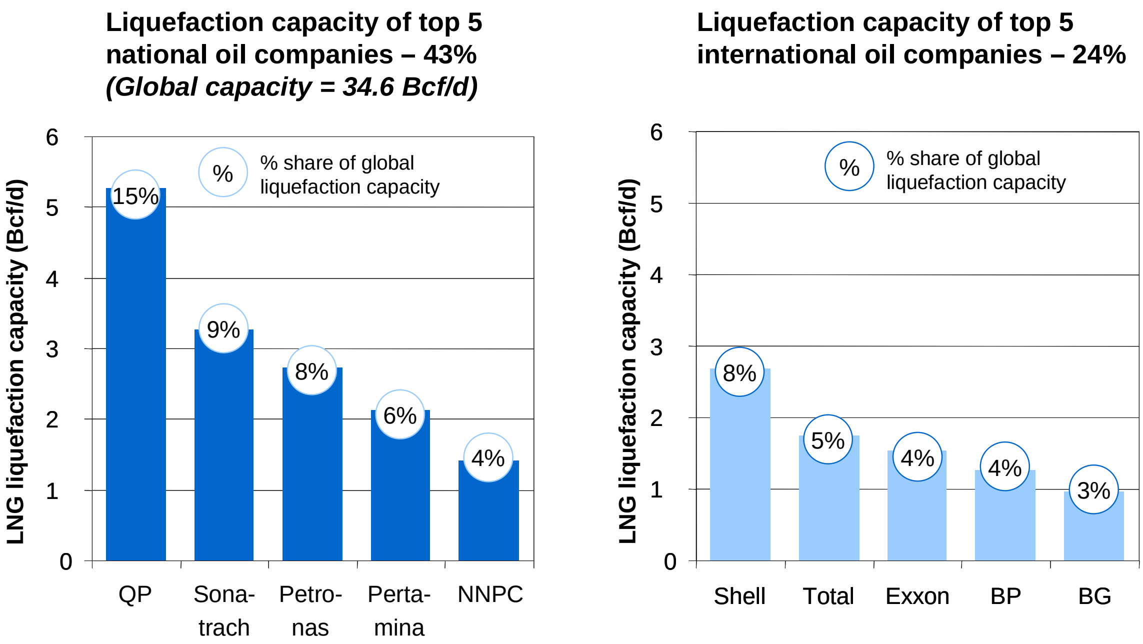


Source: Gas Strategies analysis

The Pacific basin is the largest regional producer but Atlantic Basin and latterly Middle Eastern production capacity has been growing rapidly.

The largest single producer today is Qatar and its dominance is set to increase as Qatar has more capacity under construction than all the Atlantic Basin and Pacific Basin combined. Qatar has two separate liquefaction brand names, Qatargas and RasGas. There are now four Qatargas and three RasGas companies. By and large the RasGas companies are joint Qatar Petroleum (QP) and ExxonMobil ventures (70% QP, 30% ExxonMobil) with some additional very minor shareholders in RasGas 1. Qatargas companies have other shareholders as well as QP and ExxonMobil (Qatargas II and Qatargas IV do not have any ExxonMobil presence).

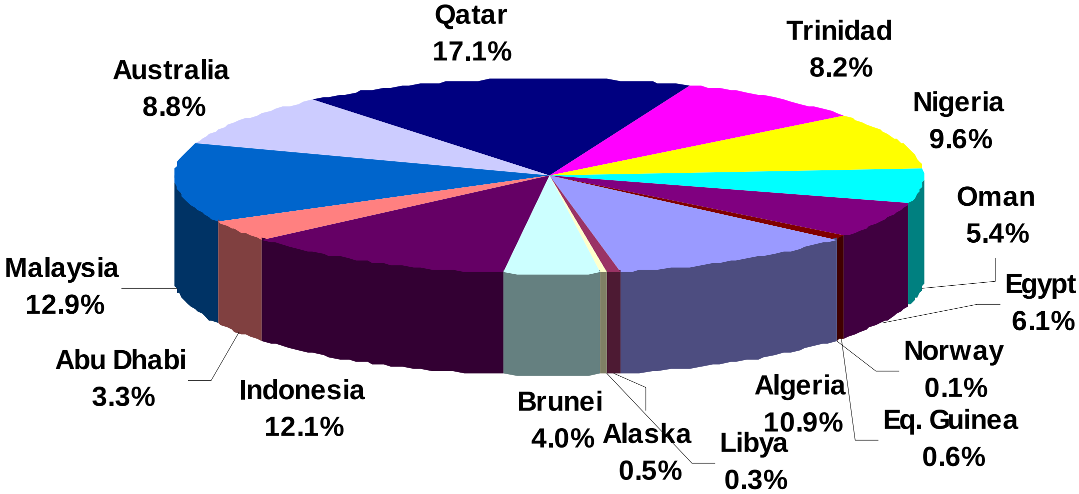
Fig 3 Liquefaction – Major players



Source: Gas Strategies Consulting

Between them, the top five NOCs / IOCs control 67% of the global liquefaction capacity.

Fig 4 LNG Supply by Country



Source: Gas Strategies analysis

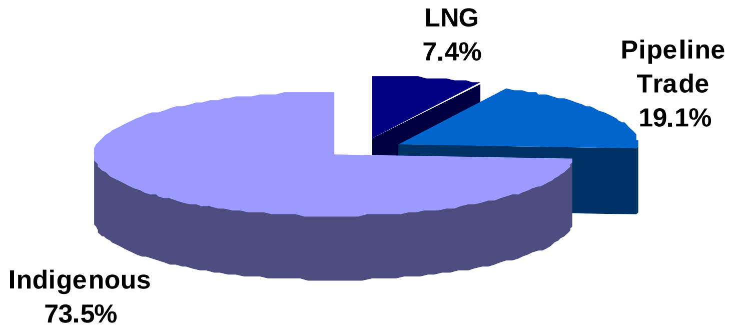
Table 1 LNG Production Capacity

Mtpa	Operating	Under Construction	Total
Pacific Basin	74.6	27.4	102.0
Middle East	47.4	53.5	100.9
Atlantic Basin	70.5	12.1	82.6
TOTAL	**192.5**	**93.0**	**285.5**

Source: Gas Strategies analysis

In spite of its rapid expansion LNG makes up a very small proportion of the world's gas trade; only 7.4% of the total.

Fig 5 Trading of Pipeline Gas and LNG



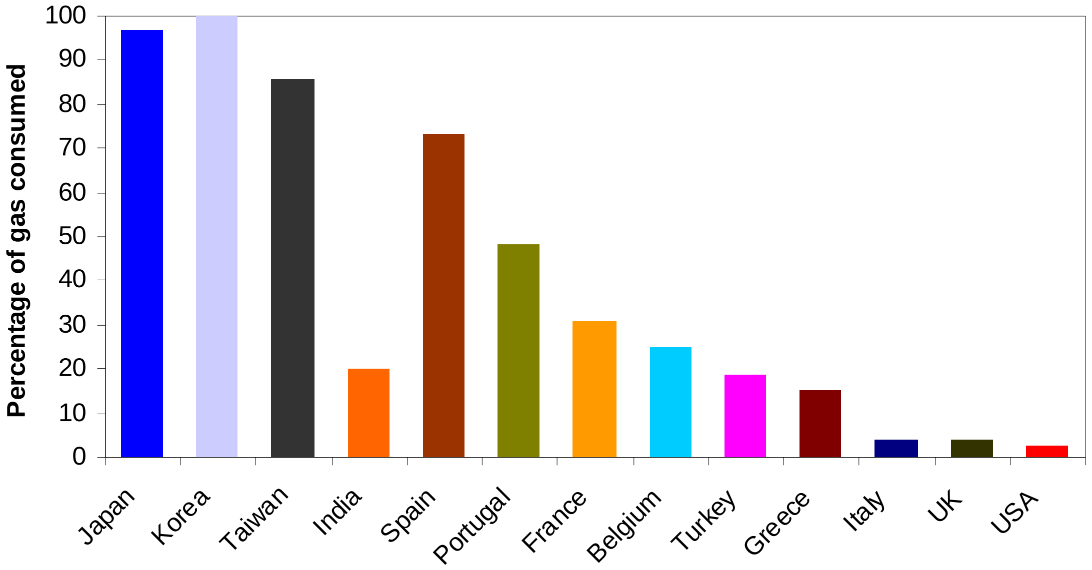
Source: Gas Strategies analysis

4.2 Characteristics of LNG Trade

As stated in the introduction most LNG is sold on long term take-or-pay contracts on rigidly defined trade routes between a seller and a buyer. The volume of spot or short term trade is quite limited.

The reasons for the inflexibility of the LNG trade are quite clear. The main Asian markets, Japan, Korea and Taiwan are virtually totally dependent on imports of LNG; there is no or very little indigenous gas supply.

Fig 6 LNG's Share of Overall Gas Consumption



Source: Gas Strategies analysis

The logistics of gas distribution require that gas must be continuously available. Failure of supply to a gas network is very disruptive to customers and presents a safety hazard as all connections have to be inspected before flow can be resumed. Failures of power supply are also serious, although they do not present the same safety issues. Therefore security of supply is of supreme importance to the main Asian markets, even ahead of price. The buyers are therefore very concerned to lock in supply on a long term basis and not to allow it to be diverted to take account of alternative market opportunities.

The suppliers for their part require a reliable offtake. LNG is very capital intensive and almost all the investment is committed before any income is received. It is therefore of paramount importance to the developers of LNG schemes to have long term assurances of offtake before they make their investments. In the US this can be assured by the liquidity of the US gas market, provided that long term access to an LNG terminal can be secured. This does not hold in Asian markets (and a now smaller number of European markets) where gas supply is open to very limited competition either from alternative supply (pipeline) or from a free market or liberalised structure where one would see greater competition between buyers to procure gas and where gas is freely traded, this is not so. Therefore the suppliers also look for long term take or pay contracts with pre-defined pricing terms to ensure that their investments are remunerated.

This does not mean that there are no shorter term LNG sales contracts. Most LNG plants have performed well above their nameplate capacity. In addition buyers often cannot take full contract quantities at start up but like a gradual build up of supply over two or three years in line with the underlying market growth, this creates a “wedge” of spare capacity. As the LNG plants can usually deliver full capacity very quickly after start up. It is common for these tranches of spare capacity to be sold on short to medium term contracts. Wedge quantities are by definition only available for two or three years and may be sold spot or on short term contracts. Excess capacity is often initially sold on 4 or 5 year contracts to assist buyers in managing market growth with anything left over sold as spot. However, much of this capacity is eventually converted into long term sales.

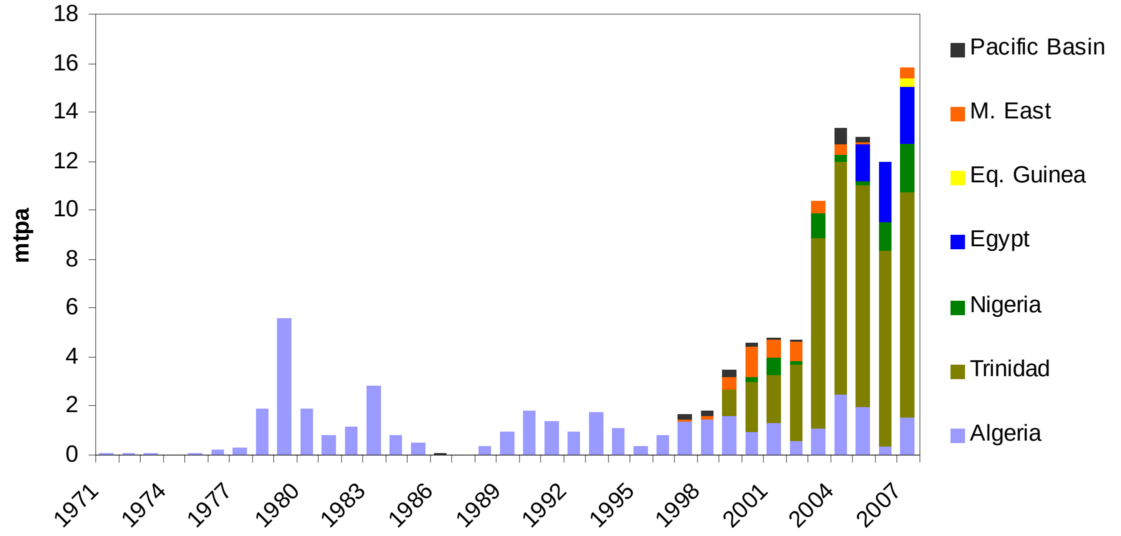
Nevertheless, conditions are changing as the following sections will show.

4.3 Impact of the US Market on LNG Trade

LNG was not able to find a place in the US gas market before 1999 because the US had plentiful indigenous reserves of low cost gas.

As a result gas prices were too low to support the cost of liquefaction and shipping (except for a few cargoes to Boston, mainly in winter). As gas prices rose firstly Atlantic LNG from Trinidad and then other projects began to target the US market, which has grown faster than any other since 2000.

Fig 7 US LNG Imports by Source, 1971 - 2007



Source: Gas Strategies Consulting/US Department of Energy

The opening of the US market to LNG has started to alter the trading model, particularly in the Atlantic Basin. The US gas market is large and very liquid; LNG is a minute component of the whole. The market is not dependent on LNG and LNG volumes are easily replaced by purchases of gas on the spot market; the volumes are so small in relation to the size of the whole market that whether a particular cargo of LNG is delivered or not has no discernible impact on the traded Henry Hub price. The availability of this liquid US market allows the suppliers to take greater risk in other markets. For example if LNG is contracted to Spain and Spain cannot receive a cargo when scheduled, it can be diverted to the US market and sold for the going US price, in other words there is always a market of last resort in the US.

A further source of short term supply is provided by the ability to divert cargoes sold under a long term contract to an alternative, more attractive market. If cargoes are scheduled to be delivered to the US market under a long term contract but the Japanese price is higher, the cargoes can be diverted to Japan and the US contract requirement replaced by purchases at Henry Hub without any penalty (although the fixed costs of regasification capacity in the US will still need to be paid).

This has been partially extended to other markets. Traditional LNG contracts have destination restrictions that prevent the buyer from re-selling to another market. These are becoming less rigid, particularly for contracts supplying the EU where such a condition is viewed as anti-competitive. As a result the major European buyers who buy their LNG Free on Board[1] (FOB) on long term contracts also now have some flexibility to divert cargoes to more lucrative markets, provided that they have enough diversity of supply to make up the shortfall in their home market. It is less easy for the sellers to take advantage of this flexibility but, provided that the primary customer is given a share of the gain, it can sometimes be achieved.

The degree of flexibility from these sources is limited and does have cost implications. Although the market is very liquid, receiving terminal capacity is not. As a result any company wishing to take advantage of the market flexibility must hold and pay for sufficient terminal capacity for the expected volume of trade, whether it is used or not. At present there is no receiving terminal on the west coast of America (Costa Azul in Baya California is under construction). As a result if a cargo is diverted from the Asian market to the US it has to travel to the terminals in the Gulf of Mexico or on the east coast which, for most suppliers will mean a much longer voyage and correspondingly more shipping capacity

Enough spare shipping capacity must therefore be available to carry diverted cargoes. LNG shipping is expensive and there is often very little spare. It is not possible to charter a ship at very short notice, unlike oil tankers. Therefore most companies that want to take advantage of short term LNG trading opportunities invest in some spare shipping capacity, which is unlikely be fully utilised and therefore incurs extra cost.

The third restriction on the ability to switch cargoes between markets is the difference in quality requirements in different markets. The Asian markets require a high calorific value LNG whereas the US and Europe need a lower calorific value. The limitations are discussed in the quality section.

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[1] FOB – Free on Board; Buyer takes delivery as the cargo is loaded into the ship at the loading port. The shipping is the responsibility of the buyer.

As a result the LNG spot market cannot be relied on to clear the market fully. In 2000 and 2001 the LNG producers had significant quantities of spare production capacity from plants that performed above their design capacity or which had recently started up and where the buyers had required a gradual build up to full offtake. However, there were very few LNG ships that were not fully used on long term trade. As a result much of the spare capacity remained unsold, in spite of the market need, because there were no ships available for charter. In contrast during 2006 and 2007 there was a high demand for more LNG and plenty of underused shipping (the earlier shortage of ships had provoked some speculative building of LNG carriers for the first time in 20 years). All the producers sold what spare capacity they had left but could not meet the market need; spot prices rose to unprecedented levels for the cargoes that were available (see Fig.15).

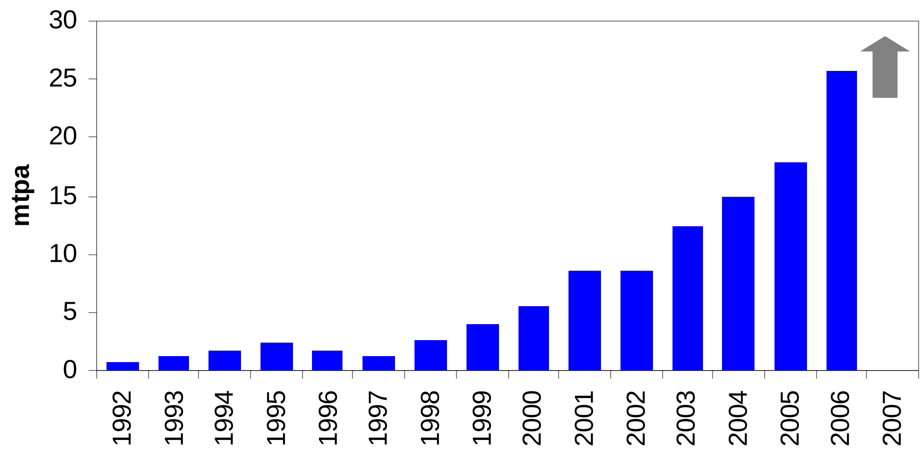
Nevertheless, the opening of the US market has driven most of the growth of the short term LNG trade.

The availability of an alternative market, from a remerging US market, poses something of a threat to Asian buyers as, although it can provide them with a safety valve and a source of supply if they have misjudged demand, it can also compromise their security of supply. As a result Asian buyers increasingly prefer to buy FOB, to control the shipping element of the LNG chain and the ultimate destination of the cargo.

The impact of access to the US market will become more apparent in the Pacific when the Costa Azul terminal in Baja California starts to receive LNG, which now seems likely to be in early 2009. This may lead to a rather closer relationship of spot prices in Asia to US west coast prices but is unlikely to fundamentally change the way in which LNG is traded for the foreseeable future.

The quantities shown as spot sales in the figure below need to be taken with some caution.

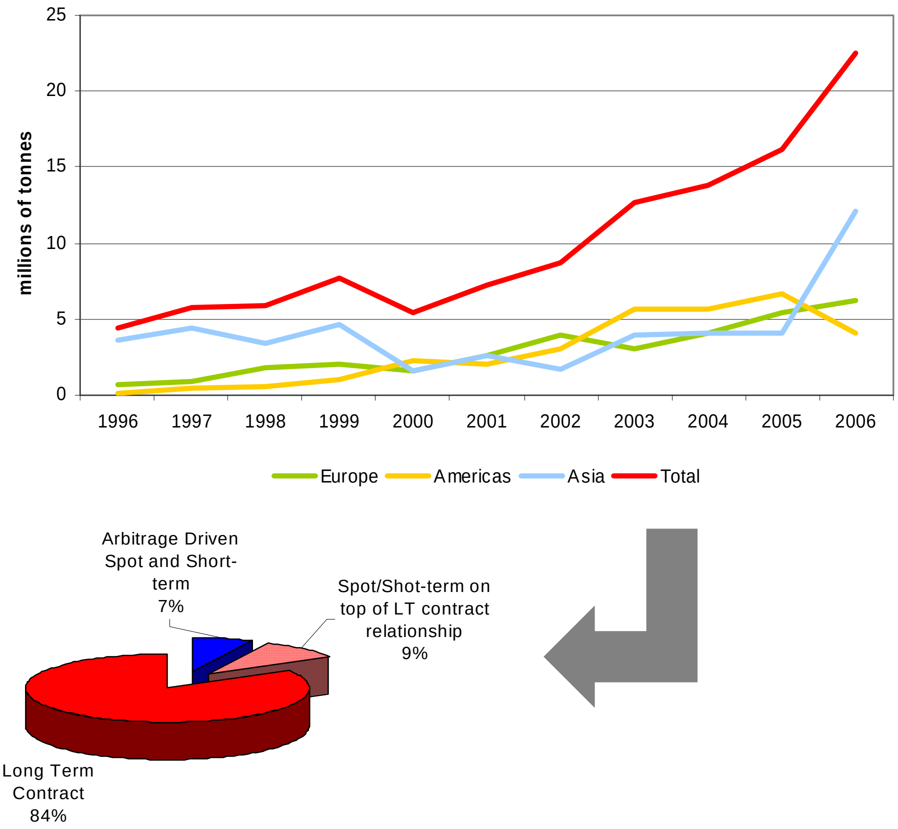
Fig 8 Global LNG Short-Term Trades, 1992-2006 (mtpa)



Source: Gas Strategies /, GROUPE INTERNATIONAL DES IMPORTATEURS DE GAZ NATUREL LIQUEFIE (GIIGNL)

It covers all sales of two years duration or less and a sizeable proportion is made up of extra sales by Pacific producers to existing Asian buyers from spare capacity and priced at the same price as the base contracts. Sales to Asian markets rely on strong relationships of trust between buyers and sellers and the sellers generally feel constrained to offer spare capacity to their existing buyers before offering it on the open market. The relative importance of the Atlantic spot trade compared with the Pacific is shown in the chart below. The Atlantic Basin market (consisting of Europe and America) has shown stable growth since the late 1990's and as of 2006, short term cargoes made up 20.7% of all cargoes compared to 12.8% in the Pacific Basin.

Fig 9 Markets for Short Term Cargoes



Source: Gas Strategies analysis

4.4 LNG Quality and Short Term Trade

The desire to switch LNG from one market area to another and the growth of short term trade has led to problems of quality incompatibility between different LNG supplies and market requirements. Specifications for LNG sold to Japan, Korea and Taiwan differ from LNG sold to the USA (and Europe), primarily in Gross Heating Value (GHV) where the USA seeks lower GHV than the Asian Markets. This has caused problems with handling LNG designed for Asian markets at some US receiving terminals, notably Cove Point.

The driver for the quality specification is the design of the gas distribution system that the LNG feeds. There is a limited range of quality that a gas burner can handle safely, particularly small burners in domestic appliances. The Asian markets were developed on the basis of LNG of relatively high heating value and are therefore designed to use rich gas. Even so they may have to inject extra propane to raise the heating value of some LNG they take.

Table 2 sets out the required quality for Kogas (the Korean state gas company) and Tokyo Gas in comparison with the specification for the Everett terminal in Boston. Tokyo Gas is a representative Japanese specification. Virtually all the other buyers have the same calorific value requirements but there are some minor detailed variations e.g. in sulphur specifications.

Table 2 Key LNG Quality Criteria

	Unit	KOGAS		Everett		Japan (Tokyo Gas)	
		Min	Max	Min	Max	Min	Max
Nitrogen	Mol %	0.00	0.20	-	1.0	-	1.0
Methane	Mol %	85.0	100.0	85.0	100.0	85.0	
Ethane	Mol %	0.00	10.0	-	10.0	-	-
Propane	Mol %	0.00	4.0	-	2.5	-	-
Butanes and Heavier	Mol %			-	2.0	-	2.0
Pentanes and Heavier	Mol %			-	0.10	-	0.1
Hydrogen Sulphide	Mg/Sm3 Mg/Nm3	0.00	5.0	-	5.5	-	 4.8
Total Sulphur	Mg/Sm3 Mg/Nm3	0	30	-	29.7	-	 28.0
Mercury	ng/Sm	0	10	-	10.0		
Gross Heating Value (Volume based) **"Expected" Value**	Btu/scf	1,060 1,080	1,130 1,130	1,000	1,082	1,050 1,080	1,170 1,130

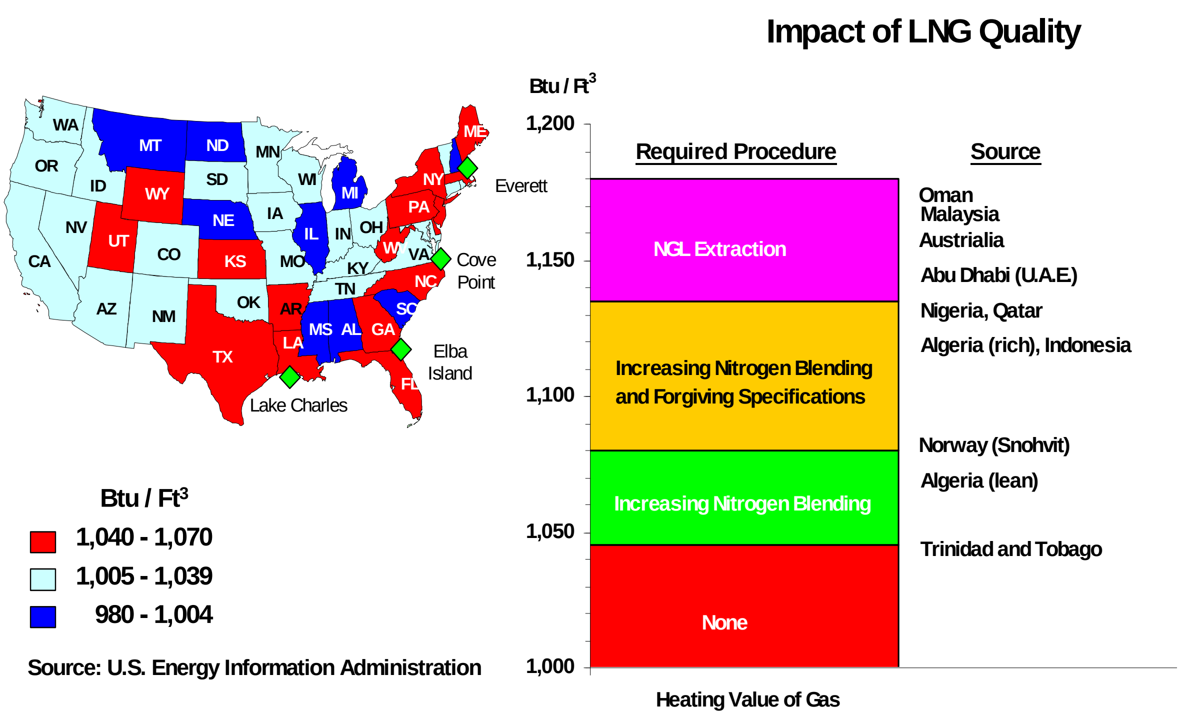
Source: Gas Strategies Consulting

It is important for both Kogas, and Tokyo Gas, that the GHV is in the range 1080 -1,130 Btu/scf as they require this specification to meet their pipeline quality specifications. (Although they can, if necessary take a lower heating value, they need to blend it with other LNG or LPG to adjust the quality). Kogas has recently obtained a discount if LNG is delivered in the 1060 – 1080 Btu/scf range. The Kenai project does supply LNG at about 1020 Btu/scf to Tokyo Electric and Tokyo Gas, essentially because its gas supply is very lean and it cannot make a richer LNG. But the quantity is only 1.7 mtpa in a total Japanese market in excess of 60 mtpa and can be handled by blending with richer LNG in the very large portfolios of the buyers. The emerging markets in Asia, India and China appear to be largely following the established Asian countries. The Indian specification requires heating value in the range 1050 – 1170 Btu/scf. The Chinese market is very fragmented and poorly regulated but the one LNG supply currently going there is from Australia's North West Shelf project which is at about 1130 Btu/scf.

For sales of LNG to the USA normally the GHV range required is 1000-1081 Btu/scf depending where the LNG is delivered. Lake Charles, however, has so much blending capability that it can take LNG from any current supplier. The Costa Azul terminal in Baja California is intending to install nitrogen injection facilities in order to be able to adjust Asian specification LNG to US and Mexican requirements.

Fig 10 provides an overview of the average natural gas heating value for certain US regions.

Fig 10 USA - Impact of LNG Quality



Source: Gas Strategies Consulting/ Energy Information Administration (EIA)

Examples of the quality supplied by a number of LNG projects are shown in the table below:

Table 3 Qualities of LNG by Supplier

Project	Btu/scf
Alaska	1020
Indonesia (Tangguh)	1030
Trinidad	1050
Egypt	1050
Algeria (1)	1080
Algeria (2)	1110
Sakhalin	1100
Indonesia (Bontang & Arun)	1110
Malaysia	1120
Qatargas I / RasGas I	1125
Nigeria (pre – LPG extraction)	1125
Australia NWS	1130
Abu Dhabi	1140
Brunei	1140
Oman	1160
Libya	1160

Source: Gas Strategies Consulting

As can be seen, projects designed to supply solely European and US markets such as Trinidad and Egypt control heating value accordingly. The Tangguh project does not supply the Japanese market or Kogas. Some is intended for use in power generation (which is less sensitive to gas quality) in China and to an independent power producer in Korea with the rest destined for the US.

It is most unlikely that the specifications will ever be harmonised between the different markets as this would require an enormous programme of conversion and burner replacement.

4.5 LNG Pricing

4.5.1 Regional Pricing

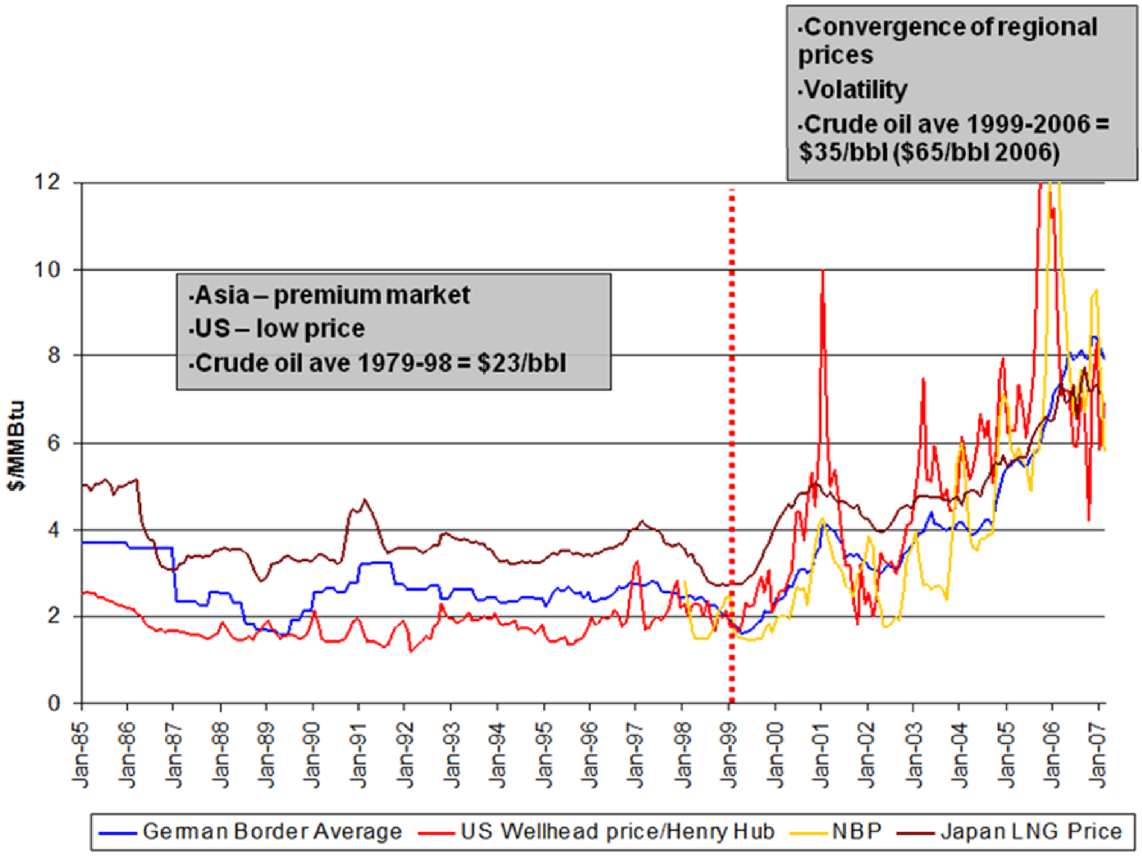
There is not enough gas trade between regions fully to harmonise world gas prices. It has already been shown than only about 28% of gas is traded internationally; most gas is sold in the region where it is produced. There are three main pricing regimes.

- In North America prices are driven by Henry Hub. The landed price of LNG is Henry Hub plus or minus any basis differential to the landing point minus the cost of regasification and the buyer's margin. In the Gulf Coast this is usually works out at about 90% of HH.

- In Asian markets, as a general rule, prices are set by a formula that links gas price to crude oil price (normally Japanese import prices, known as JCC). These price formulae are set at the time of the initial long term sale in response to market conditions at the time and reviewed periodically (usually once every five years). As a result there is no single market price and when the market moves from surplus to shortage over quite short periods, as it has done in recent years, quite large price differentials between individual contracts open up (see Fig 14).

- In Europe (except for the UK where there is a traded market similar to Henry Hub) gas prices remain contractually linked to oil product prices. There is some progress towards liberalisation of continental European markets and there are some emergent spot markets e.g. in the Netherlands and Belgium. The spread of prices is narrower in Europe than in Asia and tends to be set by pipeline supply rather than LNG.

Fig 11 Prices of Pipeline Gas, LNG and Crude Oil



Source: Gas Strategies analysis

4.5.2 LNG Pricing in Asian Markets

4.5.2.1 The Era of Stability

LNG pricing in Asian LNG markets followed a stable pattern from the major fall in oil price in early 1986 until the year 2000.

During this period virtually all projects moved to a price formula of the form:

$$P = 0.1485JCC + \alpha$$

Where:

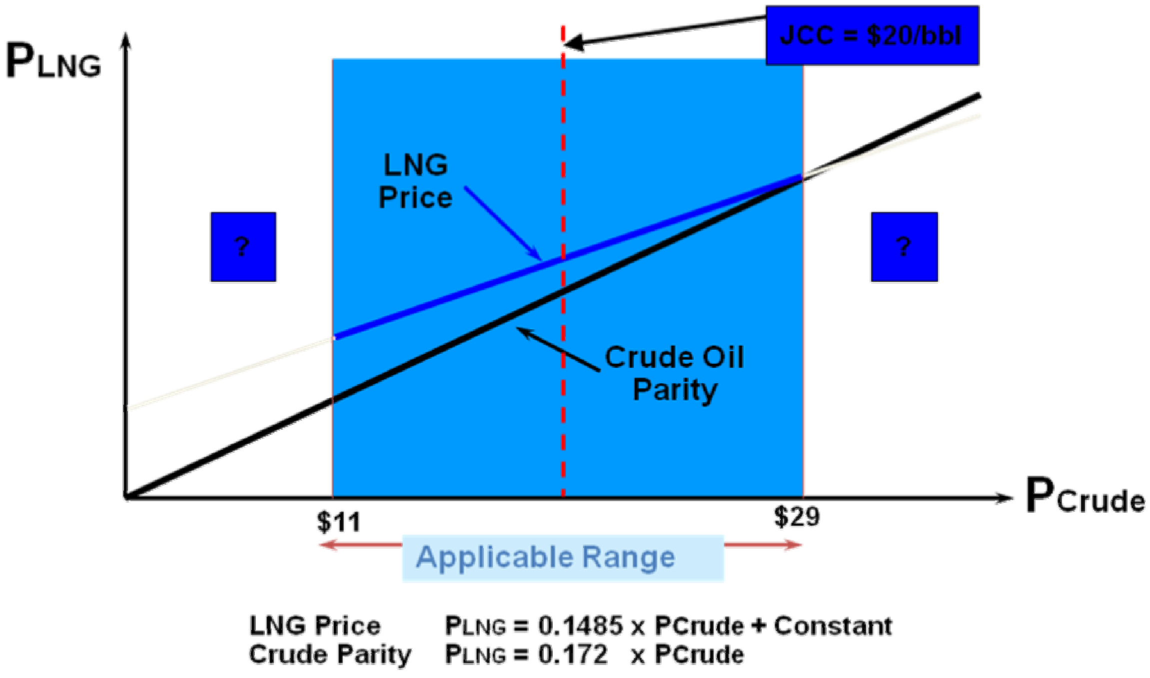
P is the LNG price in $/MMBtu

JCC is the average price of crude oil imported into Japan (popularly known as the Japanese crude cocktail).

α is a constant, which varied between 60 and 90 cents, depending on project.

This formula leads to a price for LNG at $20/bbl that is at about a 15% premium to the thermal equivalent value of crude oil. However this premium declines as oil price rises, and above an Oil price of $26/bbl to 29/bbl (depending on the value of α) the premium disappears and at higher prices becomes a discount.

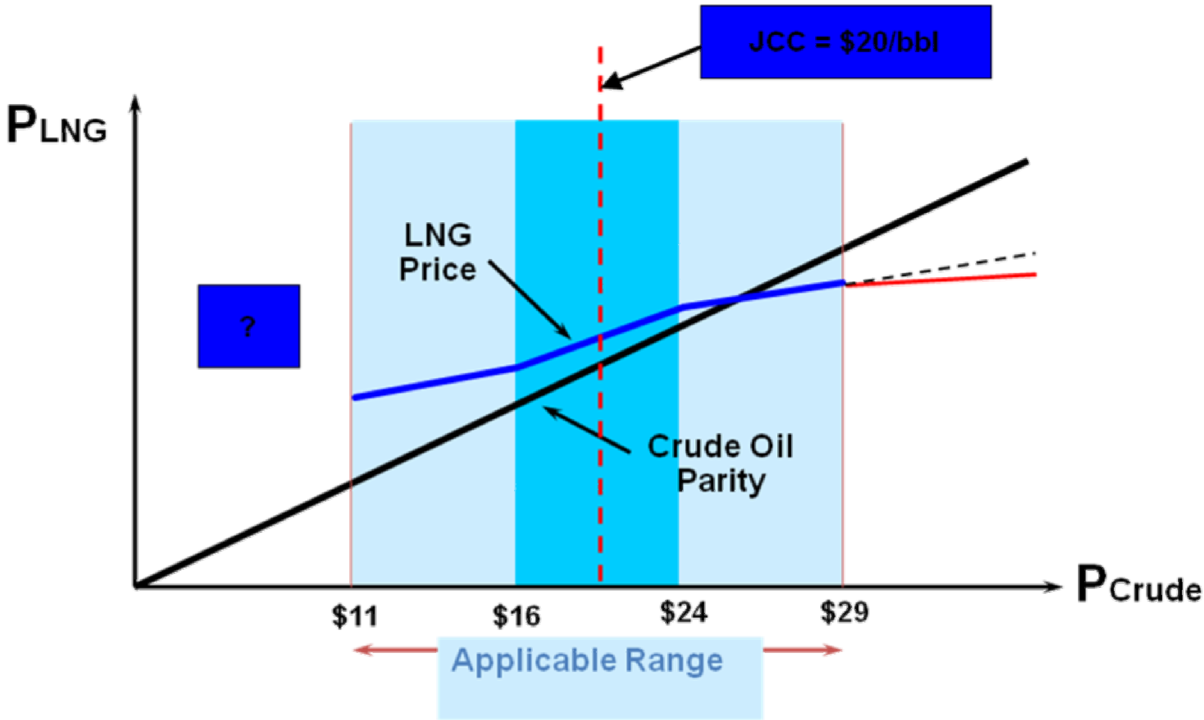
Fig 12 Asian LNG Price Formula



Source: Gas Strategies Consulting

Because the producers feared the impact of low oil prices on the economics of their LNG schemes, they asked for protection at low oil prices in exchange for surrendering some upside at high oil prices. This was achieved in Japanese contracts (but not in Korean and Taiwanese) by the introduction of a so-called “S” curve element in the pricing formula as shown in Fig.13.

Fig 13 Japanese "S" Curve for LNG Pricing



Source: Gas Strategies Consulting

The 0.1485 multiplier was changed to around 0.07 below and above trigger oil prices, which were usually $15-$16/bbl for the low point and $24-$25/bbl for the high point and adjusting the constants to match at the trigger points.

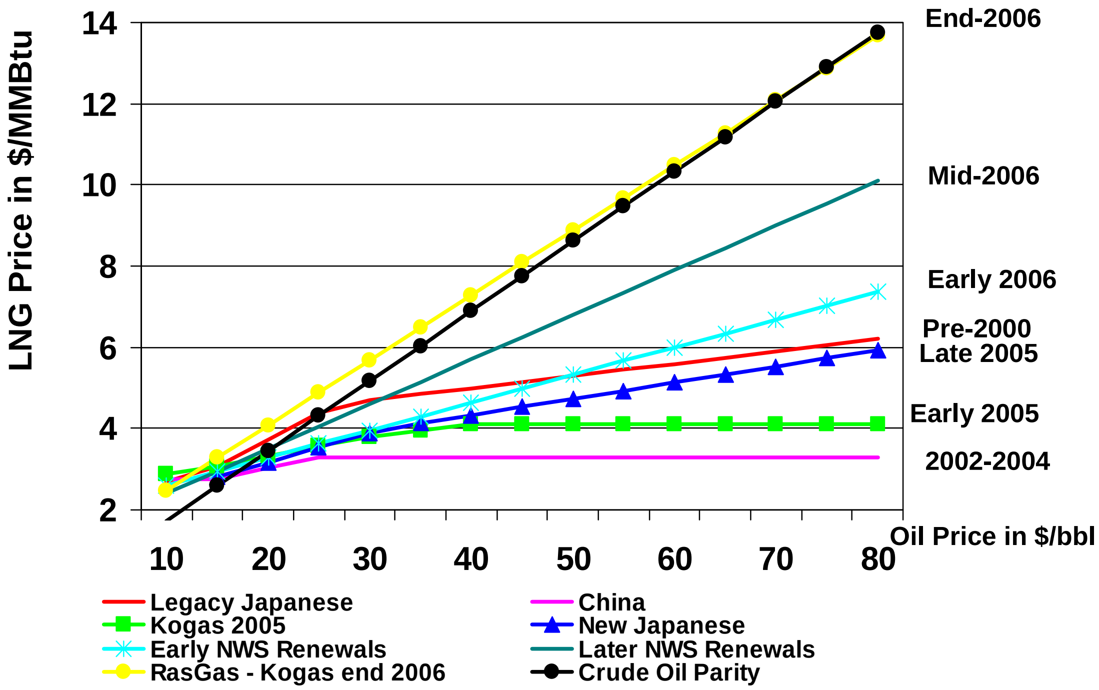
Another feature of the Japanese contracts which did not feature in the Korean and Taiwanese deals was that the price formulae only applied over a range of oil prices from $10-$11/bbl to $29-$30/bbl. If oil prices were to go outside these limits the parties were required to re-negotiate.

There were a number of re-negotiations during this period of nearly 15 years that resulted in changes in price but they were essentially adjustments to the α-term. Their impact was minor compared with the changes in price caused by the fluctuations of oil price.

4.5.2.2 The Brief Buyers' Market

From 2001 to 2004 there was a short buyers' market for LNG in Asia. The root causes of this were the long period of slow growth of the Japanese economy and a relatively large quantity of new LNG coming to market. The situation was first tested by China, which solicited bids for LNG to supply its new Guangdong receiving terminal on the basis of a much weaker linkage to oil price (the multiplier was 0.0525 instead of the traditional 0.1485) and with a floor at \$15/bbl and ceiling at \$25/bbl. This produced prices significantly lower than existing Japanese contracts (about \$0.75/MMBtu at \$20/bbl oil price). The ceiling price in the Guangdong contract means that the difference is enormous at current oil prices. Clearly the surge in oil price over the past two years was not foreseen.

Fig 14 Japanese, Korean, Taiwanese and Chinese LNG Prices Related to Crude Oil Price



Source: Gas Strategies Consulting

A number of other contracts were negotiated in this period, notably from Tangguh to Korea and China, Sakhalin to several Japanese buyers and Korea, Australia to some Japanese buyers and Yemen and Malaysia to Korea, which, while not as extreme as the Guangdong contract had weak linkage to oil (multipliers between 0.05 and 0.08) but without ceilings.

4.5.2.3 The Sellers' Market Since 2005

The buyers' market did not last long. Japanese demand started to recover at the same time as Indonesia discovered that it could not maintain its contracted level of deliveries as the fields in East Kalimantan started to underperform. One or two other LNG plants suffered start up delays and reliability problems. This was compounded by a series of problems with Japanese nuclear power generating plant which increased their demand for gas in the power sector. Finally, although there appeared to be a large number of LNG projects trying to proceed, in reality most of them were held up by political, organisational and spiralling cost issues. Only one LNG project, in Peru, took its final investment decision in 2006. Three more went ahead in 2007, Pluto in Australia, Angola and the rebuild of the damaged Algerian plant at Skikda. These last two are primarily Atlantic basin suppliers.

The result has been a major hardening in LNG prices in Asia relative to oil for those who do have LNG to sell. The later contracts agreed by Sakhalin and the Australian North West Shelf project have achieved prices approaching crude oil thermal parity (which is $17.2/MMBtu at $100/bbl oil price). The highest reported price has been from RasGas in Qatar to Korea, which is reported to be 0.162JCC + $1.00 which does indeed give $17.2/MMBtu at $100/bbl oil. Spot prices have regularly gone higher than this to attract cargoes away from the US market.

The rapid rise in oil prices has increased the price in all the contracts (except for the Guangdong contract) but has also opened up a much wider gap between those contracts with "S" curves and those without. Most of the Japanese contracts are working well outside their contractual price limits but operate the existing formulae as an interim measure until revised prices can be agreed.

So far these new price levels seem to have done little to stimulate new supply as they have coincided with very rapid increases in the cost of new plant, which has far outpaced the rise in price. It is reported that Pluto was only able to proceed after it had managed to get significant protection from price falls at low oil prices from its Japanese buyers.

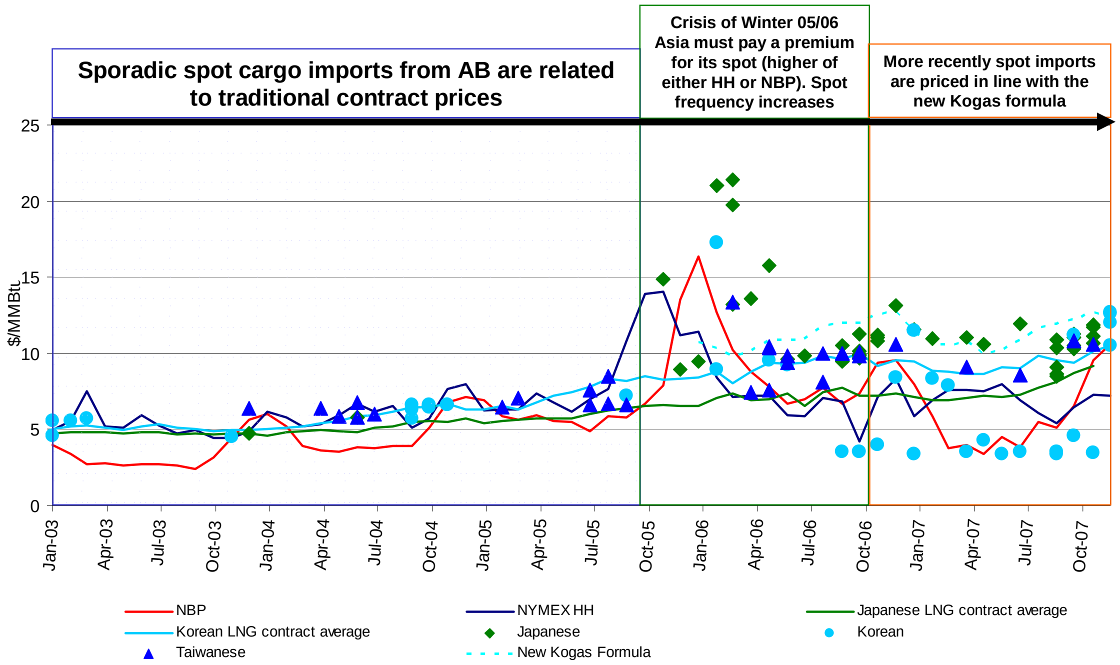
4.5.2.4 Summary of the Current Position

The changes in price since 2001 have been very rapid by LNG standards, bearing in mind that price formulae are generally only adjusted about every five years and that the negotiations may take a year or two to complete. As a result there are still many contracts that retain the old formula. Only a few of the low priced deals from 2001 to 2004 have started up yet and the higher priced recent ones are, at best, under construction. However, the wide spread of prices presents an unstable situation and there is much renegotiation in progress, which is likely to result in an evening out of prices. It is rather early in the process to be sure where they will settle but we expect the most likely outcome to be a re-establishment of the traditional 0.1485 linkage but without "S" curves or price caps. This forms the basis for our central price case.

4.5.3 Spot Prices

As already mentioned, there is currently a global shortage of LNG supply and spot prices are therefore high. They are generally set in relation to the alternative market (usually the higher of UK and US prices) plus a freight differential (which can be substantial as LNG shipping is expensive) and something of a scarcity premium. As a result spot prices bear little relation to long term prices.

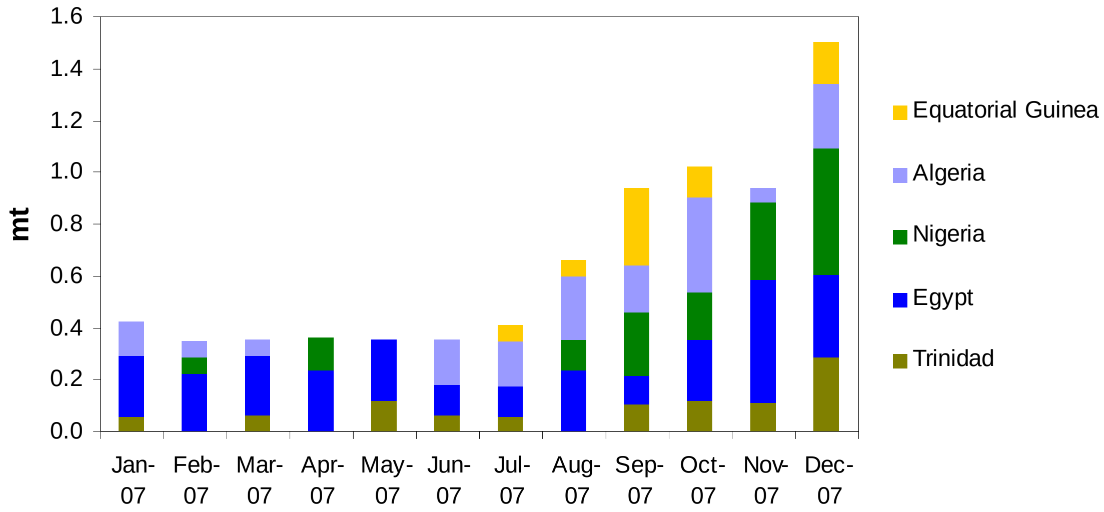
Fig 15 Selected Asian Spot and Contract Prices



Source: Customs data Japan (METI), Korea(MOCIE), Taiwan (DGC) / Gas Strategies Consulting

Because the Asian markets are so dependent on LNG they will normally be prepared to outbid the other regional markets for spot cargoes when they need them. This has had the result of pulling cargoes out of the Atlantic basin in spite of the greatly increased shipping distance.

Fig 16 Atlantic basin sources of Japanese LNG Spot Cargoes



Source: Customs data Japan (METI) / Gas Strategies Consulting

The break even cost of these diversions is quite high as the following calculation shows.

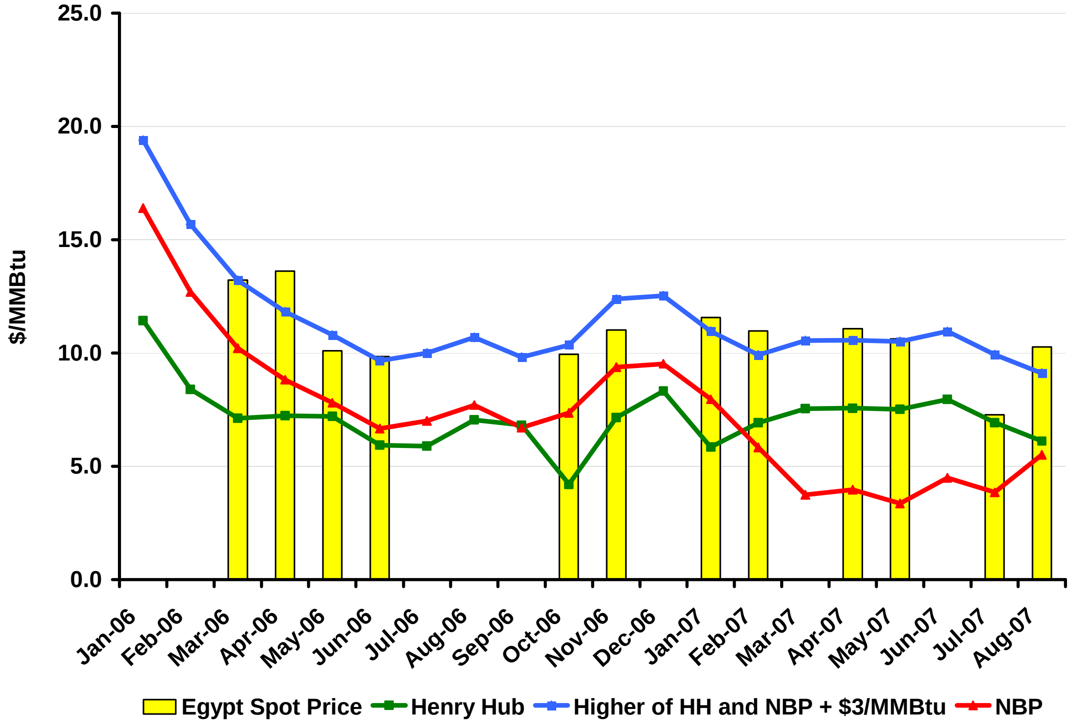
Table 4 Breakeven Pricing for LNG Cargo Diversion

	In $/MMBtu
Henry Hub Price	$7.50
Less differential L. Charles/Henry Hub	-$0.15
Less Buyers margin	-$0.10
Price at Outlet of Terminal	$7.25
Less Terminal Cost (Fee and Fuel)	-$0.45
LNG DES Lake Charles	$6.80
Less Shipping Nigeria-L.Charles	-$1.30
LNG FOB Nigeria	$5.50
Plus Shipping Nigeria-Korea	+$2.20
LNG DES Korea	$7.70

Source: Gas Strategies Consulting

Because supply has been so short, sellers have been able to command significantly more than a breakeven price. As can be seen the prices realised by Egypt for spot sales into Japan appear to be close to a \$3.0/MMBtu premium over the higher of Henry Hub and the UK NBP market price.

Fig 17 Correlation of short-term sales to Japan with NBP and HH prices



Source: METI/ Gas Strategies Consulting

However, no project developer would be willing to invest in an LNG project without long term contracts on the basis that it could sell all the output in the spot market. There is simply not enough liquidity in the spot market to make it any basis for making an investment of several billion dollars that relies on 20 year cash flows to earn a satisfactory return.

4.6 Implications for Alaskan LNG

The logic for Alaskan LNG is to exploit the value of markets in Asia to provide netback prices higher than those available from US markets. A pipeline is likely to be the preferred option for supplying the US market.

As a result the promoters of the project will have to commit in advance to long term (generally 20 – 25 year) sales contracts. Buyers will expect these to be backed by sufficient proven and committed reserves to fulfil the contract obligations and will require a reserves certificate to demonstrate it. There have been two projects which have had long term contracts of less than 20 years (17 in both cases) as a result of lack of reserves; one of those fairly quickly proved the extra gas and extended the term. The other remains a short contract.

Contracts will need to be in place for virtually the full output (or sufficient at least to cover the capital and financing costs) of the liquefaction plant before it will be able to commit firmly to construction. This will require back to back long term commitments for feed gas and for pipeline capacity in the line from the North Slope.

Alaska is working on two feed gas scenarios, a lean gas of 1083 Btu/scf and a rich gas of 1133 Btu/scf. After LPG extraction these would give LNG of 1006 Btu/scf in the planning case.

As the base assumption is that Alaskan LNG will be sold in the Asian market, there is clearly neither need nor is it a good idea to extract LPG. The lean gas case is already close to the lower limit for acceptability in the main Asian markets. Accordingly, it suggests a practical limitation on the ability of an LNG project to facilitate “value added” jobs associated with a petrochemical industry in Alaska. Some propane could be taken out of the gas stream during liquefaction at Valdez while continuing to meet specification requirements. This could be important for in-state energy needs. However, there appears no practical opportunity for the extraction and processing of ethanes, butanes and pentanes plus.

The project will be in competition with other LNG suppliers trying to market into Asia in the same timeframe. Pricing will be in line with Asian long term prices at the time that the deals are struck. These prices will be linked to crude oil price but the strike price will reflect the state of competition at the time. Once the deal has been done, however, the supply becomes locked into the market for the full duration of the contract and is not exposed to any direct competition. Generally there are price re-openers that allow the price to be re-visited at intervals of about five years. At these points there is usually some adjustment of the price to fine tune it towards the prevailing market conditions at the time but these adjustments are generally relatively small, compared with the impact of changes in oil price through the normal indexation mechanism. If prices in the USA and/or Europe were below (or above) Asian prices at the time they would be used as a lever towards price convergence (see following section).

4.7 Global Convergence of Gas Prices

The presence or absence of a contractual gas price linkage to oil in different markets creates the potential for differences in gas prices to emerge around the globe at least in the short term. In particular, for a potential Alaskan LNG venture the divergence between North American, Henry Hub based, prices and Asian oil-indexed LNG prices will be critical. We believe it is likely that Asian oil-indexed LNG prices will exceed Henry Hub prices on average and over the long term because the main Asian markets are totally dependent on LNG for their gas supply and are prepared to pay a security premium to ensure supply. However, economic logic suggests that this long-term premium is bounded as there is some LNG on flexible terms that can be diverted from low to high priced markets. This is unlikely to be enough to eliminate the differential totally but even in a world of high oil prices we do not see sustained, long-term differences in Asian and North American prices exceeding $5.

As can be seen in Fig 11 there is a relationship between HH prices and oil price as gas does compete with oil products, which tends to limit the divergence between HH prices and oil price. However, the relationship is complex and there can be wide short term divergences; HH is very volatile. During the 1980s and 1990s when there was a surplus of gas in the US market HH was driven largely by the cost of gas and by competition with heavy fuel oil. Since 1999 gas shortages are possible and as much of the market is inelastic in the short term this will produce sharp price spikes. In addition much of the low priced feedstock market and applications in direct competition with fuel oil have been shed and competition is now largely with gas oil and in power generation against a mix of fuels (taking account also of different generating efficiencies). The cost of new gas has risen significantly raising the floor.

When gas prices do diverge across the regions the main agent that can drive convergence will be redirection of LNG flows. Prior to 1999 LNG flows into the US were almost non-existent and there was therefore no agent for convergence.

As discussed above there are now reasonably substantial flows of short term LNG cargoes driven by arbitrage, most recently these have been drawn to the Asian market but previously North America and subsequently Europe was the prime target. Although these flows are important for the individual traders to earn premiums, they are not sufficiently large to set prices in the major markets of North America and Europe. The reason is that these markets are dominated by pipeline supply and it is pipeline supply that ultimately controls price.

The quantity of LNG targeted at the US market is set to increase substantially over the next three to four years as new capacity under construction targeted for the Atlantic Basin comes on stream. This amounts to 70.3 mtpa from Qatar, Yemen, Nigeria and Angola. Thus at the end of 2012, if all this new capacity of LNG was sent to the US it could represent about 15% of all gas supplied to the US market.

Over the longer term there is no strong consensus on LNG imports into the US. Wood Mackenzie projects LNG imports of 16 Bcf/day (5.8 Tcf or 117 mtpa) by 2025. The latest EIA view, however, is that total net imports of liquefied natural gas (LNG) to the United States (in the AEO2008 reference case) will increase from 0.5 trillion cubic feet in 2006 to only 2.8 trillion cubic feet (56 mtpa) in 2030. This is a substantial decrease compared with 4.5 trillion cubic feet (90 mtpa) in 2030 in AEO2007 and implies that some of the LNG already contracted to the US market will be diverted to other markets. It appears to be predicated on softer demand and higher levels of indigenous supply than the 2007 forecast, LNG contracted to the US market certainly can be diverted to alternative markets if sufficient incentive exists (and sufficient extra shipping mobilised). The total quantity is more than enough to make up the Asian shortfall and major diversion would produce some upward impact on Henry Hub price.

Fig. 11 shows the history of regional gas prices and indicates that since 1999 while there has been some general convergence, no region has consistently had the highest prices. Price differentials between regions have been subject to great volatility and it is likely that this pattern will continue.

As noted above, increased LNG imports into the US strengthen the linkage mechanism between natural gas prices in the Asian and North American markets.

At high LNG prices transport costs for long distance deliveries across basins become less significant and on the longer time scale development of new LNG projects will act to reduce major price differences. Qatar alone has committed to produce nearly 50 mtpa of new LNG, aimed, in principle, at the European and North American markets. Qatar recognises the current tightness of the Asian market and has already diverted some of that production on a long term basis to capture a premium. For Qatar such long term diversions have the disadvantage that the supply would then be locked into Asian markets and could not be re-diverted should the price differentials reverse. It is nevertheless likely to continue to seek these opportunities, provided that it can lock in a high price. Otherwise it can always divert cargoes on a spot basis when required. Prolonged high oil prices would in addition, diminish demand growth in Asia while at the same time attracting new supply initially from Asia Pacific producers, but potentially also from the Middle East and possibly Atlantic Basin producers into the Asian market. As the perceived Asian supply and demand balance weakens contract prices will fall, as seen in the period around 2000. This outcome is examined as one of the Scenarios outlined in the next chapter.

If North American gas prices stay low against oil, this will, at the same time, drive up demand for gas in North America at a time when LNG is being diverted to Asian and European markets. Market demand will have to be fulfilled by new, higher cost, pipeline supplies driving higher Henry Hub prices.

Consequently, while large short term gas price differentials may emerge, over the longer term it can be expected that LNG trade flows will act to drive convergence. Because of the different market dependencies on LNG which has led to different pricing mechanisms and contracting practices we do not expect to see full convergence of prices (and our scenarios do not show them) unless a genuine oversupply develops as a result of very weak market conditions. We see this as a very unlikely possibility and that the difference between Asian LNG prices and Henry Hub will not exceed $5/MMBtu (Real) on a sustained basis.

5. Scenarios for the Development of Asia Pacific LNG

5.1 Summary

We have developed three price scenarios against which to analyse the potential for LNG from Alaska. These are not forecasts of the future but present realistic possibilities by which the risks of potential investment in LNG can be assessed.

- Our base (price) case projects a balanced LNG market in Asia where new supply is contracted at a rate to satisfy the market need. There is enough demand in other markets to absorb all available LNG as it comes forward and to avoid aggressive price competition between projects.
- The high case projects firm demand and a shortage of new LNG supply. This is possible in conditions of continuing strong growth, particularly in China keeping demand strong and maintaining high raw material and contracting costs which inhibit LNG development.
- The low case requires weak demand and falling raw material and development costs as a result of recession. Political obstacles to the development of LNG projects are also overcome and supply is plentiful. As a result prices in liquid markets weaken and projects compete aggressively for Asian markets driving prices to uncouple from oil linkage and the world LNG market starts to follow Henry Hub.

We see the base case as by far the most likely of the three as the main Asian markets are very conservative and their structure makes it difficult to generate significant long term shortages or surpluses of LNG. The conditions seen in the high and low cases could arise for periods of time but are unlikely to persist for the full life of the Alaskan LNG supply.

The high case is more likely to be a temporary phenomenon lasting 5 – 10 years before reverting to the central case.

If weak market conditions persisted for long enough to move to Henry Hub linked pricing for LNG, as in our low case throughout the main Asian markets, this would represent a new paradigm and from that point it is most unlikely that prices would ever revert to oil indexation. However it would take a period of weak prices, of the order of a decade, for enough existing contracts to move onto this basis for the shift to become properly established. Shorter periods would lead to some low priced contracts which would eventually revert to something close to our base case.

The cases are described in more detail below.

5.2 Introduction to Scenarios

Because LNG is sold in Asia on long term take or pay contracts to buyers who are, or who directly supply, end users of gas as a statutory or *de facto* monopoly, it is very rare for supply and demand to get out of balance for any length of time. The buyers make their purchasing decisions on the basis of forecast demand (as they have to commit to contracts up to five years before the LNG starts to be delivered). They will not purchase more (or less) than they believe that they need. If there are more projects trying to market LNG than the market needs, the unsuccessful projects will be delayed. Therefore it is very hard for a significant physical imbalance in supply and demand to occur. There will be some downward pressure on price when there is competition to supply but not to the same degree that would occur if there were actual physical oversupply. Clearly buyers sometimes make mistakes in forecasting (for example when the Asian financial crisis erupted in 1997) but these are normally relatively small and can be balanced by the quantity flexibility in the contracts and by spot gas until long term purchases can be adjusted. Otherwise problems are caused by unexpected events such as those with Japanese nuclear power or the premature curtailments of Indonesian supply from Bontang or by unavailability of new LNG projects. By their nature these tend to lead to shortages rather than oversupply. Asia finds itself in this position today.

Over the next two or three years a large quantity of new LNG supplies, mainly from Qatar, are starting up destined for the liquid markets in the UK and US. These should effectively abolish the possibility of physical shortage from Asian markets as sufficient LNG can be diverted to Asia at times of need to cover almost any conceivable shortage. The price paid will have to be high enough to attract the LNG away from the US or UK.

Oversupply is more of a risk in North American and UK markets. These markets are generally assumed to provide a market for any volume (albeit the price may be affected) and do not depend on an end user buyer’s estimate of genuine market need. There is therefore some risk of too many LNG projects committing to supply the US, particularly if demand is depressed by recession, and driving down price (although LNG is still a relatively small proportion of the total US market). In these circumstances there would be a major incentive to divert and remarket LNG into higher price Asian markets and in extreme circumstances this could generate an Asian price linked to US prices.

Our three pricing scenarios are based on these considerations.

5.3 The Asian Supply and Demand Background

The core Asian markets of Japan, Korea and Taiwan between them require around 45mtpa of new LNG supply by 2020. These are the premium markets in the region. Over and above this India and China are expected to add at least another 40 mtpa of new LNG demand. These two markets are more price sensitive. In addition the west coast of North America and newly emerging markets in Singapore, Hong Kong and Thailand are expected to add another 14 mtpa requirement by 2020, making a total of 99 mtpa.

The main uncertainty in the balance is the supply picture (Alaska is not included). There are a large number of potential projects that have announced their intentions to develop and which could potentially supply 160 mtpa of new capacity but most of these have major obstacles to surmount before they become a reality.

LNG projects are notoriously difficult to bring to market but also have distinctly variable histories. To illustrate the point, three major gas discoveries were made in 1971: Arun in Indonesia, North Rankin in North West Australia, and the North Field in Qatar (which becomes South Pars in Iranian waters). Arun delivered its first cargo in 1977, still the most rapid LNG development that has been achieved. The Australian North West Shelf LNG project started up in 1989, and Qatargas in 1997. No Iranian project has yet made its final investment decision. Three other major gas discoveries made in North West Australia at about the same time, Gorgon, Scott Reef and Scarborough which have still not been developed but are seen as active projects. The first suggestion of an LNG project in Nigeria was in the late 1960s and the first deliveries were in 1999. The reasons for the differences are complex and far from exclusively economic. For example, cost was and is a major factor in Australia but politics also played a major part; Australia took a long time to decide whether exports were acceptable. When it had taken the decision the NWS project was held up for some time as demand stagnated in Japan in the recession following the 1979 oil shock, although the Japanese buyers had committed in principle to take the LNG. The licences had been granted to a very small Australian exploration company (Woodside) that had to find partners to be able to fund the development, without totally surrendering its independence. This also took years of negotiation to solve.

Of the 22 identified projects 10 suffer from cost problems, 6 are proposing to try new technology, 6 are being promoted by partners with no LNG experience and 9 are in politically challenging environments. (Some fall into several categories). There is therefore a wide range of uncertainty about the rate at which new supply will come forward.

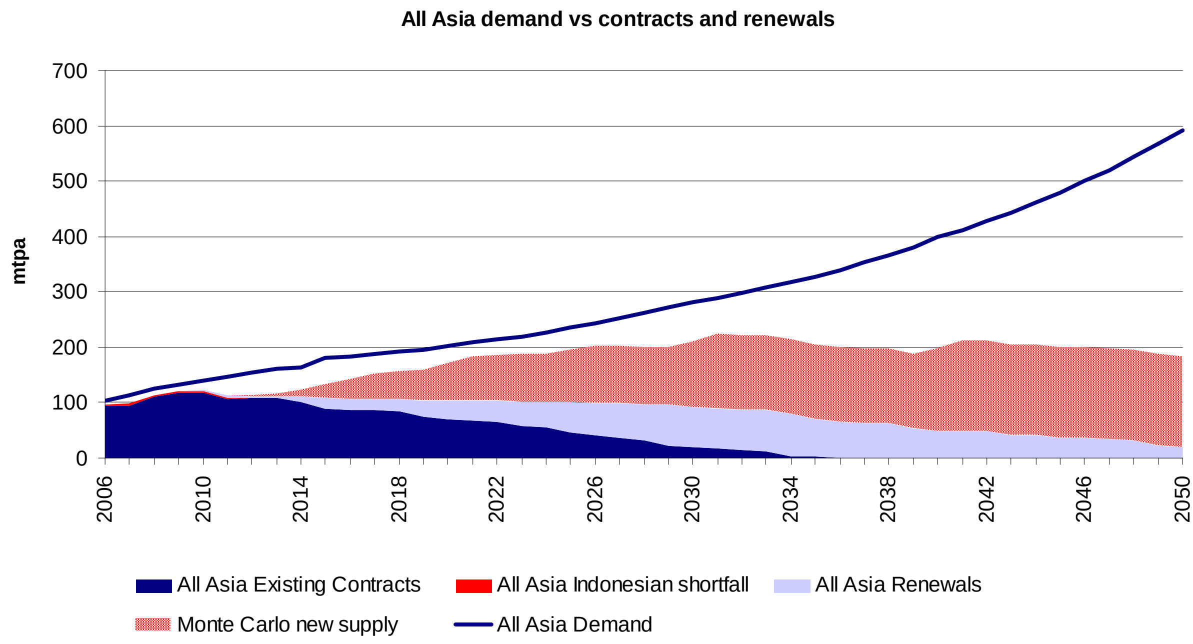
It is therefore challenging to forecast which projects are likely to proceed at a given time. We use a multi-pronged approach based on our understanding of the individual projects. We aim to assess what each project must do to put itself in a position to take its final investment decision, e.g. prove reserves, set up a joint venture structure and agreements, sell LNG, come to agreement with the host country, carry out necessary design work, negotiate finance, acquire shipping etc. as well as achieving satisfactory economics. For our central base case we then make probabilistic estimates of the likely range of start dates for each project and the chance of it not proceeding at all. These estimates are then submitted to a Monte Carlo analysis to achieve a supply profile. This gives some 66 mtpa of new supply by 2020.

To achieve a low supply case we include only those projects we view as “probable” i.e. which are well advanced and have no serious obstacles. These would provide 58.5 mtpa of extra capacity.

For a high case we allow all projects to proceed on their earliest realistic time frame.

The methodology used is set out in more detail in Exhibit A.

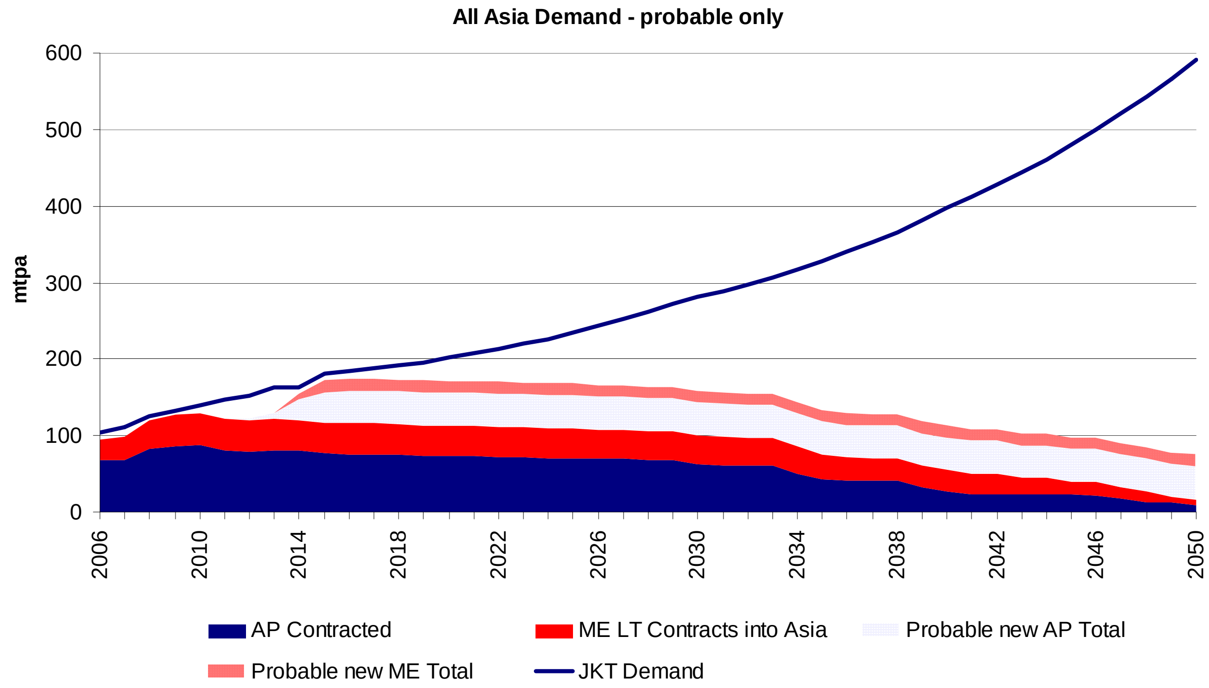
Fig 18 All Asia demand – Monte Carlo supply – base case supply



Source: Gas Strategies Consulting

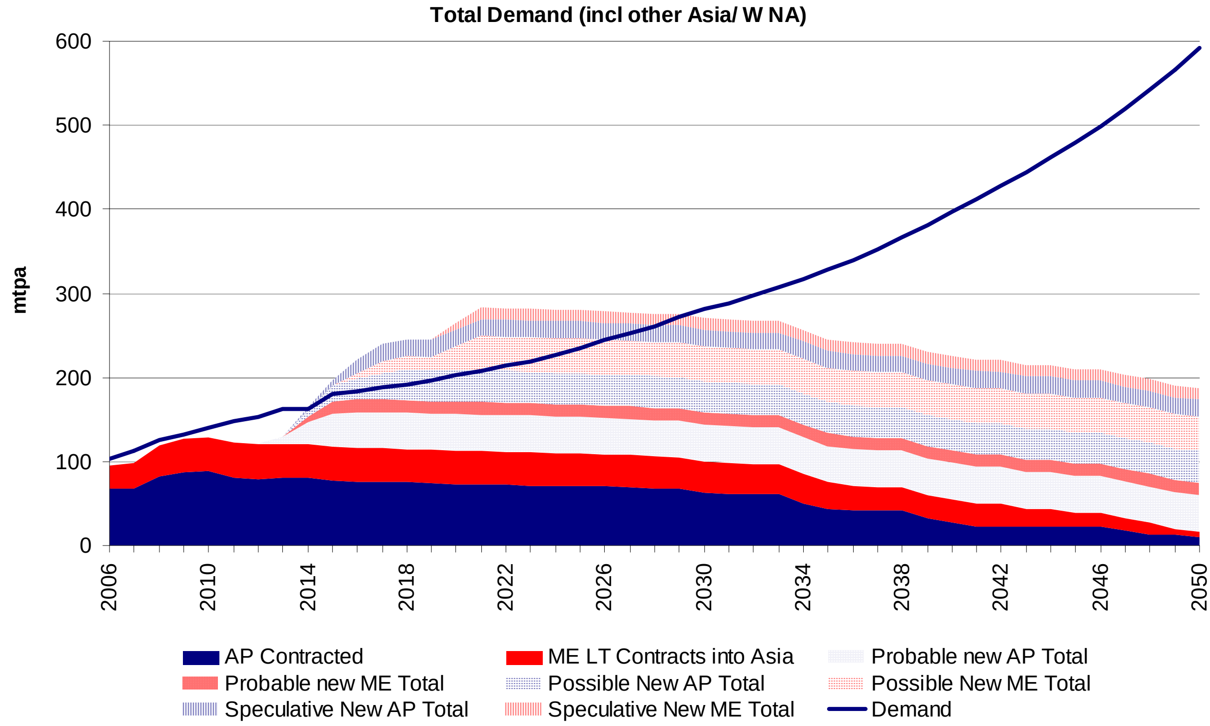
This has a shortfall of around 30 mtpa in the period during which Alaskan LNG would be coming to market, although this is more than covered by available flexible supply that could be diverted from the Atlantic Basin. Nevertheless it represents a plausible opportunity for Alaskan LNG to enter the market at that time.

Fig 19 All Asia demand – Probable only – low case supply



Source: Gas Strategies Consulting

Fig 20 All Asia & W North America demand – all proposed projects – high case supply



Source: Gas Strategies Consulting

The results show that under and over-supply are both eminently plausible. For the reasons set out above, there is a strong tendency towards a balanced market in Asia; projects do not proceed without firm sales contracts.

This is the market context that has driven the generation of our three price scenarios described in the next section.

5.4 Base Case.

In the base case we expect LNG supply to be balanced with demand in Asia, with projects coming forward to meet the market requirement but no more. This balance has prevailed for most of the last 40 years. Generally there have only been just enough LNG projects coming forward to meet market needs and therefore a lack of intense competition between projects. Because projects do not proceed until they have secured long term sales contracts it is difficult for supply and demand to get seriously out of balance for lengthy periods.

This represents a moderate easing of the current very tight market and enable buyers to claw back some of the value currently being taken by sellers.

In the absence of a surplus of LNG, sellers are able to maintain pricing linked to oil. Indeed the buyers prefer to stay with oil indexation being wary of the greater volatility, and especially the extremes of Henry Hub; an index for a market with different drivers from their own.

Because the Japanese buyers are comfortable with the formula that has existed for 20 years we expect the current renegotiations to keep the same linkage to oil and just to remove the "S" curve feature and to make the formula applicable over a much wider range of oil price.

We therefore recommend that the delivered price that should be used for the Alaskan evaluation should be:

$$P = 0.1485\text{Brent} + 0.90$$

Where P is LNG price in $/MMBtu

Brent is Brent crude price in $/bbl

We have looked at the relationship between Brent and JCC over a long period and our view is that they are virtually identical and that it is safe to make this assumption for forecasting purposes.

5.5 High Case

The LNG supply/demand balance has been very tight over the last few years as a result of several factors including unexpectedly strong economic growth driving energy demand, problems with Japanese nuclear reactors, faster than anticipated decline of Indonesian supply, very high costs of liquefaction plant, environmental objections to new projects and social and political challenges in resource holding countries. It is conceivable that these conditions could continue, or at least re-emerge during the period 2012 to 2016 when Alaskan LNG would be coming to market.

Under these circumstances we would expect the marker set by RasGas sales to Kogas in 2006 to become established for long term contracts and therefore that the delivered price should be:

$$P = 0.162 \text{ Brent} + 1.00$$

Spot prices could well go higher as they have over the past two years.

It is unlikely that supply would be as tight as it is at present for a full 20 year period. In practice we would expect the high prices to pull forward enough supply to bring the market back into balance within 5 to 10 years. This therefore represents the upper limit of long term price.

5.6 Low Case

Sustained recession could see slow economic and energy demand growth. On the other hand costs of liquefaction would fall encouraging LNG developers to bring forward projects and compete more intensely for customers. Normally the discipline of contracting on a long term basis with buyers in the end user gas or power markets severely limits the generation of a physical oversupply but the advent of access to liquid markets in the US and North West Europe might encourage seller to believe that they could always place any volume on the spot market. In reality these markets might have difficulty in absorbing the full quantities and there would be downward pressure on prices.

If a surplus of LNG supply did emerge we would expect the US market to be the market of last resort and therefore that it would drive prices in other markets.

Asian buyers in markets that are dependent on LNG would certainly expect to take advantage of the lower prices but would still value security and therefore we would expect them to offer a marginally higher netback price for most of their supply.

Delivered price to a US Gulf port is usually about 90% of Henry Hub price to allow for re-gasification and buyer's margin. Because shipping distance to the US is greater than to Asian markets we would expect to see prices discounted in Asia compared to HH by a freight differential which we would expect to be about $0.50/mmBtu. This is relatively modest and is designed to be able to attract the Middle East and Pacific supplies closest to the US to supply to Asia by offering at least a break even netback. Sellers nearer to the Asian markets would clearly get a better netback and this, therefore takes into account Asian security concerns.

This would give a price of:

$$P = 0.9\ HH - 0.5$$

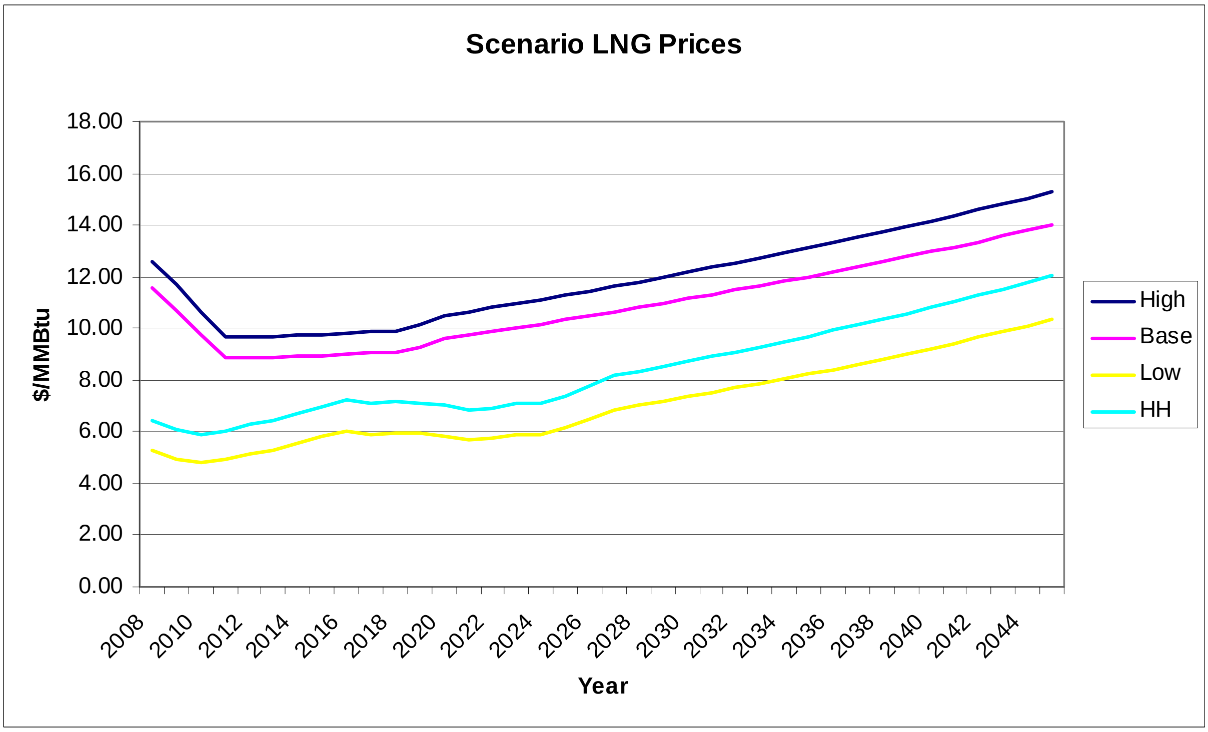
We also view this case an extreme low. To become established it would require a profound period of stagnation in the US and/or Europe similar at least to the problems of Japan post-1990 to generate a prolonged period of surplus supply. Otherwise the extreme conservatism of most of the Asian buyers and the difficulty of revising the existing contracts would be likely to stifle such a radical change.

5.7 Price Lines

In our calculations we have increased the fixed elements in the formulae by inflation in five year increments. This would reflect the mechanism by which inflation would be catered for in the contracts by periodic re-openers.

The prices for LNG delivered to destination ports have been calculated in the three scenarios in Real 2007 terms and are presented in Fig 21.

Fig 21 LNG Prices in the Different Scenarios (Real 2007)



Source: Gas Strategies Consulting/Wood Mackenzie

In the high and base case scenarios LNG prices are significantly above Henry Hub by approximately $4.0/MMBtu and $3.0/MMBtu respectively. The low case scenario on the other hand delivers a price some $2.5/MMBtu below Henry Hub.

(Note: The Wood Mackenzie forecast of Henry Hub prices that we are using is generated on the assumption that Alaskan gas would flow into the North American market. This accounts for the downward kink in HH prices during the 2020s. If Alaskan gas were to be exported as LNG HH prices would be somewhat higher in this period and the difference with LNG price somewhat lower. The alternative forecast of HH without Alaskan gas is not available but the discrepancy is quite small and does not appear critical to the analysis.)

5.8 Shipping Costs

An average voyage distance of 3,900 nautical miles has been selected, which is the far western end of Japan. (China is 4200 to 5000, Korea 3800 – 4200 and Japan 3200 – 3900). This hypothetical destination represents the assumed weighted average of markets in each of which the same ex-ship price will apply.

Shipping costs have been based on the following additional assumptions:

- Q-flex ships are assumed with a capacity of 210,000 m^3 or 4,914,000 MMBtu.
- Charter capital element is estimated as $130,000/day fixed for 20 years

- Operating costs are $17,000/day in 2008 rising with inflation.
- The Valdez port fee for a Q-flex is estimated at $96,236.5 per trip using the port tariff document.
- At the destination port a standard $100,000 per trip is assumed.
- Port charges are assumed to rise with inflation
- Diesel fuel usage is estimated at 216 tonnes per day, with a price linked to the price of crude oil. Diesel was $490/te (Feb 08) when the Brent crude price was $95.04/bbl.

Using February 2008 oil prices shipping costs per MMBtu are then:

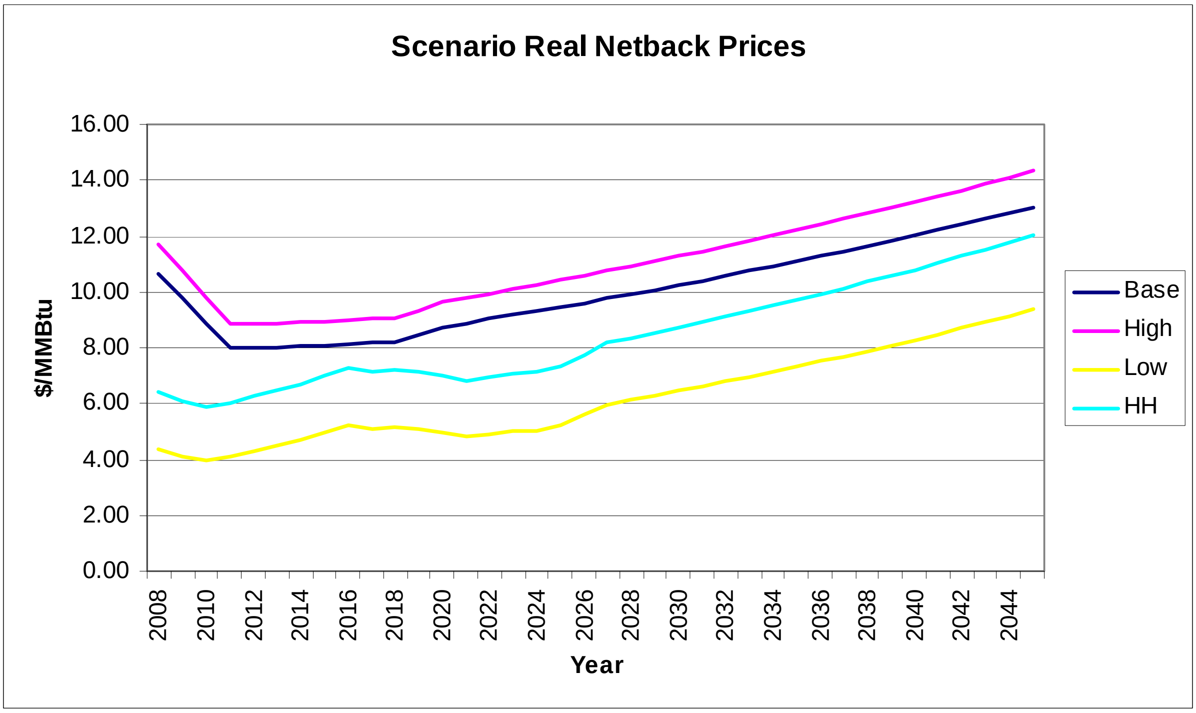
Capital element (fixed)	$0.52	
Opex (inflated)		$0.07
Port Charges (inflated)		$0.04
Fuel cost (oil linked)	$0.36	
Total	**$0.99**	

5.9 Netbacks

Estimated shipping costs have been deducted from the ex-ship prices of LNG to calculate netbacks to Valdez in the three scenarios.

Netbacks for the three scenarios compared to Henry Hub are presented in Fig. 22.

Fig 22 Valdez Netbacks in the Three Scenarios (Real 2007)



Source: Gas Strategies Consulting/WoodMac

These values have been submitted to the team conducting the economic valuation for comparison with the pipeline option.

6. Alaskan LNG Project

The scenarios project the recent experience of the LNG market in Asia Pacific into the future. Overall it is expected that demand for gas, and with it LNG, will continue to grow throughout the evaluation period. It is unlikely though, that the market will remain in one condition throughout. Growth of gas demand will fluctuate, influenced by long term economic and demographic factors and by short term events. Similarly the availability of LNG will vary over time, again affected by technology and economics but also by political decisions and events.

6.1 Price and Volume Risk

The approaches and requirements for structuring and financing LNG projects are discussed in sections 7 and 8. Fundamentally there is are requirement for all elements of the chain, gas supply, liquefaction capacity, shipping, re-gasification capacity, market access and credit-worthy customers to be secured at the time the commitment invest in the project is made. Importantly there needs to be a long term take or pay sales contract. LNG projects cannot be financed on the back of the short term LNG market.

The critical period for an LNG project therefore is the period 4 -5 years ahead of the start date. During this period the design engineering is being completed and construction contracts being agreed. Also, the long term sales contracts are being finalised in which the ramp up of offtake and the flexibility of lifting and destination are determined and the price is fixed. The conditions prevailing in the market at that time will play a major part in fixing value and the scenarios portray how they might arise with the impact on price that represents a major risk factor for the project.

Overall the LNG price and netbacks estimated in our scenarios do not diverge widely from Henry Hub suggesting LNG will not enjoy a large economic advantage over the pipeline option. This relationship is based on the projected values for crude oil prices and Henry Hub and will hold unless there is a major reduction of Henry Hub in relation to crude oil which is not anticipated.

In reality, as indicated in Fig. 11 it is likely the differences between regional prices will vary over time meaning Asian LNG would enjoy periods of advantage and disadvantage in relation to North American pipeline gas.

Take or pay contacts will provide strong mitigation against volume risk, ensuring cash flow for the project in the event end-user market demand is weak.

The approach with LNG projects contrasts with that for a pipeline feeding the North American market. In this case the depth and liquidity of the market are such that provided the pipeline delivers the gas to a major trading centre, it can be assumed there will be a market for the gas. In these circumstances there is no need to have secured long term take or pay contracts prior to committing to develop and transport the gas. It is sufficient simply to take a view on the quality of the market and outlook for prices.

6.2 Project Phasing

Different options can be considered for the development of Alaskan LNG. The base case development plan, paralleling that for the pipeline converts 4.5 Bcf per day to LNG with start-up in 2020. The quantity of gas will yield nearly 29 mtpa of LNG posing a major challenge for the project.

The Asia Pacific region today consumes about 100 mtpa and although it is growing, by 2015 29 mtpa will still represent almost 20% of total market demand. The market will be growing about 7 mtpa per year so the Alaskan production on its own would account for 4 years of market growth. Start up of the project would need to be phased over this period assuming Alaska won all the contracts for new demand. In reality other projects will be competing to supply the market, while some contracts will be coming up for renewal, allowing Alaska to compete and potentially displace them. Ramp up to full production based on Asian contracts alone could therefore take nearer 8 to 10 years.

There are precedents for growth of LNG production of this scale. Qatar has embarked on a colossal growth of its production capacity which is set to rise by 60.1 mtpa over a 7 year period from 2004 to 2010. Qatar however has been able to anchor its prodigious growth by accessing the liquid markets of USA and UK allowing it then to contract sales into the Asian market at a gentler pace. Use of these liquid markets has also been important not only to enable rapid growth of total capacity but also to maintain the economics for each train. The project has achieved economies of scale by utilising 7.8 mtpa trains. Obtaining contracts for the offtake of all this production from start-up is difficult. Taking production not locked into a market to USA or UK enables the train to operate close to capacity from start-up which is critical for project economics.

The Sakhalin project in the Asia Pacific region plans to start production from its two 4.8 mtpa trains in 2008/9. At 9.6 mtpa this is the largest LNG project so far to anchor itself in the traditional Asian markets. Its sales are understood to be scheduled to take five years from start up to ramp up to full contract quantities. In order to match offtake with contracted demand from Asian buyers, the project has accessed the North American market through the re-gasification terminal at Costa Azul in Baja California. A minimum quantity is locked into that market on a long term basis while the remainder can be diverted back to Asian customers as their demand ramps up.

Alaska, like Sakhalin suffers the geographical disadvantage of its long distance by sea from the Atlantic Basin markets and particularly the Gulf coast of USA. Consequently it must look to the west coast of North America for a liquid market outlet. This has several difficulties. Unfortunately re-gasification capacity is very limited, owing to the strong opposition of communities, and the market is smaller and more isolated with the result that local basis can be depressed more readily than in the Gulf by a large influx of LNG. Any terminal in the US itself would require the use of Jones Act shipping, which is likely to increase costs substantially. Nevertheless Alaskan LNG will probably need access to Costa Azul or another new terminal for some short term deliveries (4 – 5 mtpa would be a realistic maximum quantity; 30 mtpa exceeds both the likely terminal capacity and the ability of the Californian market to absorb the quantity) while building long term contracted sales to Asia markets. Even so to build production capacity up to 30 mtpa is likely to take 10 years.

Having access to an alternative market would also be important in negotiations. Buyers will be aware of the sellers' ambition to develop a large quantity of LNG for which the logical market is east Asia. This fact alone will encourage buyers to view Alaska as a "captive" supply and hold out for a lower price. The level of competition will determine how successful this could be for buyers but this could lead to the Henry Hub based prices of the low case scenario.

6.3 Quality

The target markets in Asia require gas of high calorific value (Table 2) such that it would not be necessary to extract NGLs from the gas stream in order to serve them. Although the buyers will take short term cargoes of low calorific value and make them acceptable by adding propane, they will probably not commit to long term contracted supply on this basis. If they were to they would require a significant discount.

The difference in quality between the Asian and North American markets creates a constraint for Alaskan LNG to be switched from one market to the other, which is likely to be required as described above. This problem can however be relatively easily overcome by introduction of nitrogen at the North American re-gasification terminal to reduce calorific value. Such facilities are in place at Costa Azul and other terminals in USA.

7. Structuring and Financing the LNG Project

7.1 Requirements of AGIA

Under AGIA a new project for transport and processing of gas from the North Slope to market is required to offer open access, with new capacity being paid out through a rolled-in tariff for all users.

These principles are commonly applied in pipeline transportation projects where, through an open season, gas shippers can secure capacity on a long term contract basis. The open season process, where potential users bid for capacity, ensures firstly that the pipeline is required and can be built, secure in the knowledge on the one hand that the capacity will be used and on the other that it will be built. The pipeline can therefore be sized and built by a third party transporter to accommodate all those willing to commit gas for transport under the terms of the tariff. Longer term expansions of capacity if new gas is discovered can be made allowing it to be brought to market while avoiding the risk that high costs will create an economic disincentive for the marginal producer so delaying resource development.

In the case of LNG it would be very difficult to organise a meaningful open season. Potential users would need to be able to bid for a package of LNG plant capacity and gas treatment plant and pipeline capacity; the two could not realistically be separated as capacity in one would be of no use without capacity in the other. However, any bid to use the capacity would have to be conditional on the users access to gas and its ability to market LNG at a price that would justify the tariff. On the owner' side there could be no assurance that the capacity would be built subject to sufficient successful bids being received, partly because the costs would be very uncertain at that stage and partly because none of the users is yet ready to make a firm commitment to capacity. These conditionalities seriously compromise the bidding process and mean that the bidding would at best be the first step in a longer negotiation. It also introduces a risk of opportunistic bids, where a party with no real interest in physical capacity makes a speculative bid in the hope of being able to onsell it to a genuine user. Such a speculative bidder has very little downside risk as the conditionality means that it cannot be held to its bid.

Such an approach in which a third party company, with no involvement in the upstream, has built and operated a liquefaction plant has in consequence, never been adopted for the development of LNG. The challenges faced by companies when developing LNG projects drives a need for major upstream producers to participate in the liquefaction project and beyond. LNG plants have invariably been built by parties with a major interest in the upstream gas supply. This does not mean that LNG projects cannot be structured to encourage exploration and development and in a way which is compatible with AGIA. Indeed the general experience of LNG projects wherever they have been constructed is that by demonstrating a route to market upstream exploration has benefited. There are examples where authorities have actively and successfully sought to promote exploration by the way the LNG project has been structured. In the following section the different approaches adopted for structuring LNG projects are outlined and models that might meet Alaska's needs suggested.

7.2 LNG Project Structures and Drivers

The principal motivation for investment in LNG has traditionally been for the owners of gas to monetise their resources that could not be connected to markets by pipeline. The capital costs and technical risks of building liquefaction plants have in turn imposed requirements for large scale, and hence very large capital investments, and also for long term security of gas supply and off-take to provide assurance of financial returns. Off-takes and revenue streams have been obtained by negotiating long term (20 year plus) sales agreements with take or pay provisions. For such an agreement to be secure the buyers needs to be a credit-worthy entity with access to a market in which the gas can be placed. Secure access necessitates capacity in a re-gasification terminal connected to the market and ownership, or at least long term control of LNG carriers.

Over the history of the LNG industry the technical risks associated with building and operating liquefaction plants, ships and re-gasification facilities have diminished as experience and technical developments have proceeded. The trend of declining unit costs of liquefaction which endured from the early 1990s to around 2002 has however, been reversed in recent years with high demand on engineering contractors and soaring commodity prices. Consequently LNG still represents a very major investment which must be carefully structured commercially to minimise risks.

The challenge for LNG developers continues to be to have confidence, underpinned by contracts, in the supply of gas and its cost, the construction of the liquefaction facilities, the availability of ships, access to re-gasification capacity, sound markets and credit-worthy buyers. Bringing these elements together to enable the investments and contractual commitments along the chain to be sanctioned simultaneously demands dedicated resources over long periods and unity of purpose by the proponents.

Because of their scale it is usual for LNG projects to involve multiple participants. This arises from the need to access large gas reserves (over 5 tcf of gas are required for a 5 mtpa train to operate for 25 years). Such reserves are seldom the property of one company, not least because in many countries a state entity will be present. In addition the scale of investments often brings several companies together to spread the financial risk.

The presence of multiple participants bring some alignment it also presents a challenge as individual oil and gas companies may have differing objectives (e.g. investment priorities, target markets). International and national (or state) companies will almost certainly have different perspectives (e.g. with regard to the attractiveness of export or national markets. Divergence of views can be the cause major delay or failure of LNG projects (e.g. Angola LNG, the Cristobal Colon project in Venezuela).

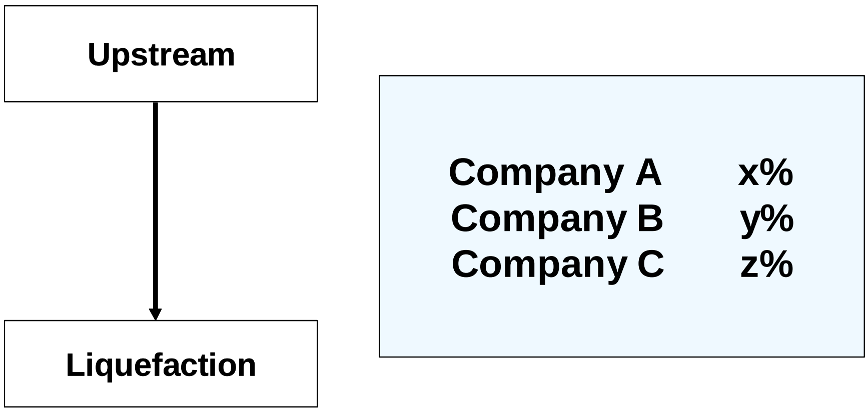
Over the course of the development of the LNG industry participants have pursued several different business models to structure LNG projects. Essentially however they have been variants of two fundamental types; liquefaction as a profit centre and liquefaction tolling.

7.3 Liquefaction as a Profit Centre

The concern to monetise gas on one hand and to secure gas supply on the other has led to most liquefaction projects being developed by the gas resource owners. The technical risks and financial commitment can only be carried by large financially robust companies: the result is that the oil and gas majors, along with state companies have led the development of the world's LNG projects, with ownership of the liquefaction plants reflecting ownership of the gas resources. Similar levels of participation in gas resources and in liquefaction facilities provide strong alignment between the parties with investments broadly in proportion to the ownership of gas supply.

It is relatively rare however for the upstream assets, pipelines and the liquefaction facility to be part of a single integrated project Fig 23 (as is the case for the initial RasGas project in Qatar and for the Sakhalin II LNG project in Russia).

Fig 23 Integrated Upstream and Liquefaction

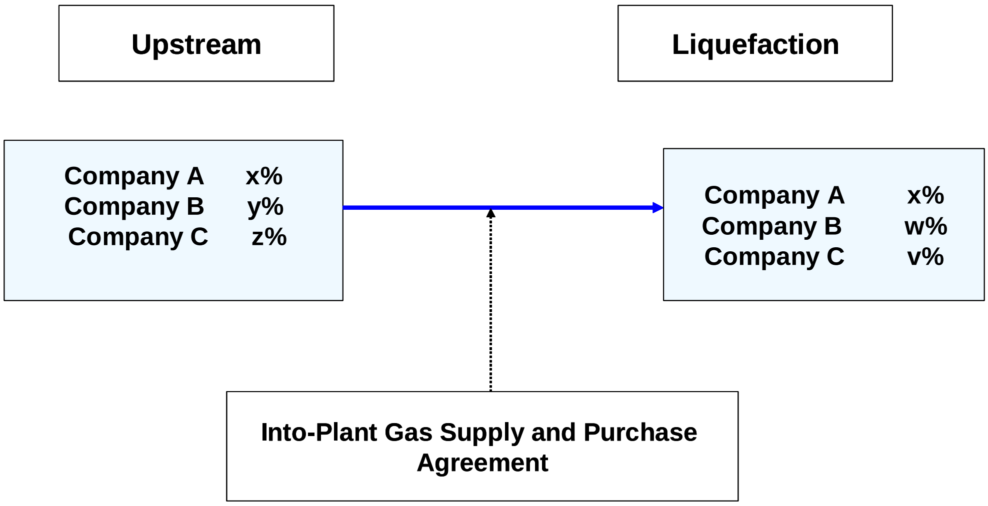


Source: Gas Strategies Consulting

In general the ownerships of upstream assets and the liquefaction plant are separated in different legal entities. This is driven by the differing legal and tax regimes that apply to hydrocarbon production and processing and allow each to be addressed separately and ownerships varied which can have benefits for taxation and financing.

Typically the upstream production in a field is an unincorporated joint venture in either a tax and royalty or Production Sharing Contract (PSC) regime with participants having rights to individual shares of the gas stream. The liquefaction plant on the other hand is an incorporated joint venture buying gas from the individual companies for manufacture and sale of LNG (Fig 24). The participants earn value through the dividend stream of the company.

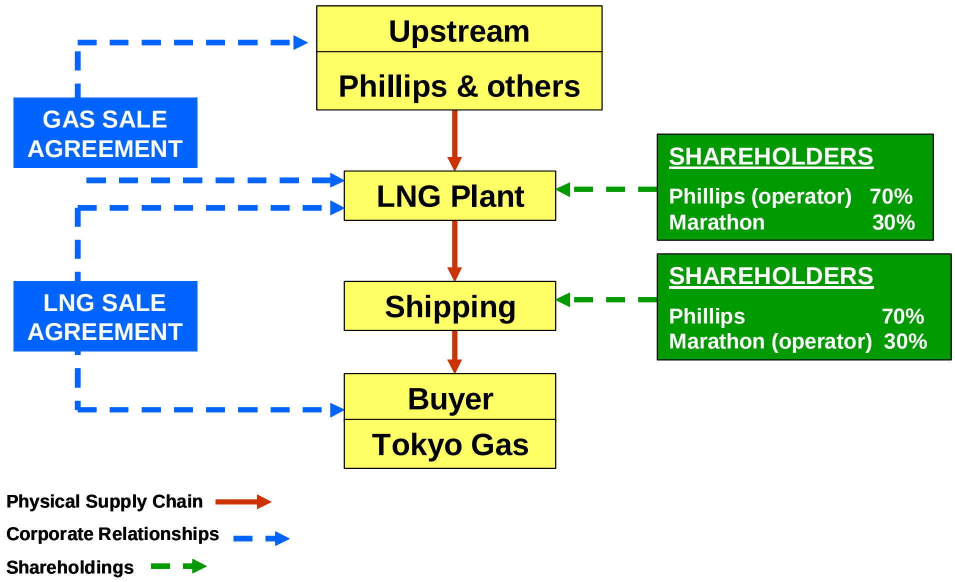
Fig 24 Liquefaction as a Separate Profit Centre



Source: Gas Strategies Consulting

The traditional extension of this model is for the liquefaction company also to own the fleet of LNG carriers used to deliver the production of the liquefaction plant. Ownership is either through the liquefaction company directly or a separate, wholly owned, company. Occasionally the ships are owned by a third party company but chartered on a long term basis to the liquefaction company. These arrangements provide control over deliveries and destinations for the liquefaction company and the ability to price cargoes according to the market of delivery. This is the business model that was used in structuring the existing Alaskan LNG project at Kenai (Fig 25).

Fig 25 Kenai Project Structure



Source: Gas Strategies Consulting

The liquefaction company will sell its production on a long term basis to customers who will be responsible for selling the LNG in downstream markets. It is traditional, especially in the Asia Pacific market for customers to own the re-gasification facilities with deliveries being made by the liquefaction company.

Originally, customers making commitments to long term supply also sought first refusal on any production excess to their requirements. Latterly this strict linkage has weakened with such excess being sold to other customers on a spot or short term basis.

In addition, some liquefaction companies have sold on an FOB basis to buyers with their own shipping fleets. This removes the burden of financing and operating ships but transfers the control of delivery destination to the buyer, making specific market-related pricing more difficult for the seller.

In a further development, as markets have opened to competition in gas supply, some owners of liquefaction facilities have moved down the LNG chain, acquiring capacity in re-gasification terminals and selling gas wholesale into the markets. This has enabled them to exercise even greater control over their production and to optimise value through direction of cargoes to the markets offering the highest netbacks. Companies such as BG, BP, Shell and Total now have their own ships and re-gasification capacity and are buyers of LNG, usually, but not always from liquefaction plants in which they are also participants. In a similar vein, ExxonMobil and Qatar Petroleum have control of re-gasification capacity in USA and UK and retain flexibility over the market destination enabling them to divert cargoes to capture value in the Asia Pacific market. Sonatrach has market access in UK and USA for its Algerian production.

To an extent these companies are providing the credit-worthy buyers required to justify the upstream and liquefaction investments. Their risk is however, mitigated by ownership of re-gasification capacity and access to liquid markets where volume risk, if not price risk, is regarded as low.

The pipelines and other infrastructure connecting upstream production to the liquefaction facilities will usually be owned by the same parties with the confidence that risks to the gas supply are minimised. In general LNG project proponents have resisted third party access requirements on the pipeline to the liquefaction plant. Accepting this stipulation would expose them to the risks either of failing to have their own gas delivered to liquefaction, or of having to invest in pipeline or liquefaction capacity for the third party and earn a low rate of return for the service.

Under these circumstances project proponents have preferred either to have third party gas sit behind their own in priority, potentially delaying its production many years, or the gas can be purchased at low cost providing an attractive economic return for the liquefaction project (but possibly unattractive for the producer).

7.4 Tolling Liquefaction

While having the liquefaction project and upstream fully integrated, or the liquefaction project as a separate profit centre, provides control for the participants and a robust structure for financing, it has presented particular problems for expansions.

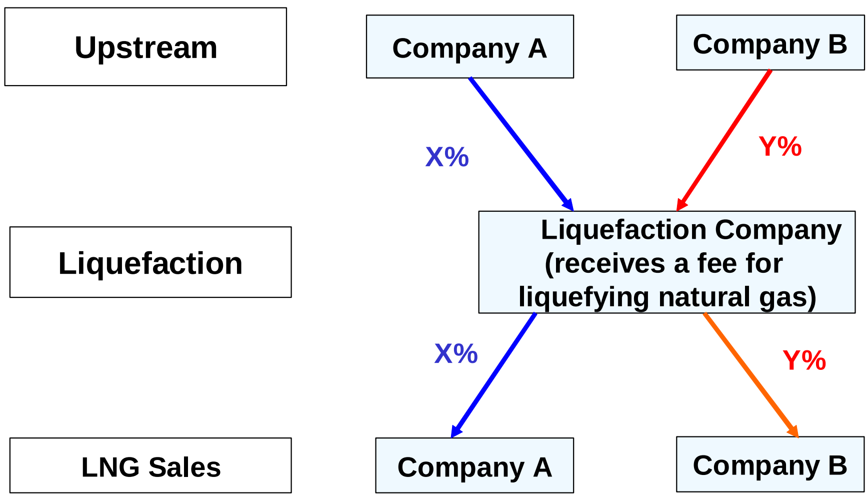
Having an established equity structure makes it easy to expand capacity through injections of additional equity or from the cash flow of existing production, provided the gas supply continues to come from the participants' upstream production in similar proportions.

Difficulties emerge when gas supply comes from new reserves with different owners. The suite of agreements between the JV partners and frequently the state, with specific tax treatments for the liquefaction plant, is usually the result of lengthy negotiations and value trading. There will therefore, be great reluctance by at least some of the parties to reopen these agreements in order to bring in a new participant, especially if doing so leads to the dilution of the existing partners' shares. Reopening the agreements will bring old issues back onto the table with the risk of loss of value for someone.

The solution, as discussed above is usually to offer to buy the gas with the existing partners investing to expand production. If the liquefaction plant operates as a profit centre, the gas supplier will be reluctant to sell as they will be excluded from much of the value their gas will earn. If gas quantities are small an accommodation can usually be found, but if they are large the result can be delay in exploitation of the gas resource, a problem both for the resource holding company and for the state for which income, and also inward investment and jobs are deferred. Ultimately a new liquefaction venture can be justified with different shareholders operating on a new site. The proliferation of liquefaction ventures in Nigeria and Qatar is a symptom of this problem.

Where the potential is recognised of new gas suppliers emerging over time governments have required a different approach that avoids these problems through the establishment of tolling liquefaction (Fig 26). Companies have also sought this solution recognising it can provide greater flexibility in exploiting gas reserves and also open the way to controlling their share of the LNG stream.

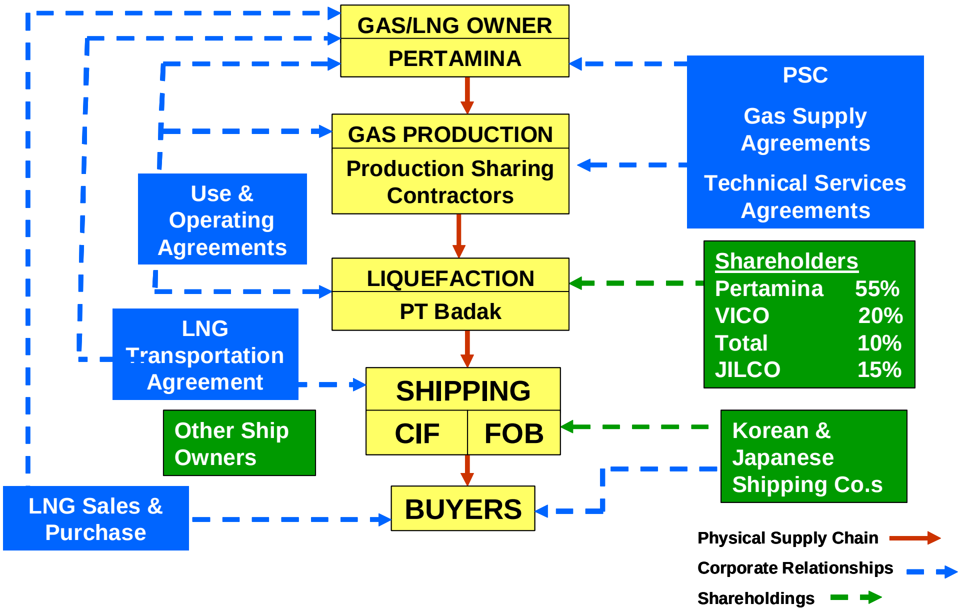
Fig 26 Tolling Liquefaction



Source: Gas Strategies Consulting

A quasi-tolling structure was first implemented in the Bontang project in Indonesia. In reality the state oil and gas company Pertamina owns the liquefaction plant and the LNG which is sold but it has the same result as tolling for the upstream PSCs (Fig 27).

Fig 27 Indonesia Bontang Project Structure

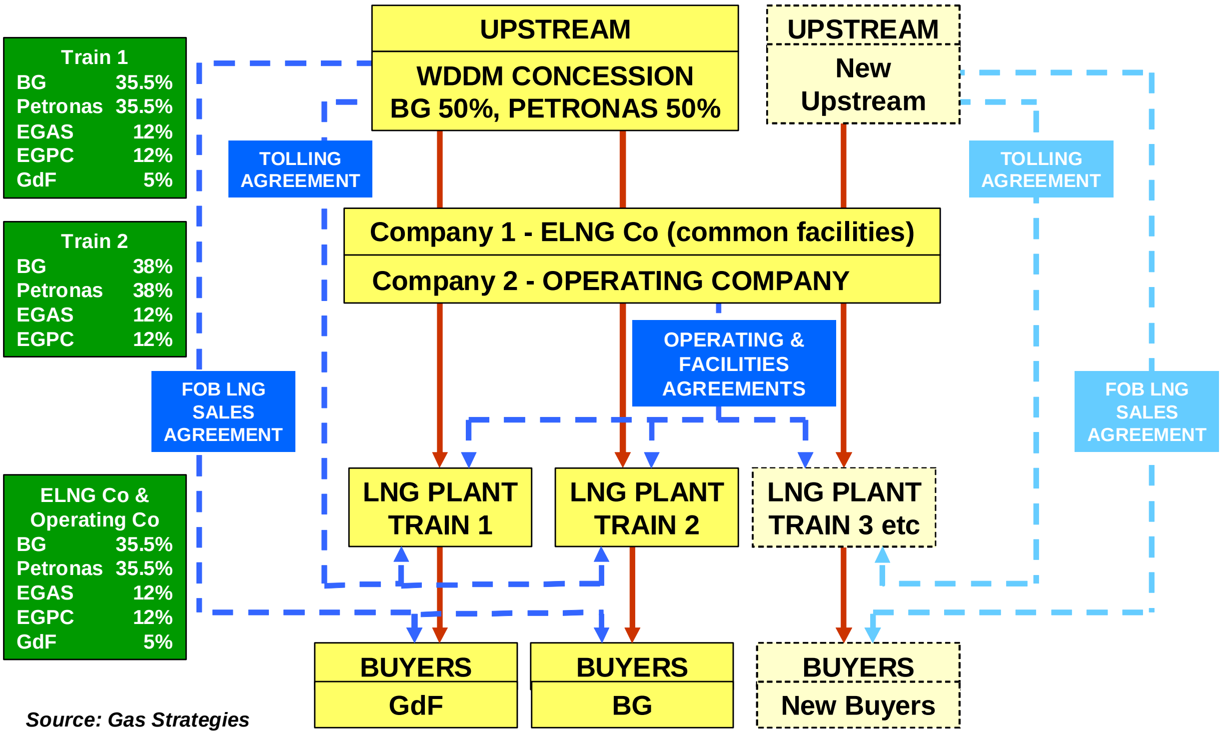


Source: Gas Strategies Consulting

This basic approach has been replicated in Trinidad and Egypt (Fig 28). A company is established which builds and operates the liquefaction plant producing LNG on behalf of the gas suppliers. The company carries the construction and operation risk of the plant but does not carry the risk of demand and prices in the LNG markets. The gas owners retain ownership of the LNG which they then sell. Consequently, the fee charged by the facility is one that delivers a modest return to the owners while the profits from the sale of LNG pass back to the upstream. Clearly the tolling company must demonstrate its technical competence and have sufficient financial capacity and it will initially be created with the involvement of one or more of the major oil and gas companies that provide gas to the first facility. Unless the owners of the plant have an interest in the production of LNG it is difficult to persuade them to invest in a low return facility (even if it is low risk).

The investment in the tolling facility is secured through long term toll-or-pay gas processing contracts with the gas owners. The owners in turn secure their commitments with long term take or pay contracts with gas purchasers. In Bontang Pertamina owns and sells all the gas (though with the participation of the individual PSC holders in the negotiations). In a true tolling arrangement the gas owners are able to take their LNG and market independently. This freedom of action is attractive avoiding the need for gas producers who may have differing portfolios and strategies to act completely in unison.

Fig 28 Egypt LNG Project Structure



Source: Gas Strategies Consulting

When new gas supplies become available the tolling company is able to expand its facilities based on long term tolling commitments from the new suppliers. The facility can be built on the same site as the original and share in the cost benefits that brings.

The tolling liquefaction structure provides a form of open access with new suppliers able to monetise their gas more easily and/or more profitably than with a profit centre model. If the tolling facility also offers a bundled service of pipeline transport to the liquefaction plant this can assist the upstream producer in securing all elements of the chain prior to taking FID. If however the pipeline is owned by an independent third party operating an open access regime then the same difficulties apply as with the liquefaction profit centre model i.e. the producer cannot commit to the pipeline capacity before securing liquefaction capacity and sales and the latter are difficult if pipeline capacity is at risk. Faced with this challenge the producer will more likely prefer negotiated access with the pipeline owner or to build their own dedicated pipeline.

8. Financing LNG Projects

8.1 Equity Financing

A significant number of LNG projects are equity financed. For the major oil companies, Japanese trading houses and some national oil companies with strong credit ratings, equity finance is the preferred route. Not only is it lower cost but also is quicker, has a significantly reduced administrative burden and permits a more innovative approach. It may be the only available route where credit risk in the originating country is too high. Examples of equity financed project are the three Malaysian projects, Australian North West Shelf expansions and the new, high cost, Pluto project, Sakhalin (although it is seeking finance after taking FID), Nigeria and Angola.

The third Malaysian project MLNG Tiga is a particularly interesting case. Its sponsors are Petronas, the state oil company; Shell, Mitsui and Mitsubishi; none of whom needed to raise project finance. The project took its final investment decision in 2000 at a time when the Asian markets were very weak. As a consequence it only had firm sales contracts for a very small proportion of its output. Nevertheless Petronas particularly, was prepared to take the risk of investing in the hope that it could get ahead of other projects that were also trying to secure market at the time such as Sakhalin and Tangguh. In the event the strategy was reasonably successful as Tiga started up in 2003 not long before the markets went short of supply and sales volumes quickly built up to cover the full capacity. No other project has been prepared to take a risk of this magnitude and it would certainly not have been possible if the project had required external bank financing.

8.2 Limited Recourse Financing

The majority of LNG projects, particularly where smaller companies are partners in the project require limited recourse financing. This has costs, in fees and higher interest rates, but also in time and administrative burden. Project financing will add 6 months to a year to the schedule prior to taking FID and will require considerable effort in providing information to the banks who do extensive due diligence on all aspects of the project. The banks will closely scrutinise the reserves, markets and pricing, credit-worthiness of buyers, access to essential infrastructure (such as pipelines and terminals), engineering, shipping, environmental, insurance, government agreements etc.

Banks still expect to see long term take-or-pay contracts securing LNG sales and the amount they will lend is based on take-or-pay volumes. Recently projects have been attempting to get banks to give some recognition of potential spot volumes but without any success so far.

For sales into liquid markets such as the US or UK long term contracts are still needed mainly because the banks require evidence that the buyers have long term access to receiving terminals and downstream pipeline capacity. They are however more relaxed with regard to market volume risk as market liquidity means the LNG can be accommodated.

Banks also require evidence that sufficient reserves of proven gas are dedicated to the project to fulfil the sales contracts (a reserves certificate from a recognised independent consultant and a gas supply contract that is back-to back with the LNG sales commitments). If a third party pipeline is used to get gas from reservoir to plant a long term ship-or-pay transport contract will be expected.

For a period in the late 1990s it was quite possible for a project to raise sufficient finance without having sold its full capacity. This was because investment costs had been reduced considerably but, in spite of tight market conditions, price had not fallen to the same degree. However, costs have now risen sharply and it is very doubtful if a project could obtain sufficient finance without selling very close to full capacity.

The finance community is comfortable with the pricing regimes in all the major markets but will take a conservative view of the level of oil price and will need to understand and endorse forecasts of e.g. Henry Hub prices.

Provided that the sponsors and EPC contractors are credible and experienced it is normally possible to persuade the banks to accept modern technology. However, they normally insist on lump-sum turn-key EPC contracts with established contractors.

Regardless of the scrutiny of the engineering arrangements banks do not take completion risk. The sponsors are required to guarantee repayment until the plant has commissioned and is operating satisfactorily. Only after a detailed completion test has been satisfied will recourse be limited to the project cash flow.

Maximum tenure of the loans is normally 12 years from start up. There is a moratorium on repayment until start up.

8.3 Bond Finance

There are times when the bond market may offer an attractive alternative to limited recourse financing. In practice only the original two trains of RasGas in Qatar has raised significant quantities of bond finance. The requirement for security and the level of due diligence is similar to limited recourse financing with the added complication that the bonds have to be rated by a credit rating agency. To be of interest they must have an investment grade rating.

Repayment is rather less flexible than limited recourse financing as interest has to be paid immediately on issue of the bonds. However, the term may well be longer than loan finance.

9. Risks in Structuring Alaskan LNG

9.1 Upstream Company Perspective

The companies holding reserves on the North Slope (principally ExxonMobil, BP, ConocoPhillips) seek a means to bring their gas to market profitably. Their preference between a pipeline and LNG will be based on economic evaluation, assessment of the risks and the fit of the two schemes with their broader strategies.

Each of the companies has large interests and portfolios in North America and is well experienced in transportation, marketing and trading so the risks of commercialising their gas are well understood. Significantly the liquidity of the North American market means that there can be confidence that the gas will be sold. The chief concerns will be the price that can be obtained and the costs of getting gas to market. Use of a third-party interstate pipeline is commonplace in North America and does not present undue technical or commercial risks. In addition through the open season process they will be confident of securing long term transportation rights. Under these circumstances the chief concerns are likely to centre on the level and stability of upstream tax and royalty in the State of Alaska.

The development of an LNG scheme presents a different picture.

As discussed above, because of the complexity of the commercial arrangements and need to manage risk along the chain there will be a great reluctance on the part of the upstream companies to commit gas to a liquefaction plant to be built and operated by a third party. If LNG is to be successfully developed at least some of the companies will need to be encouraged to participate in the liquefaction project. If one of these companies does agree to participate it is likely all three will decide to do so.

Experience around the world is that when so many large companies do join together the negotiations between them will be lengthy, not least deciding the structure of the liquefaction venture and the individual shareholdings. In the case of Alaska, as the reserves in Prudhoe Bay are well characterised and the companies used to working together, negotiating the LNG project may go smoothly.

Beyond that however, the companies will face two key challenges. Firstly, the Asian markets for gas are not open and competitive. Long term customers will need to be secured and sales contracts negotiated. It will need to be decided whether the companies will market their gas separately, and therefore competing with each other for the large credit-worthy customers, or if they will form a joint company to market and sell together. Whichever way they go their ability to secure sales will be influenced by the market conditions prevailing. As discussed in the description of the Scenarios, the conditions facing the sellers could differ markedly, affecting not only the contract price but also the time taken to secure the contracts.

Secondly, each of the companies has gas reserves in the wider Pacific and Middle East region, much of which it will plan to develop as LNG and consequently each will have a different strategic perspective on how Alaska gas fits in their portfolio, and the priority is should receive in their marketing efforts and allocation of capital. The risk is that at least one of the companies will place Alaskan LNG on lower priority and slow its development.

In the assessments by the companies all these considerations will contribute to a heightened risk of major project delay. Also apart from the capital costs of the projects, the companies will see very significant additional costs of the LNG route in commercial negotiations with each other, with their customers and with their contractors.

Looking at the wider strategic picture also, the companies will be aware of the Federal desire to have Alaskan gas contribute to the energy security of the USA. Protecting their wider US interests may drive a reluctance to be seen to be promoting gas export from Alaska.

Overall therefore, in the absence of an overwhelmingly strong economic case, which has not been demonstrated in our analysis, it is understandable that the reserve-holding companies will express a preference for the pipeline option.

9.2 State of Alaska Perspective

9.2.1 Open Access

It is essential from the State of Alaska's point of view that the development of North Slope gas encourages continued exploration and development. For this to happen, the explorers must have confidence they will be able to commercialise discoveries in a timely manner. Confidence will be driven by stability of the fiscal regime in which they operate and by the knowledge that new gas discoveries can be commercialised in a timely manner. Importantly the existing users (the Prudhoe Bay operators) should not be in a position to control the system holding back proven third party gas in order later to bring forward their own less mature resources.

As discussed, for LNG to be successful the upstream companies will need to participate in the liquefaction project, and also possibly the associated supply pipeline. Allowing this to happen however, need not result in those companies controlling access to liquefaction. It must be recognised that third party access in liquefaction differs from that of a pipeline. In the latter capacity can be added in smaller discrete quantities through compression upgrades and looping. This ability provides the pipeline owner with a cost advantage over a new-build competitor, reinforcing a natural monopoly position. Under the terms of open access new shippers can be accommodated as they come forward. The capacity of liquefaction plants is only expanded through the addition of a complete new train, requiring the commitment of major new resources (of the order of 5-10 Tcf). Once a train has been built and the capacity committed to suppliers for 20 years or more, if other producers could justify it, a further train would need to be constructed to accommodate their gas.

Examples exist where the flexibility to accommodate third party reserves has been provided. In the Bontang project in Indonesia the addition of new trains was controlled by the state. When sufficient market demand was identified to justify a new train upstream companies were allocated a share of the supply, and the proceeds from LNG sale, based on their level of proven reserves at a given date. The approach provided an incentive for exploration and appraisal.

In practice the requirement would be that the company constructing the LNG project should establish a separate management company to operate the site and be required to provide services to any new train to be built. The site should operate on an open access principle allowing different companies to invest in and own the capacity of additional trains supplied with their gas. The significant cost benefits of building an expansion train on an existing site would be shared with all site users (analogous to a rolled-in tariff) through the management company tariff. The supply pipeline would also be owned by the management company with expansions of its capacity coordinated with those for liquefaction. A key feature of this approach is that is avoids companies being required to invest in building liquefaction capacity for third parties with a utility rate of return, which would be resisted. It also allows upstream companies to manage the progress of their projects, seeing the integrated chain. Each train can operate as either a profit centre or tolling plant, within an overall tolling structure for site management.

In order to prevent companies taking blocking positions it would be a requirement to demonstrate the availability of proven gas reserves and real progress in advancing their project without which their claim on the new capacity would be forfeit.

This arrangement would meet the requirements for project financing and most closely would resemble that of the Egypt LNG project discussed above which appears the best starting point for Alaska.

9.2.2 Taxation

While from the companies' standpoint there would be reluctance to pursue LNG, should the economic justification be sufficient a route can be seen which would meet the State's objectives with respect to third party access but other challenges would remain.

The State will be interested to receive tax remuneration based on the value generated by the LNG which will depend on the market to which the gas is delivered. Companies may choose to sell LNG to an affiliate FOB at the liquefaction terminal with the buyer then able to exercise destination flexibility and optimise value. Unless specified in the sales contract this additional value may not be reflected in the sales price but retained by a non-Alaskan entity. To avoid this, the State would require sellers to provide a record of the ultimate destination of cargoes and statement of the sale price at that destination, on which the taxable revenue of the plant would be estimated. To this end the State would need to maintain an independent view of LNG prices in the Asia Pacific region.

Exhibit A Asia Pacific LNG Demand and Supply Analysis

Characteristics of the LNG Market

Generally it is not possible to distinguish the market for LNG from the market for natural gas. This is certainly true of the major markets in Europe and the US and also in China and India. However, the core Asian markets of Japan, Korea and Taiwan are almost entirely dependent on LNG for their supplies of natural gas and in these countries there is a true LNG market. Two important elements flow from this:

- LNG demand is largely controlled by the availability of LNG supply at a cost that can compete in the market concerned.
- LNG supply will always flow in priority to the core Asian markets, and price in those markets will usually be higher than elsewhere.

In the US market LNG forms a very small proportion of total demand and price is set by competition between gas supplies. This is manifested in the Henry Hub price. Any LNG that can be landed, regasified and put into the US market at the Henry Hub price will find a place. Before the rapid rise in LNG investment cost since 2005 most LNG projects could meet this requirement as their marginal cost was less than the cost of much new unconventional US gas supply, which the US now relies on to replace declining conventional gas. The limiting factor was primarily the organisational and political difficulties of developing new LNG projects in many countries. However, LNG is even more capital intensive than pipeline gas and as costs have risen they have hit LNG development disproportionately. As a result LNG does not now possess such a clear cut competitive advantage and higher cost projects will struggle to compete while costs remain at current levels. The impact of high prices across the board has also had a dampening effect on US demand for gas which has been stagnant since 2000.

In Europe, where indigenous supply is in decline, LNG has to compete with pipeline gas. Europe is surrounded by large reserves of potential new gas supply. LNG therefore faces a rather similar competitive position as in the US. The main differences are that new sources of gas are distant from the main markets and in rather unstable or politically difficult countries. New pipeline projects are therefore also difficult and slow to develop. As a result there is a large appetite for LNG provided that it can be supplied at prices similar to current pipeline supply, which is linked to oil product prices and generally sits at 80-85% of crude oil parity in thermal terms.

China and India both have enormous latent demand for gas, which is largely unfulfilled as indigenous supplies are limited and imports were discouraged until relatively recently. Cost, however is also a major factor as both countries have abundant reserves of indigenous coal and are less willing to pay market prices for LNG that is far and above coal on a long term basis. LNG imports are competitive in some sectors where the alternative fuel is oil products but can only compete as a power generation fuel at prices close to the levels that obtained during the buyer's market of 2001 to 2004. So far there are very few LNG contracts supplying India and China. In general terms these closely resemble other Asian LNG contracts. Pricing has followed Asian practice at the time the deals were agreed. China had the good fortune to buy during the buyers market but India had to ask for its oil indexed price to be frozen for 5 years during the establishment of the market.

World LNG Overview

In summary:

- LNG trade is expected to continue to grow rapidly with world demand increasing at a CAGR of over 4% to 2030.
- Strong growth can be achieved in North America, provided supply can be made available at reasonable cost but this is by no means a foregone conclusion. The west coast market will always be limited by the difficulty of building terminals.
- Asian growth will be steady in the existing markets. China and India have the capacity to absorb large quantities of LNG but the quantity will be price sensitive. There is some demand at current high price levels but LNG at these prices is not competitive in the major power generation market. The situation is complicated by uncertainties in pricing policy for gas within both countries.
- Europe needs a very large quantity of new gas to replace declining indigenous supply and to meet market growth. Potentially Europe has many promising sources of new pipeline supply but many of them are in politically challenging regions and it is also proving difficult and slow to develop the major new pipeline corridors that would be required to bring the gas to market. As a result demand for LNG at existing oil linked price levels is strong.
- New liquefaction projects are needed to meet growing demand. At present, tight supply has created high prices and a sellers market but costs have also increased dramatically. Although there are a large number of identified potential LNG projects, a great deal of uncertainty surrounds the majority of them. After Qatar the main potential lies in Australia, Nigeria, Russia and Iran.
- Globally regasification capacity far exceeds potential supply to fill it.
- Worldwide growth of LNG demand is likely to be limited by the availability of supply at acceptable prices for the next decade at least.

LNG Trade in Asia Pacific

Markets in the Far East

The three leading buyers of LNG in the Far East are Japan, Korea and Taiwan. China has the potential to be a major player, too, although it is difficult to forecast its impact on the market in view of the alternatives available to it in the form of pipeline imports and indigenous production. Political intervention and the attitude of buyers to recent high prices will have a significant impact on future demand in the Chinese market. Similar considerations apply to India; there is high demand and a significant requirement for imports in the longer run. However, significant new reserves have been discovered and are being developed in the Krishna Godavari basin which will meet demand in the immediate future.

Japan is very much the market leader as the first and largest importer and has set price patterns for the others. Since the end of 2005 supply has been very tight. This has been the product of a number of factors; some revival of demand growth in Japan, combined with an unexpectedly rapid fall off in contracted supply from Indonesia as the result of reservoir problems and diversion of gas into the local market, and finally from emergency shut ins of Japanese nuclear power plant as a result of earthquake damage and maintenance problems which have increased the demand for gas fired power generation. New supply has not been able to come forward rapidly enough to fill this gap partly because LNG projects take a long time to mature and develop and partly because, although prices are high, costs have risen dramatically and have caused several high cost projects to reassess their economics.

The evidence that a sellers' market has developed is found in recent price settlements for LNG which, ex-ship, have been in the region of JCC oil parity.

Based on current contracted supply conditions, all three countries could continue to face supply shortages until 2011. However, by 2011or 2012 all the new Qatari supply anchored on the UK and US markets (some 46.8 mtpa) will be on stream and could be diverted or re-marketed into Asia if required. Qatar is currently only prepared to lock this in to Asian markets on high price terms, currently well above Henry Hub levels. As spot prices are often even higher than this Qatar can, for the moment, maintain a strong line. Asia seems most unlikely to continue short of supply, however, and the price is likely to depend on the strength of nerve exhibited by the various players.

Forecasting Methodology

We have confined ourselves to a single demand forecast for each of the main markets of interest. The main target markets of Japan , Korea and Taiwan are reasonably well understood and are not growing particularly rapidly and up to the period of main interest to the study i.e. 2015 to 2020 and therefore there are no major uncertainties. Supply, however, is much more problematic and therefore we have concentrated our analysis on the significant variability of supply against a single demand line in order to keep the number of variables within manageable proportions.

Throughout our forecasts we have used the rates of GDP growth for each relevant country given to us by the State of Alaska except for Taiwan where we have used our own forecast. Beyond 2025 we have assumed continuation of the 2025 growth rate for Japan and Taiwan. For the rapidly developing economies of South Korea, India and China, we have taken GDP rates from assessing the GDP of numerous immature to mature markets against energy consumption to determine GDP forecasts for these markets.

Exhibit Table 1 GDP Country and Regional growth rates and forecasts, 2000-2025

Key Countries	2000	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
North America	**4.0**	**3.1**	**3.0**	**2.3**	**2.5**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**2.7**	**2.8**
USA	3.7	3.1	2.9	2.2	2.4	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.7	2.8
Mexico	6.6	2.8	4.8	3.0	3.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2	2.8	2.8
Europe	**4.0**	**2.2**	**3.4**	**3.1**	**2.6**	**2.5**	**2.5**	**2.5**	**2.5**	**2.4**	**2.3**	**2.2**	**2.0**	**1.9**
Germany	3.1	0.8	2.9	2.7	2.1	2.2	2.0	2.1	2.2	1.8	1.6	1.3	1.2	1.0
France	3.9	1.7	2.0	2.0	2.3	2.0	1.9	2.1	2.0	2.0	2.0	1.9	1.8	1.7
Italy	3.6	0.1	1.9	1.8	1.6	1.5	1.7	1.7	1.6	1.4	1.3	1.2	1.2	1.0
UK	3.8	1.8	2.8	2.7	2.2	2.3	2.4	2.3	2.5	2.5	2.4	2.3	2.0	2.0
Spain	5.0	3.6	3.9	3.3	2.2	1.9	2.4	2.6	2.7	2.6	2.6	2.6	2.0	2.0
Asia Pacific	**6.0**	**7.2**	**7.8**	**7.8**	**7.2**	**6.4**	**6.2**	**5.9**	**5.8**	**5.6**	**5.6**	**5.1**	**4.5**	**4.1**
China	8.4	10.4	11.1	11.2	10.0	8.4	8.0	7.3	7.3	7.0	6.8	5.8	5.0	4.0
Japan	2.9	1.9	2.2	2.0	1.8	1.6	1.3	1.5	1.3	1.2	1.2	1.2	0.7	0.7
India	5.4	9.0	9.7	9.0	8.4	7.5	7.3	7.0	6.5	6.5	6.5	6.5	5.9	5.9
Korea	8.5	4.2	5.0	4.7	5.0	4.5	4.7	4.7	4.5	4.4	4.4	4.4	3.6	3.0
FSU	**8.9**	**6.6**	**7.7**	**7.0**	**6.3**	**5.8**	**5.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**3.5**	**3.5**
Latin America	**3.1**	**5.0**	**5.6**	**5.4**	**4.5**	**3.7**	**3.4**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**2.7**	**2.7**
Brazil	4.3	2.9	3.7	4.5	4.2	3.5	3.3	3.2	3.2	3.2	3.2	3.2	2.8	2.8
Middle East	**6.0**	**5.5**	**5.3**	**4.5**	**4.5**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.1**	**3.9**
Africa	**3.4**	**5.3**	**5.7**	**5.2**	**5.1**	**4.5**	**4.1**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**3.4**	**3.1**
Total World	**4.8**	**4.8**	**5.4**	**5.1**	**4.8**	**4.5**	**4.4**	**4.2**	**4.2**	**4.1**	**4.1**	**3.9**	**3.5**	**3.3**

Source: History: IMF, OECD, ADB, USDoC. Forecast: Wood Mackenzie

Residential and commercial gas demand is quite strongly linked to GDP growth once gas has achieved full penetration of the market. Where this is the case we have grown the residential and commercial market at a rate proportional to GDP. The actual ratio differs somewhat in different countries and we have used the rate appropriate to the country concerned. Where the market is not mature and distribution grids are still expanding we estimate the rate of new connections and average consumption by connection whenever this data is available, or use comparable rates based on experience of other countries where it is not. Industrial demand is also linked to growth rate.

Demand for electricity also grows at a rate determined by GDP growth. However, the proportion of electricity supplied by gas and hence the gas demand for power strongly depends on the mix of generating capacity over time. For about a decade ahead the plans for construction of new generating plant are quite reliable and give a strong guide to the amount of electricity that will be generated using gas fired power plant. Further into the future the plans are less secure and we take an overview based on past experience. For example Japan is targeting between 30 and 40% of electricity generation from 2030 but is most unlikely to achieve it. Similarly Korea Electric Power (KEPCO) is planning more coal and nuclear fired plant but is likely to face delays and problems with CO_2 targets, as they have in the past. In these cases we have taken an overview of the plans in the light of past experience and the likely obstacles to their achievement.

Japan

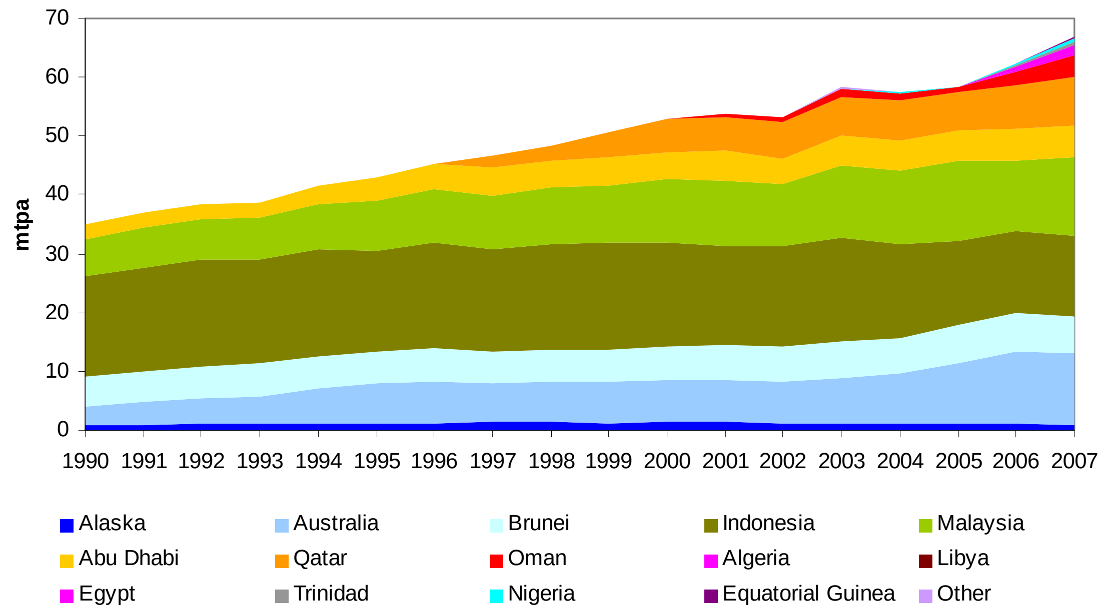
Market Overview

Japan has limited natural energy resources and relies heavily on imports for its primary energy supplies other than for hydropower. Gas is an increasingly important part of the Japanese energy supply mix, providing a degree of supply diversity as well as having lower environmental impact in terms of CO_2 emissions and waste handling, than other fuels.

Japan began importing gas in 1969, with deliveries from Kenai in Alaska for Tokyo Gas and Tokyo Electric. Consumption had consistently grown so that in 2007 total consumption had reached a peak of 66.9 mtpa, where Japan remains the world's seventh largest gas consumer and the largest importer of LNG. Since 1990, LNG imports has grown by 3.9% CAGR. In 2007, the three main countries Japan imported LNG from were Indonesia, Malaysia and Australia, accounting for 59% of all imports. The country is estimated to have only 1.4 Tcf in indigenous gas reserves and where domestic production is small accounting for only 310 mmcf/d (equivalent to about 2.3 million tonnes of LNG) in 2005, or just over 3.5% of gas supply. This is an increase of 6% from 296 mmcf/d in 2004.

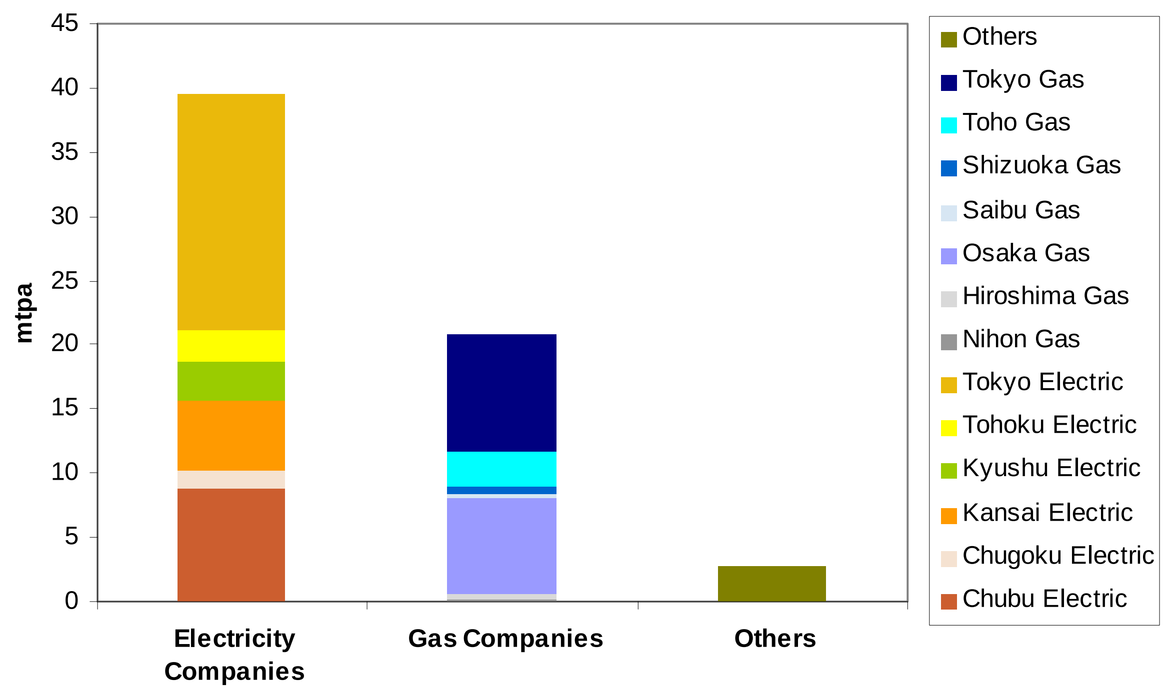
As can be seen in Exhibit Figure 2, the main importers and buyers of LNG are electricity companies with six of the ten regional power companies (Tokyo Electric, Chubu Electric, Kansai Electric, Tohoku Electric, Kyushu Electric, and Chugoku Electric) importing around two thirds of LNG supply. The three largest gas companies (Tokyo Gas, Osaka Gas, and Toho Gas) account for most of the remaining imports although, since the 1990s, a number of smaller gas companies (Saibu Gas, Nihon Gas, Shizuoka Gas, Sendai City Gas Bureau, and Hiroshima Gas) have imported LNG, in most cases in small tankers specially designed for smaller volumes.

Exhibit Figure 1 Japanese LNG Imports (1990 – 2007)



Source: Cedigaz, Gas Strategies Consulting

Exhibit Figure 2 Japanese Contracted LNG Imports in 2007 by Company



Source: Gas Strategies Consulting

Power generation accounts for nearly two thirds of consumption, the remainder being divided between residential, commercial and industrial use.

Japanese Gas Demand to 2050

There are a number of factors which will have a significant effect on Japanese energy consumption and the energy mix over the coming decades.

Japan ratified the Kyoto Protocol in 2003, committing the country to reduce greenhouse gas emissions by 6% by 2012 from 1990 levels. As part of the effort to meet this goal, the government is placing a strong emphasis on increased development of renewables and nuclear electricity generation, as well as promoting energy saving technologies to reduce current consumption levels. The government has proposed that the ratio of energy consumption to GDP be reduced by up to 30% using energy saving technologies and that its dependence on oil be reduced to about 40% by 2030, from current levels of about 50% of total energy consumption.

Electricity consumption in Japan has shown sustained growth of an average of 1.7% per year since 1990. Although all the LNG-importing power companies in Japan have a wide choice of fuels, this choice has been influenced by security of supply, cost, and environmental factors. Japan is struggling to meet its Kyoto targets, which drives it towards increased nuclear capacity. However, local opposition, which has strengthened following the well publicised maintenance problems makes siting new plants extremely difficult and time consuming. As a result Japan has consistently failed to meet its targets for nuclear generation. The gap has usually been made up by gas, which is the most acceptable fossil fuel but there has also been some new coal fired plant, largely on cost grounds.

Under a new energy strategy outlined in early 2006, the government has stated that it intends to increase the percentage of nuclear power in total national electricity supply from current levels of 30% up to around 40%. This target is also unlikely to be met and gas can again be expected to take up much of the slack.

Demand Forecast

A.1 Residential and Commercial Demand

Gas reaches about 50% of all households in Japan. This is low by the standards of Korea and the more developed gas markets of Europe but is limited by the nature of the terrain which effectively precludes the use of gas in rural, mountainous areas. The market is therefore relatively mature and we expect it to grow at a rate of rather less than GDP and closer to the growth in new dwellings. The average over the forecast period is 0.69% p.a.

A.2 Industrial Demand

Industrial demand in Japan has grown relatively rapidly, although it is a relatively low proportion of demand. Gas is priced highly in Japan and industrial demand is primarily in light industry where the alternative fuel would be LPG, gasoil or electricity. Demand is projected to grow at 4% above GDP.

A.3 Power Demand

As described above power generated by gas depends strongly on the availability of plant to the generators. We have followed generation plans up to about 2025 after which we expect gas to retain its share in the generation mix at about 17% at the expense of nuclear. This has only a minor impact on the nuclear target and is a conservative figure.

The gas demand forecasts to 2050 is shown in Exhibit Table 2, rising from 58mtpa in 2005 to 92.9 by 2030 and reaching 110.2 mtpa by 2050. Gas Strategies figures take a more progressive growth rate than the IEA and EIA, driven by the assumptions stated above.

Exhibit Table 2 Japanese Gas demand forecasts, 2005-2050 (mtpa)

mtpa	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	36.83	42.90	43.61	45.35	48.86	52.63	55.32	58.12	61.10	64.22
Industry	4.55	6.13	8.03	10.23	13.03	16.60	17.45	18.34	18.57	18.80
Feedstock	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Residential & Commercial	16.32	20.35	21.07	21.81	22.57	23.37	24.19	25.04	25.92	26.82
Total Demand	58.00	69.69	73.01	77.70	84.77	92.91	97.26	101.8	105.9	110.2
Source: Gas Strategies Consulting										

Exhibit Table 3 Japan - Other Demand Forecasts

mtpa	2010	2015	2020	2025	2030
IEA 2006	59.1	65.0	n/a	n/a	73.0
EIA 2007	73.9	80.1	82.1	86.2	88.3
Source: IEA World Energy Outlook 2006/EIA International Energy Outlook 2007 /Gas Strategies Consulting					

A.4 Gas Supply to Japan

Japanese LNG supply contracts are summarised in Exhibit Table 4.

Exhibit Table 4 Japan LNG Supply Contracts

Exporter	Importer	Volume (mtpa)	Start	End
NWS Australia LNG	Chubu Electric, Chugoku Electric, Kansai Electric, Kyushu Electric, Osaka Gas, Toho Gas, Tokyo Electric, Tokyo Gas	6.8	1989	2009
NWS Australia LNG	Chugoku Electric, Kansai Electric, Osaka Gas, Toho Gas, Tokyo Electric, Tokyo Gas	0.5	1996	2009
NWS Australia LNG	Tokyo Gas, Toho Gas, Osaka Gas	2.0	2004	2030
NWS Australia LNG	Tohoku Electric	0.5	2005	2020
NWS Australia LNG	Tohoku Electric	0.5	2010	2017
NWS Australia LNG	Kyushu Electric	0.5	2006	2030
NWS Australia LNG	Kyushu Electric	0.2	2009	2030
NWS Australia LNG	Shizuoka Gas	0.1	2005	2029
NWS Australia LNG	Chubu Electric, Kansai Electric	1.1	2009	2023
NWS Australia LNG	Tokyo Electric	0.3	2009	2016
Brunei LNG	Tokyo Gas, Osaka Gas	2.0	1973	2013
Brunei LNG	Tokyo Electric	4.0	1993	2013
Pertamina (Arun)	Tohoku Electric, Tokyo Electric	3.5	1973	2013
Pertamina (Arun/Bontang)	Chubu Electric, Kansai Electric, Osaka Gas, Kyushu Electric, Nippon Steel, Toho Gas	6.0	1977	2010
Pertamina (Bontang)	Chubu Electric	1.7	1983	2011
Pertamina (Bontang)	Osaka Gas, Tokyo Gas, Toho Gas	2.0	1994	2014
Pertamina (Bontang)	Hiroshima Gas, Nihon Gas, Toho Gas	0.4	1996	2016
Pertamina (Bontang)	Kansai Electric, Toho Gas, Osaka Gas	1.9	1983	2011
MLNG Satu	Tokyo Electric, Tokyo Gas	7.4	1983	2018
MLNG Satu	Saibu Gas	0.4	1993	2028
MLNG Dua	Tokyo Gas, Osaka Gas, Kansai Electric, Toho Gas	1.3	1995	2015
MLNG Dua	Tohoku Electric	0.5	1996	2015
MLNG Dua	Shizuoka Gas	0.5	1996	2016
MLNG Dua	Sendai City Gas Bureau	0.2	1997	2017
MLNG Tiga	Tohoku Electric	0.9	2005	2022
MLNG Tiga	Japex, Tokyo Gas, Toho Gas, Osaka Gas	2.1	2003	2020

Exporter	Importer	Volume (mtpa)	Start	End
Phillips/Marathon	Tokyo Electric, Tokyo Gas	1.2	1969	2009
Sakhalin Energy	Tokyo Gas	1.1	2007	2031
Sakhalin Energy	Tokyo Electric	1.5	2007	2029
Sakhalin Energy	Toho Gas	0.3	2010	2033
Sakhalin Energy	Kyushu Electric	0.5	2009	2029
Sakhalin Energy	Hiroshima Gas	0.2	2008	2028
Sakhalin Energy	Tohoku Electric	0.4	2010	2030
Sakhalin Energy	Chubu Electric	0.5	2011	2025
Sakhalin Energy	Osaka Gas	0.2	2008	2030
ADGAS	Tokyo Electric	4.7	1977	2019
Oman LNG	Osaka Gas	0.7	2000	2025
Qalhat LNG	Mitsubishi, Itochu	1.5	2006	2026
Qalhat LNG	Osaka Gas	0.8	2008	2028
Qatargas	Chubu Electric	4.0	1997	2022
Qatargas	Tokyo Gas, Osaka Gas	0.7	1998	2022
Qatargas	Tohoku Electric, Kansai Electric, Tokyo Electric, Chugoku Electric	1.1	1999	2022
Qatargas	Toho Gas	0.2	2000	2022
Darwin LNG	Tokyo Gas, Tokyo Electric	3.0	2006	2023
Pluto LNG	Tokyo Gas	1.5– 1.75	2010	2025
Pluto LNG	Kansai Electric	1.75-2.00	2010	2025

Source: Gas Strategies Consulting

A.5 Possible Extension of Contracts

Although Indonesia continues to remain Japan's largest LNG supplier, it has suffered significant production declines since 2004 due to the expected decline in gas production at the Arun field but also to unexpected feedgas shortfalls at the Bontang liquefaction plant. In 2004, Indonesia cancelled 41 cargoes to Japan, and the problems continue. Indonesia has attempted to replace the lost cargoes as far as possible by spot purchases but as of now it has a cumulative shortfall of 72 cargoes (over 4 million tonnes) to its Japanese Buyers. Tepco, the largest Japanese LNG buyer, indicated that it was unlikely to renew its long term contracts with Indonesia but Pertamina has negotiated extensions of supply for contracts expiring in 2010 amounting to 3 mtpa for 5 years and 2 mtpa for a further 5 years, rather than the existing 12 mtpa contracted from Bontang. The 3.5 mtpa from Arun will not be renewed.

The Alaskan supply from Kenai may continue for a few more years after 2009 but essentially its reserves are depleted.

Oman may not be able to offer full extensions of its contracts when they expire but these are not before 2025 at the earliest. Similarly Malaysia may not be able to fully extend all its contracts after the Tiga contracts start to expire in 2020 but we are expecting that Satu and Dua can be fully extended.

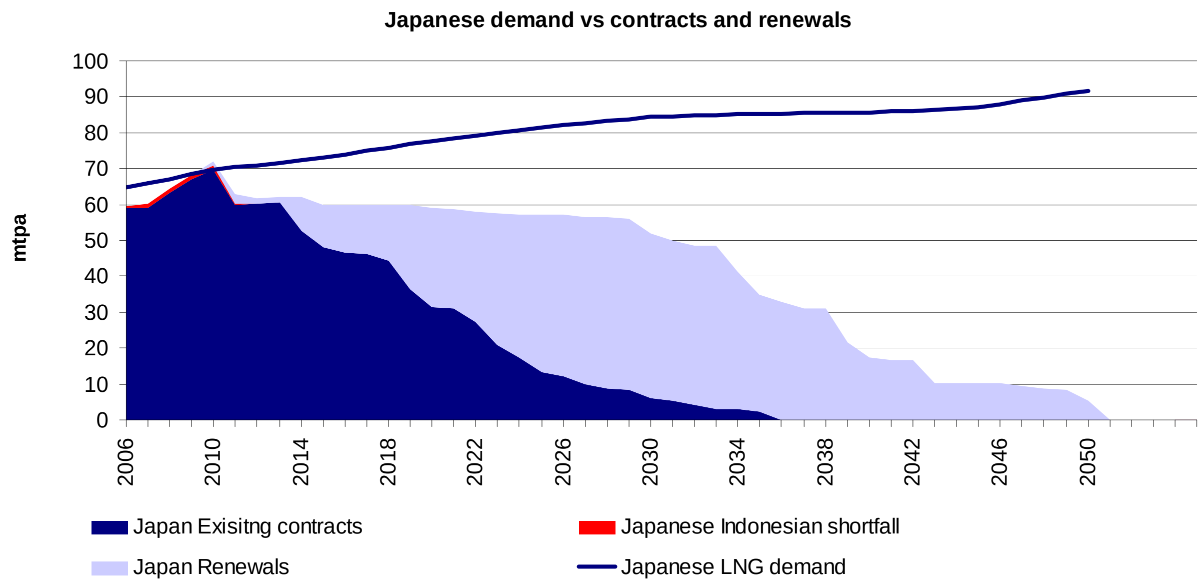
Brunei operates a restrictive depletion policy that requires a bank of reserves to be kept for future domestic use and this has raised a question mark over whether these contracts will be extended. However, there is no physical shortage of gas and the project has already ordered new ships in anticipation of extension and we fully expect these contracts to be extended.

Otherwise there is enough gas to support the renewal of all other supplies

A.6 Supply Demand Balance

Demand forecasts are compared with contracted supply and indigenous production in Exhibit Figure 3 below.

Exhibit Figure 3 Japanese LNG demand, contracted supply, 2006 - 2050



Source: Gas Strategies Consulting

Japan is currently short of gas. There is a notional small surplus in 2010 assuming Pluto starts up on time. By 2020 the deficit is expected to be 18.51 mtpa.

South Korea

Market Overview

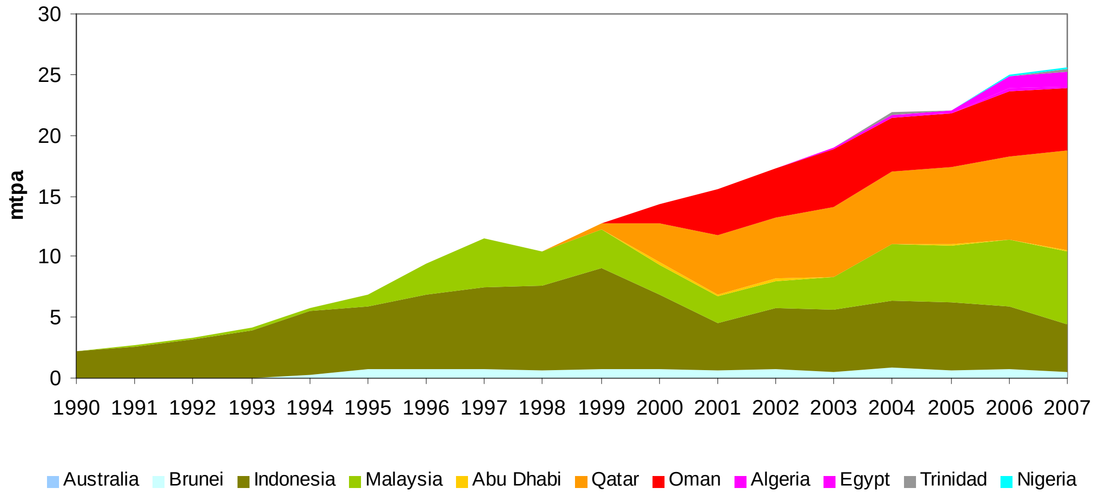
Energy consumption has grown rapidly in South Korea in line with the country's economic growth. Since 1980, primary energy supply has increased at an average rate of over 7% per year. Energy consumption fell sharply in 1998 as a consequence of the 1997/8 Asian financial crisis, but since then has grown, though at a lower rate than during the 1980s and early to mid 1990s. Energy intensity is higher than other industrialised countries due to the high proportion of energy intensive industries such as shipbuilding, steel and petrochemicals.

Oil accounts for about 50% of primary energy supply, and has accounted for most of the increase in energy demand since the late 1980s. South Korea relies on imports for almost all its energy requirements. Domestic coal production peaked in 1988 and has declined sharply since then. Strong emphasis is placed on energy diversification and security of supply.

Natural gas use in South Korea started in 1986 as a way to diversify the energy mix, with the first LNG imports from the Arun project in Indonesia. State-owned KOGAS is the largest single enterprise importer of LNG in the world and currently gas accounts for about 10% of primary energy supply.

Almost all South Korean gas supply comes from imported LNG and imported quantities are shown in Exhibit Figure 4. In 2007, South Korea imported 24.5 million tonnes of LNG. Since 1990, LNG imports have grown by 15.5% CAGR. In 2007, the three main countries South Korea imported LNG from were Qatar, Malaysia and Oman, accounting for 74% of all imports.

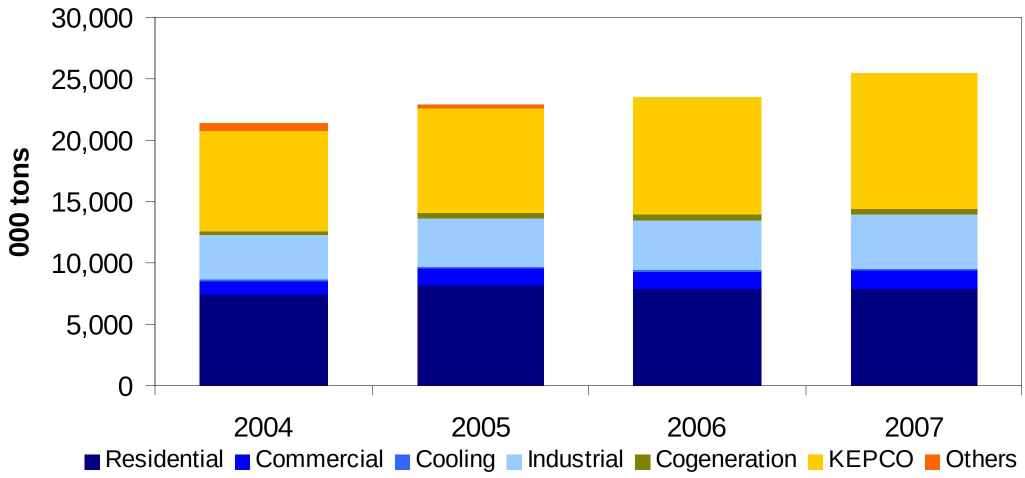
Exhibit Figure 4 South Korean LNG Imports by Country (1990 – 2007)



Source: Cedigaz, Gas Strategies Consulting

Since natural gas started to be imported into South Korea, KOGAS has had a monopoly on gas imports and sales to generators and gas distribution companies. There are currently 29 natural gas distribution companies, all supplied by KOGAS. State power company, KEPCO had a take-or-pay commitment to buy gas from KOGAS, which ended in November 2006. KOGAS owns and operates the pipeline network and three LNG terminals. KOGAS' sales by sector are shown in Exhibit Figure 5.

Exhibit Figure 5 KOGAS Sales by Sector, 2004-2007



Source: KOGAS/Gas Strategies Consulting

Although there have been plans to break up KOGAS into several companies as part of the process of liberalising the gas sector, the proposed timetable has been allowed to slip with changes in government and strong opposition from the KOGAS labour union. The rate of liberalisation is at a standstill and the eventual market structure remains uncertain. However, companies other than KOGAS have been allowed to import LNG for their own use since 2003. POSCO and K-Power were the first to do so, with the start of LNG imports through their Gwangyang terminal in 2005. The state-controlled electricity generators sought permission to import LNG, but were told that permission would only be granted if their deals were better than those which KOGAS could negotiate. So far they have failed to better KOGAS.

South Korea exhibits high seasonal demand variation, which has been managed through: use of storage at the LNG terminals, short-term purchases in the winter, a requirement for new projects to deliver their build-up volumes mainly in the winter, and co-operating with the generating company KEPCO.

Gas Infrastructure

KOGAS owns and operates the gas transmission network consisting of about 2,500 km of pipeline and three existing LNG terminals. In addition, POSCO, a South Korean steel company, has built a terminal at Gwangyang, which received its first cargo in May 2005 with full commercial operations commencing in July 2005. KOGAS is continuing to expand the pipeline network, and expects to increase gas penetration to 79% of households by 2015.

A.7 South Korean Gas Demand to 2050

Historically, demand in the electricity and residential sector have been similar, at about 35% and 37% of total respectively. Penetration of gas in the residential sector is high for the region and in 2005, about 70% of households were estimated to have access to natural gas. Penetration in industry is low as imported LNG is relatively expensive for bulk heat and much of Korea’s requirement is for heavy industry.

Growth in demand for natural gas is expected to continue to be strong, but it will be affected by a number of issues. These include economic growth, environmental factors, energy security, and the effects of gas and electricity market restructuring.

The South Korean economy has grown rapidly, with GDP growth averaging 8.4% per year in the ten years between 1987 and 1997. The economy shrank in 1998 as a consequence of the Asian financial crisis, but rebounded strongly, growing by 9.5% in 1999, and has been close to 5% p.a. since then. Our forecast shows a gradual slowing to 3% by 2025, stabilising thereafter.

While, until recently, environmental issues were given a low priority in favour of rapid economic growth, the South Korean government is now emphasising a policy of sustainable development and environmental protection. To this end, it has set a target of reducing oil’s share of energy supply to less than 45% from 50% by 2011 and has introduced several environmental measures that favour gas. It has also set a target of increasing the use of alternative energy to 5% by 2011. The 1990 Air Quality Preservation Act banned the construction of thermal power plants in the Seoul metropolitan area using fuels other than natural gas. The government is also promoting the use of CNG in road transportation, and is providing subsidies to bus companies to purchase new CNG buses. As of 2003, there were 4,312 CNG buses, and gas demand for transport was 0.4 million tonnes (0.55 Bcm).

Demand Forecast

A.8 Residential and Commercial

We have concurred with KOGAS plans for a small increase in penetration up to 2015, rising to a 79% penetration rate. This takes into account the rise in new connections as well as, evident in other markets, a rise in consumption correlating to a rise in GDP. As an annual growth rate we have a rate of 2.8% out to 2025 and gradually declining thereafter.

A.9 Industrial

Industrial demand is relatively small compared to the other sectors and its growth correlates very well with GDP; we have grown it in line with GDP.

A.10 Power

Power is based on an overview of Kepco's 3rd Long Term Power plan. The power plan conflicts with the Korean Government national energy plan, particularly in using more coal fired generation than the plan expects. Kepco's plan has in fact taken the view that some planned gas fired capacity (mainly owned by other companies) will not be constructed. It also envisages a considerable amount of new coal and nuclear power plant coming on stream between 2010 and 2020 which is run at high load factor and reduces gas demand. This is justified for nuclear power but we expect to see some slippage and some reduction in coal usage compared with the Kepco figures and have adjusted gas use upwards accordingly. In the longer term we expect gas to retain the same share of electricity output (15%) as it has in 2020 until 2030 and thereafter to grow at the same rate as GDP.

The gas demand forecasts to 2050 is shown in Exhibit Table 5, rising from 23.7 mtpa in 2005 to 47.0 by 2030 and reaching 73.4 mtpa by 2050. Gas Strategies figures take a higher growth rate than the EIA, driven by the assumptions stated above.

Exhibit Table 5 South Korean Gas demand forecasts, 2005-2050 (mtpa)

mtpa	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	9.70	15.70	15.31	17.92	19.79	21.84	25.32	29.36	34.03	39.45
Industry	3.95	4.99	6.21	7.41	8.59	10.21	11.83	13.72	15.52	17.56
Feedstock	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential & Commercial	10.07	11.20	12.26	13.26	14.16	14.94	15.56	16.02	16.28	16.34
Total Demand	23.72	31.88	33.78	38.88	42.54	46.99	52.72	59.09	65.83	73.35

Source: Gas Strategies Consulting

Exhibit Table 6 South Korea - Other Demand Forecasts

mtpa	2010	2015	2020	2025	2030
IEA 2006	n/a	n/a	n/a	n/a	n/a
EIA 2007	22.6	24.6	26.7	28.7	30.8

Source: IEA World Energy Outlook 2006/EIA International Energy Outlook 2007 /Gas Strategies Consulting

Gas Supply to South Korea

A.11 Indigenous Production

South Korea has a small amount of indigenous production, which started from the Donghae-1 field in late 2004. This is expected to be maintained for 15 years at 55 mmcf/d. This will be supplemented by production from the Gorae-8 and Gorae-9 fields, which have estimated reserves of 0.5 Tcf.

A.12 Contracted LNG Imports

South Korean LNG import contracts are summarised in Exhibit Table 7.

Exhibit Table 7 South Korean LNG Import Contracts

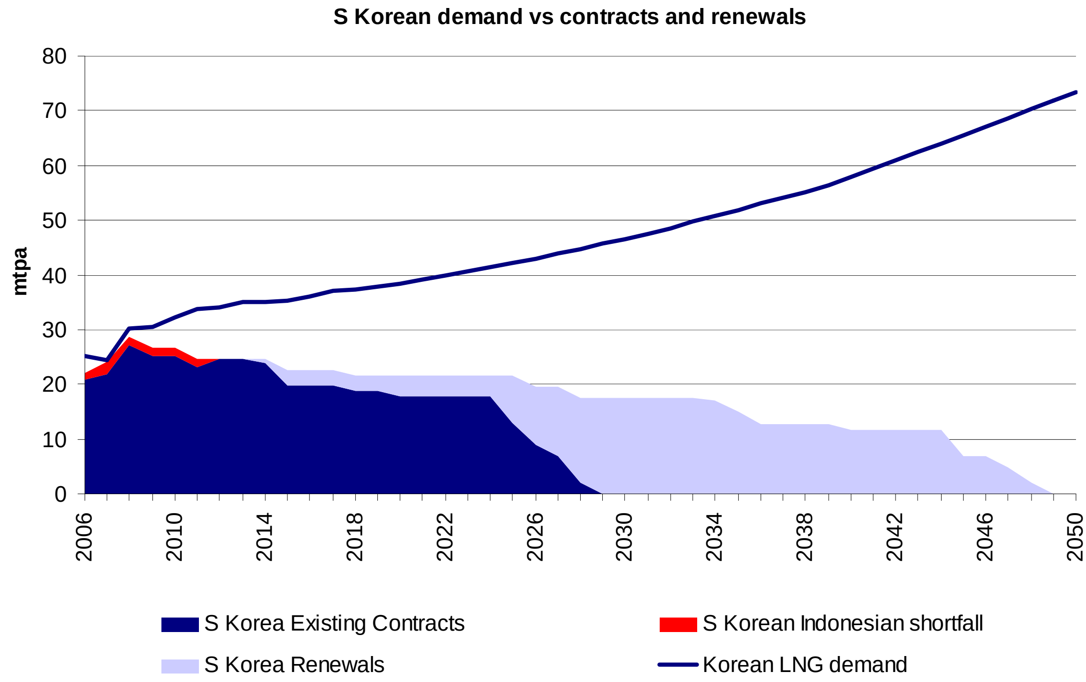
Exporter	Importer	Volume (mtpa)	Start	End
Brunei LNG	KOGAS	0.70	1997	2013
MLNG Dua	KOGAS	2.00	1995	2015
MLNG Tiga	KOGAS	1.50	2003	2010
MLNG Tiga	KOGAS	0.71	2004	2008
MLNG Tiga	KOGAS	0.40	2005	2008
MLNG Tiga	KOGAS	2.00	2008	2028
North West Shelf	KOGAS	0.50	2003	2010
Oman LNG	KOGAS	4.06	2000	2025
Pertamina (Bontang)	KOGAS	1.00	1999	2019
Pertamina (Arun)	KOGAS	2.30	1986	2007
Pertamina (Bontang)	KOGAS	2.00	1994	2014
Pertamina (Bontang)	KOGAS	1.00	1998	2017
RasGas	KOGAS	4.80	1999	2024
RasGas	KOGAS	0.96	2004	2008
RasGas	KOGAS	2.1	2007	2026
Sakhalin Energy	KOGAS	1.50	2008	2028
Tangguh	POSCO	0.55	2005	2025
Tangguh	K-Power	0.80	2006	2026
Yemen LNG	KOGAS	2.00	2008	2028

Source: Gas Strategies Consulting

A.13 Supply/Demand Balance

The demand forecast is compared with contracted supply and contracts, which could be extended (this includes all long term contracts except that from Arun, where the reserves are insufficient to extend the contract) in Exhibit Figure 6. Short-term contracts are expected to expire without renewal.

Exhibit Figure 6 South Korean LNG demand, contracted supply, 2006 - 2050



Source: Gas Strategies Consulting

As can be seen Korea is increasingly short of gas from now on. In fact the situation in 2008 is worse than it appears as the Sakhalin project start up is delayed until 2009 and Yemen will, at best, start up at the very end of 2008. As a result these volumes will not be available until next year. The deficit is just over 5mtpa in 2010 rising to 17.28 mtpa by 2020.

A.14 Pipeline Imports

KOGAS has been considering pipeline supplies from Russia. The most advanced plan is to deliver pipeline gas from Irkutsk.

The only route acceptable to China avoided Mongolia, which had been considered as a shorter and technically simpler (and cheaper) because the terrain is less mountainous. The proposed route would have two branches, one to Dalian and then a submarine pipeline to Pyeongtaek in South Korea, and the other to Beijing. The Kovykta reserves are estimated at 49 Tcf to 67 Tcf, and the proposed pipeline was scheduled to deliver 2.0 Bcf/d to China and 1.0 Bcf/d to South Korea, starting in 2008 and reaching plateau volumes by 2017. Commitment to such a project will now depend on agreement with Gazprom, which is being levered into the reserves and which has been appointed by the government to coordinate pipeline development, and is now, legally, the monopoly exporter of Russian gas.

The cost of the project is estimated at about $18 billion including $6.5 billion to develop the gas field and production facilities. There is a significant gap between the Chinese and Russian expectations with regard to gas price and the need to price pipeline supplies competitively with LNG in South Korea will add further complexity to the debate and negotiations appear to have stalled with little prospect of resolution.

Pipeline exports to South Korea from Sakhalin Island have also been proposed, though there is some discussion as to whether the gas from the Sakhalin I concession (ExxonMobil sponsored) should be used to expand the Shell-sponsored Sakhalin II LNG project. This pipeline would also require passing through North Korea, or a deep offshore section being constructed to by-pass North Korea. Currently KOGAS and the South Korean government have been giving priority to the Irkutsk pipeline project. Gazprom has also pursued the possibility of delivery from Chandinska, a field currently unlicensed in the Sakha Republic with reserves in excess of 1 Tcm; Gazprom would be reasonably confident that it will become a major licensee, if not the sole licence holder, for this field given the level of government ownership.

New LNG may eventually have to compete with these pipeline supplies but progress has been extremely slow and there is a realistic possibility that all the gas would go to China and not reach South Korea.

Taiwan

Market Overview

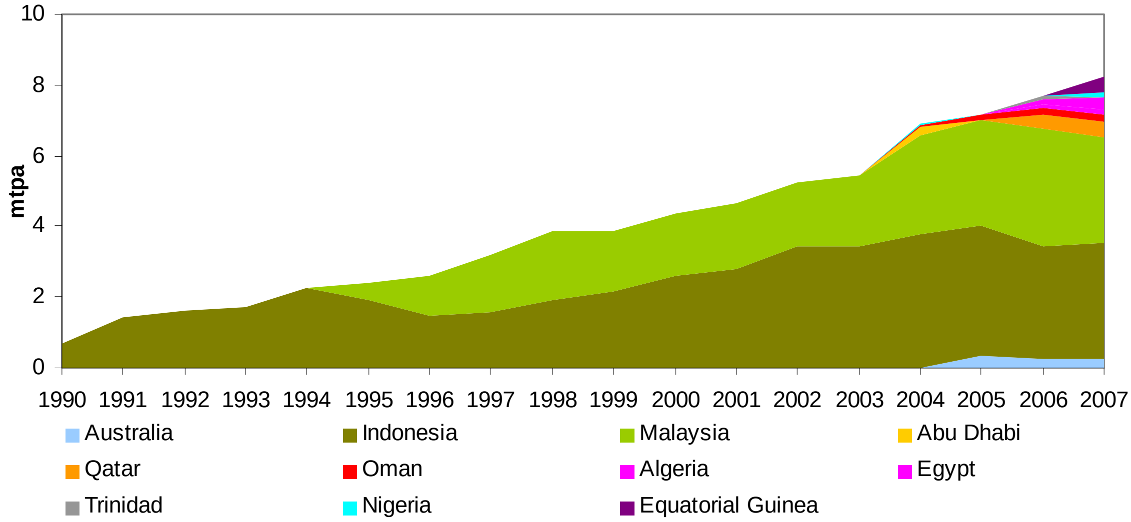
Taiwan also has few natural energy resources, and relies heavily on imports for energy supply. There is little scope for hydro generation, and nuclear power has not been promoted to nearly the same extent as in Japan or South Korea.

Oil is the largest primary energy source in Taiwan, accounting for almost half, 45%, of energy consumption. This is a reduction from 72% in 1980 as growth in oil consumption has not kept pace with coal and more recently gas. Since the introduction of the first LNG supplies in 1990, gas has been the fastest growing fuel, averaging 11.2% per year in a period when total primary energy supply has grown at a rate of 5.3% per year. Most of the growth in gas consumption has been driven by the power sector. In 2007, there was a significant increase in LNG imports to 8.4 million tonnes from 7.7 million tonnes in 2006, as new gas-fired power plants came online.

Energy intensity is higher than most industrialised countries as a result of the concentration of energy intensive industries within the economy.

Taiwan has a small amount of proven gas reserves, estimated at no more than 2.8 Tcf in 2004. Indigenous production is small and has remained fairly constant at about 80 mmcf/d over the last decade. The majority of gas is imported as LNG. LNG imports started from Indonesia in 1990. In 2007, the three main countries Taiwan imported LNG from were, Indonesia, Malaysia and Qatar, accounting for 82% of all imports.

Exhibit Figure 7 Taiwan Gas Supply 1990-2007



Source: Cedigaz; Gas Strategies Consulting

The Chinese Petroleum Corporation (CPC) is the only natural gas supplier in Taiwan. It is responsible for gas production and LNG import through its terminal at Yung An, just north of Kao-hsiung in southern Taiwan. The terminal had a high construction cost and as a result, natural gas is expensive. This is one reason that gas has not achieved the market share it might have had if the supply cost structure had been more competitive. The other main reason is that CPC is also the national oil company and has not been particularly gas focussed.

Electricity consumption in Taiwan has grown steadily at an average rate of 6.6% per year since 1990. Most of the increased demand has been met by coal, which accounts for 55% of electricity generation and increasingly, gas-fired plants.

Gas Infrastructure

There is currently one LNG terminal in Taiwan with a reported capacity of 7.44 mtpa. Actual capacity, however, is likely to be higher, probably closer to 10 mtpa. The terminal was expanded in 1996 and a pipeline built from Yung An to Tungsiao, increasing the capacity to deliver gas from the terminal in the south-west of Taiwan to the principle demand area near Taipei in the north.

A second terminal had been planned for Tatan in the north of the island for several years to supply an adjacent 4 GW power station and other customers in northern Taiwan. A tender to supply 1.7 mtpa to Taipower's Tatan power station was won by CPC. CPC has signed a contract with RasGas for 3.0 mtpa to supply this contract and replace the contract for 1.5 mtpa with Indonesia, which expires in 2010. CPC decided to build the terminal at Taichung rather than Tatan to import this additional LNG. The terminal was scheduled to start up in early 2008 but the pipeline connecting it to shore has been delayed and it is now expected to take its first regular cargo in early August. It is reported that this terminal will have an initial capacity of 3 mtpa but this has the potential to be expanded.

Taiwan Gas Demand to 2050

Taiwan suffered little compared with its neighbours during the Asian financial crisis. However, Taiwan slipped into recession in 2001 as a consequence of a downturn in the world economy and bad debts in the banking system. Output recovered moderately in 2002 with a GDP growth of 3.9% but was hampered by the continued global slowdown, fragile consumer confidence, and bad bank loans. Since 2001, GDP growth has averaged 4%. Growing economic ties with China are a dominant long-term factor in Taiwan's economic growth. Increasingly strong export performance, in particular to China, is driving strong economic growth. We project that GDP growth will decline gradually from 4.3% in 2008 to 3.5% per annum in 2015 and remain at 3.5% thereafter.

Electricity generation accounts for about 70% of natural gas consumption in Taiwan, and is expected to continue to be the main area of demand growth as the government pursues its strategy of diversifying Taiwan's supply mix and meeting its environmental objectives. Industry accounted for 16% of natural gas consumption in 2003, but demand growth has slowed considerably due to a decline in output in sectors, which are intensive gas consumers, such as glass and ceramics. In the residential and commercial sectors demand growth has been limited by the competitiveness of LPG compared with natural gas, the limited coverage of the distribution network, and the high fixed costs of connecting new residential customers. Clearly gas penetration in the industrial, residential and commercial markets will depend on price, in part to offset the initial cost of the import terminal and secondly to encourage switching.

A.15 Residential and Commercial

Residential and commercial demand is quite mature given its relatively weak position and is projected to continue to grow more slowly than GDP and at a slightly declining rate through the forecast period.

A.16 Industry

Industrial demand growth correlates closely to GDP growth in Taiwan and is projected to grow at this rate through the period.

A.17 Power and Heat

Power is the dominant sector and is the most important component of the estimate. Overall electricity demand grows at a rate just under the GDP growth rate. However, as with Korea and Japan, gas is only one component of the fuel mix and for the early years we have therefore used Taipower's plans as the basis for the projection. The most important element of this is that the two 1,350 MW units of the 4th nuclear power plant are due to start up in 2009 and 2010 which has the result of flattening gas demand in power between 2010 and 2014 when growth resumes at a rate of about 4% per annum.

The gas demand forecasts to 2050 is shown in Exhibit Table 8, rising from 7.6 mtpa in 2005 to 24.0 by 2030 and reaching 47.5 mtpa by 2050.

Exhibit Table 8 Taiwan Gas demand forecasts, 2005-2050 (mtpa)

mtpa	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	5.33	8.06	10.25	12.98	15.78	19.06	22.93	27.45	32.73	38.90
Industry	1.23	1.54	1.83	2.18	2.59	3.07	3.65	4.33	5.15	6.11
Feedstock	0.04	0.06	0.07	0.08	0.09	0.11	0.13	0.16	0.19	0.22
Residential & Commercial	0.95	1.10	1.25	1.41	1.58	1.73	1.89	2.03	2.15	2.26
Total Demand	7.55	10.74	13.40	16.65	20.03	23.98	28.60	33.97	40.22	47.49

Source: Gas Strategies Consulting

Gas Supply to Taiwan

CPC has four contracts to import LNG from Indonesia, Malaysia and Qatar's RasGas. The details of these contracts are shown below.

Exhibit Table 9 Taiwan LNG Contracts

Exporter	Importer	Volume (mtpa)	Start	End
Pertamina	Indonesia	1.5	1990	2010
Pertamina	Indonesia	1.84	1998	2018
MLNG Dua	Malaysia	2.25	1995	2015
RasGas (II)	Qatar	3.0	2008	2033

Source: Gas Strategies Consulting

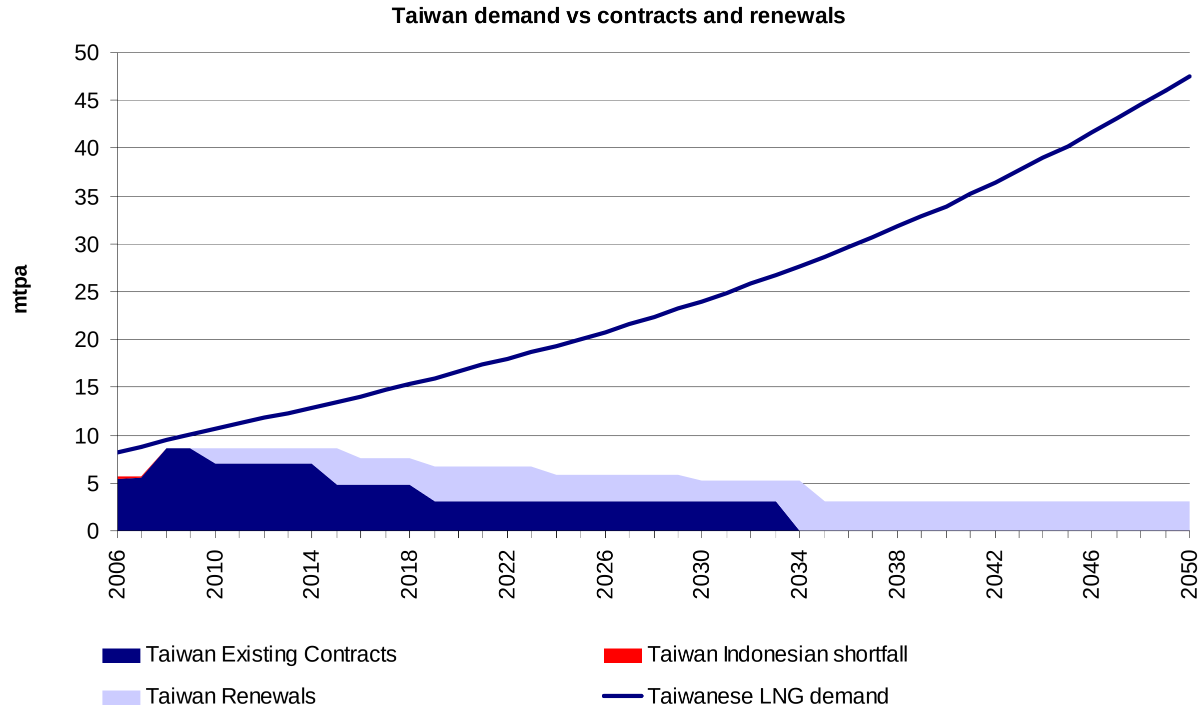
Note that the RasGas contract starts at 1.7 mtpa and only ramps up to 3.3 mtpa by 2011, although RasGas has the capacity in principle to supply at full rate from the start.

Pertamina has been under delivering compared with its contractual obligations. The shortfall is expected to be 6 cargoes or 350,000 tonnes in 2008.

Supply Demand Balance

Demand forecasts and contracted supply are shown below in Exhibit Figure 8. Both Pertamina contracts are expected to expire.

Exhibit Figure 8 Taiwan LNG demand, contracted supply, 2006 - 2050



Source: Gas Strategies Consulting

Currently, gas consumption exceeds Taiwan's contracted supply volumes, due in part to the rising demand for gas in the electricity sector and under-deliveries in Indonesian supplies since 2004. In 2007 Taiwan purchased 1.9 million tonnes of LNG on the spot market. The requirement for new LNG is just over 2 million tonnes (assuming RasGas delivers 3 million tonnes) rising to 10 mtpa by 2020.

China

Market Overview

Chinese gas consumption is low in relation to its population. This is a consequence of it having large and well-developed coal reserves, whilst at the same time being relatively poor in gas reserves estimated at 86 Tcf at the end of 2006. As an additional barrier to increased utilisation, most of the gas reserves are in the relatively undeveloped western provinces, while demand is concentrated in the east and south-eastern regions. However the situation is changing and China has actively sought to develop its gas industry both to promote development in the western provinces and as a response to concerns about pollution. As a consequence, gas pipelines have been built to carry gas from the Ordos basin to Beijing and the West-East pipeline to carry gas from the Tarim basin to Shanghai.

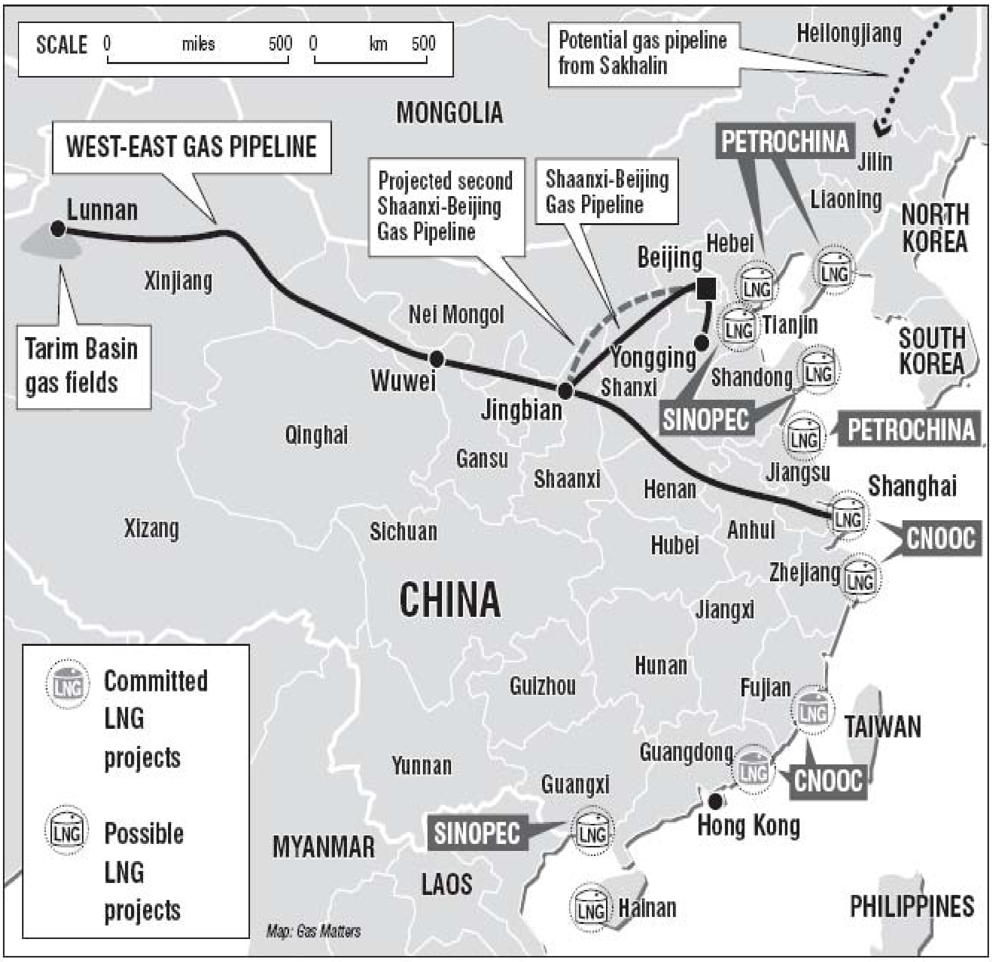
Natural gas accounts for only about 2% of primary energy consumption in China and in 2006, gas consumption reached 6 Bcf/d, up 17% from 5.1 Bcf/d in 2005. Natural gas is supplemented by some distribution of LPG and more extensively by manufactured gas, either from naphtha or coal. In 2006 the first LNG supply to the Guangdong terminal from Australia started up and demand has already run ahead of the contracted 3.7 mtpa.

Gas Infrastructure

There are currently 20,000 km of gas pipelines in China, but more will be needed to bring gas from Russia and the remote west, from north to south, from the South China Sea and from the 10 proposed LNG terminals. It is thought that China needs to build a further 15,000 km of gas pipelines by 2020 to cope with fast growing demand.

China's main domestic gas trunkline is the 4,000 km West-East pipeline completed by China's state-owned CNPC in January 2005. Natural gas from the hydrocarbon-rich western Xinjiang province and other gas sources alongside the pipeline route is transported to Shanghai in eastern China. The pipeline passes through 10 provincial regions on its route to Shanghai and has an annual capacity of 1.2 Bcf/d, which is planned to be increased to 1.7 Bcf/d by 2010.

Exhibit Figure 9 Gas Infrastructure in China



Source: Gas Matters

There are several regional gas pipelines including the second longest domestic pipeline, the Shaan-Jing Parallel pipeline, which started operations in 2004 supplying 6 regions including Shandong and Beijing with about 390 mmcf/d. CNPC has plans to expand China's domestic network with the construction of two cross-country natural gas trunk lines and six regional gas pipeline networks in Southwest China, Hunan-Hubei, Northwest China, North China, East China and Northeast China by 2015. A draft Five-Year Plan for 2006-2010 submitted to China's National People's Congress in February 2006, reinforced these plans.

The draft plan calls for the development of China's national oil and gas network to offset the energy disadvantage of some areas caused by imbalanced geographical distribution. The plan also provides for the construction of a second West-East pipeline and another pipeline for the importation of gas to China's inland areas. PetroChina is reported to be conducting a feasibility study for the second West/East pipeline to be operational by 2010, with a capacity of 3.0 Bcf/d.

China does not have any international gas pipelines at present, although it is involved in several negotiations to import gas via pipelines from Russia, Kazakhstan and Turkmenistan.

There are three LNG regasification terminals under construction in China, all of which are owned by CNOOC with various partners. Phase 1 of the Guangdong terminal became operational in May 2006 and phase 2 is due in 2008. The Fujian terminal is due on stream in 2009 and an expansion is already under construction for a 2010 start up.

The third terminal in progress is the Yangshan terminal in Shanghai which is scheduled to be operational in 2009.

Exhibit Table 10 Chinese LNG Import Terminals – existing and planned

Province	Company	LNG Import Start Date	Initial Capacity mtpa	Planned Future Capacity mtpa	LNG supply
Fujian	CNOOC	2008	2.6	2.4	2.6 mtpa from Tangguh
Guangdong	CNOOC	2006	3.7	2.5	3.7 mtpa from North West Shelf
Guangxi	Sinopec	2010+	3.0	N/A	Not committed
Heibei	Petrochina	2010+	6.0	4.0	Not committed
Jiangshu	Petrochina	2011+	3.5	2.5	3 mtpa from National Iranian Gas Export Company (Heads of Agreement, 2011 – 2035)
Liaoning	Petrochina	2012	4.0	2.0	Not committed
Shandong	Sinopec	2010+	3.0	2.0	Not committed
Shanghai	CNOOC, Shenergy	2009	3.0	3.0	3 mtpa from 2009 and 6 mtpa from 2012, Bintulu, Malaysia
Tianjin	Sinopec	2012	3.0	N/A	Not committed
Zhejiang	CNOOC	2010+	3.0	3.0	Not committed
Hainan	CNOOC	2009	2.0	3.0	At proposal stage [1]
TOTAL			**35.8**	**34.4**	

Source: Gas Strategies Consulting

[1] *Hainan's current demand for gas stands at over 7.3 Bcm/year against a supply of 5 Bcm/year by indigenous pipeline*

Although more than 20 terminals had been proposed in the country, in August 2005, China's National Development and Reform Commission (NDRC) suspended approval for several proposals and issued an order limiting the number of terminals to be constructed to one per province, with the exception of Guangdong where two would be permitted. The NDRC has granted conditional approval to 7 other terminals owned by CNOOC, Sinopec and PetroChina, pending the negotiation of LNG supply contracts. None of these seven has yet started construction.

China's Gas Demand to 2050

Because the gas industry is very immature in China its growth prospect depend as much on increasing penetration and on availability of supply as on economic growth. In the five years to 2005, gas consumption in China grew by an average of 15% per annum. GDP growth is also expected to continue to be rapid starting at 10% in 2008 and gradually easing to 4% by 2025.

Based on the foregoing, Gas Strategies has developed the following total demand scenarios for China as shown below.

Gas is not being encouraged in the power sector in areas where there is abundant coal. In any case LNG fuelled CCGT can only realistically compete with coal in areas like Guangdong which are distant from the main coal mines and then only with LNG prices in the $4.50 - $5.00/mmBtu landed cost. Nevertheless gas fired power will gain share as the three gorges project is not easily repeatable.

The other sectors are constrained not to grow above GDP because of the constraints of providing infrastructure and obtaining gas supply.

The gas demand forecasts to 2050 is shown in Exhibit Table 11 below, rising from 35.2 mtpa in 2005 to 284.6 by 2030 and reaching 1229.6 mtpa by 2050.

Exhibit Table 11 China Gas demand forecasts, 2005-2050 (mtpa)

mtpa	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	4.01	8.38	15.75	30.62	64.17	138.11	223.83	390.44	567.01	830.48
Industry	16.24	25.84	35.98	45.92	55.86	69.62	94.04	127.04	171.62	231.84
Feedstock	6.43	10.22	14.23	18.16	22.10	27.54	37.20	50.26	67.89	91.72
Residential & Commercial	8.48	16.92	25.48	34.30	41.97	49.32	56.48	63.66	69.77	75.53
Total Demand	35.16	61.36	91.43	129.00	184.10	284.58	411.56	631.40	876.29	1229.57

Source: Gas Strategies Consulting

Exhibit Table 12 China Gas demand forecasts, 2005-2050 (Bcf/d)

Bcf/d	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	0.57	1.11	2.09	4.06	8.50	18.30	29.65	51.73	75.12	110.02
Industry	2.35	3.42	4.77	6.08	7.40	9.22	12.46	16.83	22.74	30.72
Feedstock	0.95	1.35	1.89	2.41	2.93	3.65	4.93	6.66	8.99	12.15
Residential & Commercial	1.23	2.24	3.38	4.54	5.56	6.53	7.48	8.43	9.24	10.01
Total Demand	5.10	8.13	12.11	17.09	24.39	37.70	54.52	83.65	116.09	162.90

Source: Gas Strategies Consulting

Exhibit Table 13 China - Other Demand Forecasts

mtpa	2010	2015	2020	2025	2030
IEA 2007	n/a	95.6	n/a	n/a	173.7
EIA 2007	61.6	82.1	102.7	123.2	143.7

Source: IEA World Energy Outlook 2007/EIA International Energy Outlook 2007 /Gas Strategies Consulting

Prospects for Gas Supply

Historically the Chinese government has preferred to aim for self sufficiency in energy as far as possible, with the aim of increasing indigenous production to 9.2 Bcf/d by 2010 although it is unlikely that this aim will be realised. In reality China is unlikely to achieve more than 6.8 Bcf/d.

China has a number of options available to increase its gas supply:

- Develop domestic reserves to the maximum extent;
- Use pipeline imports from neighbouring countries such as Russia, Kazakhstan and Turkmenistan
- Import LNG

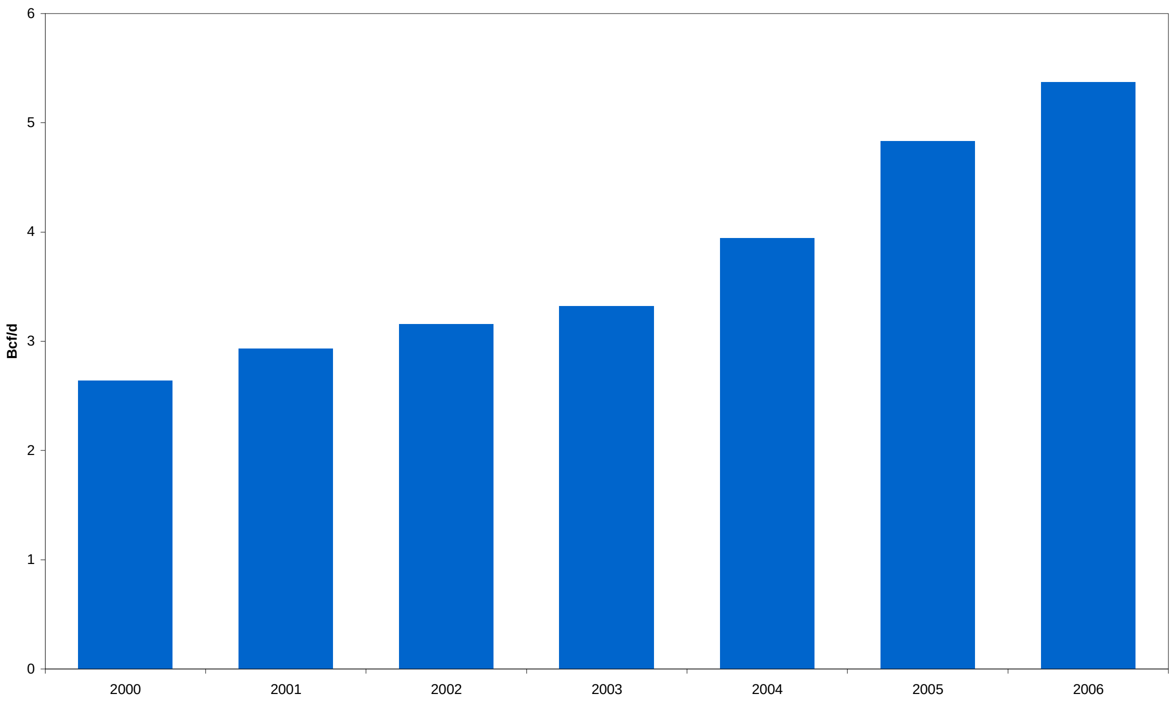
In the more affluent eastern and southern coastal regions China is more willing to experiment with imports at international price levels. This was the basis for the first LNG terminal in Guangdong province and China has now approved LNG import terminals to be built by CNOOC in Guangdong, Fujian Shanghai and Zhejian, by Petrochina in Jiangsu, Heibei and Liaoning; and by Sinopec in Shandong, Tianjin and Guangxi provinces (see Exhibit Table 10). Each terminal will be capable of importing around 3 mtpa at start up with the potential to expand to at least 6-7 mtpa in a second phase of construction.

A.18 Domestic Natural Gas Production and Coal Bed Methane

China is estimated to hold 86 Tcf in domestic reserves, with 6 significant fields discovered since 1999 in the Tarim, Sichuan, and Ordos basins onshore and offshore in the Bohai Basin in the East China Sea and off Hainan and the Pearl River Delta in the South China seas.

In addition to this growing resource, China is estimated to have up to 1094 Tcf of coal bed methane (CBM) reserves, of which 565 Tcf are considered to have good development prospects.

Exhibit Figure 10 China Indigenous Gas Production, 2000-2006 (Bcf/d)



Source:EIA / Gas Strategies Consulting

China's gas production for 2006 is believed to have been 5.37 Bcf/d, an increase from 4.83 Bcf/d in 2005. We expect China's gas production will reach 6.8 Bcf/d in 2010, 9.9 Bcf/d in 2020 and 12.5 Bcf/d in 2030.

Rising gas prices have enhanced the economics of the CBM production and there is growing interest in developing China's reserves. In 2005, the first CBM-fired power generator became operational and there are plans to convert some coal plants to CBM. Most of the proposals for CBM power generation have been for small and medium sized units.

Import Requirement

The gap between forecast demand and indigenous production can only be made up by imports. If these do not materialise the demand will be left unsatisfied.

The requirement is shown in the following table:

Exhibit Table 14 China Gas demand requirements, 2010 - 2030

Bcf/d	2010	2015	2020	2030
Demand	8.1	12.1	17.1	37.7
Domestic Supply	6.8	9.3	11.8	12.5
Gap	1.3	2.8	5.3	25.2
Gap (mtpa)	9.8	21.5	40.0	190.2

Source: Gas Strategies Consulting

These numbers probably represent a minimum. The market could absorb more gas if it were available.

A.19 Pipeline Imports

China is considering pipeline gas supplies from Kazakhstan, Turkmenistan and Russia. In 2005, CNPC purchased Petrokazakhstan in a $4.2 billion deal. Since then, the gas subsidiary of state-owned KazMunaiGaz has announced that it would undertake a feasibility study on the construction of a gas pipeline to connect Kazakhstan's gas fields to China's West-East pipeline.

China has also had discussions with Turkmenistan for the construction of a 3.0 Bcf/d gas pipeline from eastern Turkmenistan to China's Xinjiang Province (still 2500 miles from Shanghai). The project is estimated to cost up to $10 billion. Because of the distances and costs involved and the lack of intermediate markets these projects represent a major economic challenge and are not likely to go ahead quickly. It is unlikely that gas from Turkmenistan or Kazakhstan will be transported through the West-East pipeline until domestic resources along its route are fully developed.

Russia is also considering the construction of one or two pipelines with capacity totalling 6.8 Bcf/d initially using gas from western Siberia and later from the Kovykta field in Eastern Siberia or Chayandinska in the Sakha Republic as the main sources. These options are also very high cost as they involve long distances to reach the market. They have been under negotiation for several years but have come nowhere near agreement as the Russians and the Chinese have fundamentally different approaches to pricing and their negotiating positions are way apart.

We would not expect to see gas flowing from Turkmenistan before 2015 and the first Russian pipeline not until 2020.

In addition, a connection from Sakhalin to Khabarovsk, in the Russian Far East, is already under construction and the line will initially handle 300 mmcf/d for sale in the Khabarovsk Krai. Khabarovsk is on the Russian-Chinese border and the line capacity could be increased. This small sale is likely to proceed but could be the precursor of a larger sale.

A.20 Prospects for LNG Supply

In many of the eastern coastal locations LNG replaces manufactured gas in local distribution systems. There is also a significant commercial and industrial segment that uses LPG as fuel. LNG at international prices has no difficulty in competing in these sectors. However in the power sector LNG has effectively to compete with coal (often even in areas where there are supposed to be environmental restrictions on the construction of new coal fired plant). LNG can do this at the sort of prices agreed for the imports to Guangdong but not at current levels. Furthermore, the government has also revealed its unwillingness to purchase gas at any cost, as demonstrated by CNOOC's inability to reach a compromise with Chevron on the price of proposed LNG supplies from Gorgon in late 2005. As high oil prices have persisted, however there seems some sign that China will be prepared to buy some LNG at the going price provided these high prices can be "rolled in" with cheaper domestic supply of gas (similar to US LNG purchases from Algeria in the 1970s). Within the last few weeks there have been two new deals each for about 3 mtpa with Qatar and Woodside that are believed to be at similar levels to the most recent Japanese prices. This is only realistic in areas such as Shanghai where there is some indigenous supply. The situation is complicated by the lack of a uniform pricing policy within China. In general the supplier has to negotiate with individual end users such as power generators and local distribution companies to sell regasified LNG. Where both LNG and indigenous gas supplies are available there is the opportunity to generate a rolled in supply price, although this is a risky strategy economically. Uncertainty will remain until more gas development has taken place and China has enacted some coherent gas legislation.

We do not expect China to meet its own ambitions for internal gas supply in 2010 nor do we expect international pipeline imports on a substantial scale before the 2015 – 2020 period. Therefore we do expect a substantial residual appetite for gas in China which could be met by LNG, but not at any price.

For reasons which must by now be apparent it is very difficult to predict how much LNG China will actually import. Potentially the country could use very large quantities but price and the fact that LNG is imported are inhibitions. The rapid growth of the market following the start of LNG imports to Guangdong is likely to be replicated as terminals are built and the infrastructure developed. In many cases these will have to be supplied by LNG as China does not have anything approaching a national gas supply grid and several of the LNG terminals will not have access to an alternative pipeline source.

China will not be the most attractive buyer for LNG suppliers if, as expected LNG supply is restricted. Not only is it likely to be more price sensitive than the core Asian markets but there are also questions over the credit worthiness of the smaller buyers. We therefore expect to see China playing something of a swing role, absorbing LNG if and when LNG supply starts to exceed what the core Asian markets can take.

China already had contracted LNG supply for the three terminals under construction as follows:

Exhibit Table 15 China LNG Contracts

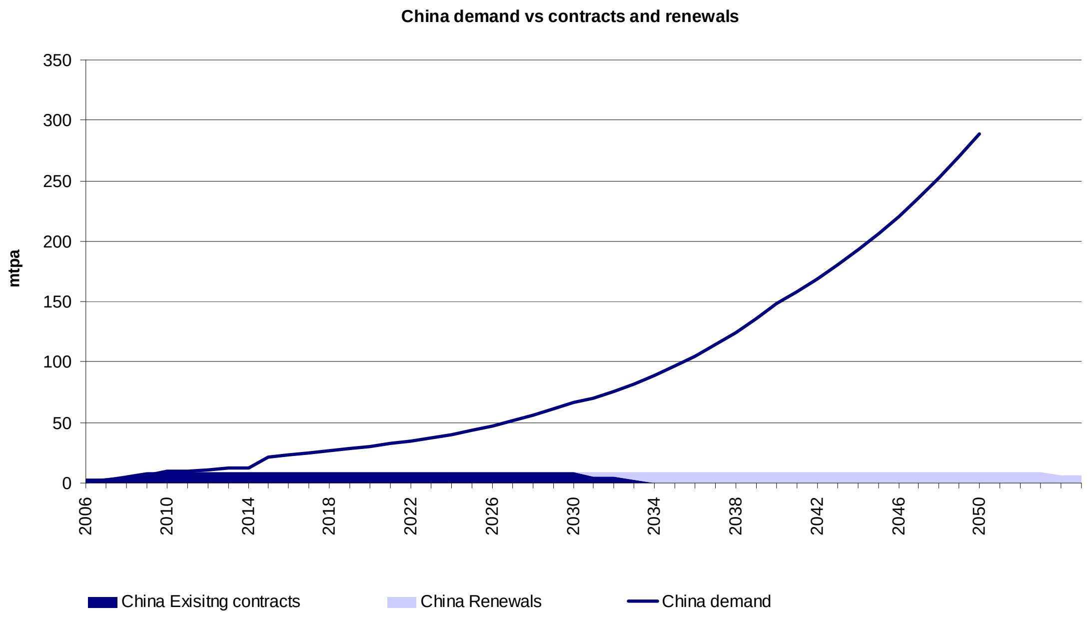
Exporter	Importer	Volume (mtpa)	Start	End
NWS	Australia	3.7	2006	2026
Tangguh	Indonesia	2.6	2008	2028
MLNG Tiga	Malaysia	3.0 – 6.0	2009	2029
Source: Gas Strategies Consulting				

The net import requirement is as follows:

Exhibit Table 16 China LNG Import requirements, 2010 - 2030

mtpa	2010	2015	2020	2030
Import Need	9.8	21.5	40.0	190.2
Contracted LNG	9.3	12.3	12.3	0
Gap	0.5	9.2	27.7	190.2
Source: Gas Strategies Consulting				

Exhibit Figure 11 China LNG demand, contracted supply, 2006 - 2050



Source: Gas Strategies Consulting

Up to 2015 LNG is the only realistic source of this supply. From then on there is the potential for pipeline gas from Central Asia and Russia, although there is likely to be only limited competition between the two because of the geographical isolation of many of the Chinese regional markets. In our LNG demand assumptions, we have thus accounted for the gas pipeline from eastern Turkmenistan to China's Xinjiang Province coming online in 2020, accounting for 3.0 Bcf/d.

A.21 Hong Kong

Hong Kong and China Gas (HKCG) distributes manufactured gas (and some piped LPG) throughout the territory. One of Hong Kong's two power generators, Hong Kong Electric, started taking LNG from the Guangdong project in 2006 and HKCG is also taking supply as feedstock to make manufactured gas.The other power generator, CLP, takes about 220 mmcf/d natural gas from the large Yacheng offshore gas field south-west of China's large Hainan Island via a 778 km pipeline to the Castle Peak power plant. CLP is now considering a new LNG receiving terminal of its own in Hong Kong.

India

The other fast growing emerging market in the Asia/Pacific region is India.

Driven by strong economic growth, energy consumption in India has been growing at a Compound Annual Growth Rate (CAGR) of around 5.3% over the last two decades. The CAGR for world primary energy consumption over the same period was 1.9%. India's total primary energy demand has increased from 126 MMtoe in 1985 to 387 MMtoe in 2005[2]. Reflecting the shift in economic output, energy consumption has shifted toward the services and transport sectors, and away from the agriculture and industry sectors. Industry, however, still remains the largest primary energy user. While the overall primary energy consumption has been increasing, the per capita consumption is still well below that of the developed nations.

Coal with a share of around 55 % has been the dominant source of primary energy. However natural gas has increased its share during the last decade, through increased domestic production by private players and LNG imports. The demand growth of natural gas has traditionally been anchored in the power and fertiliser sectors, with the industrial segments increasing their share over the last decade.

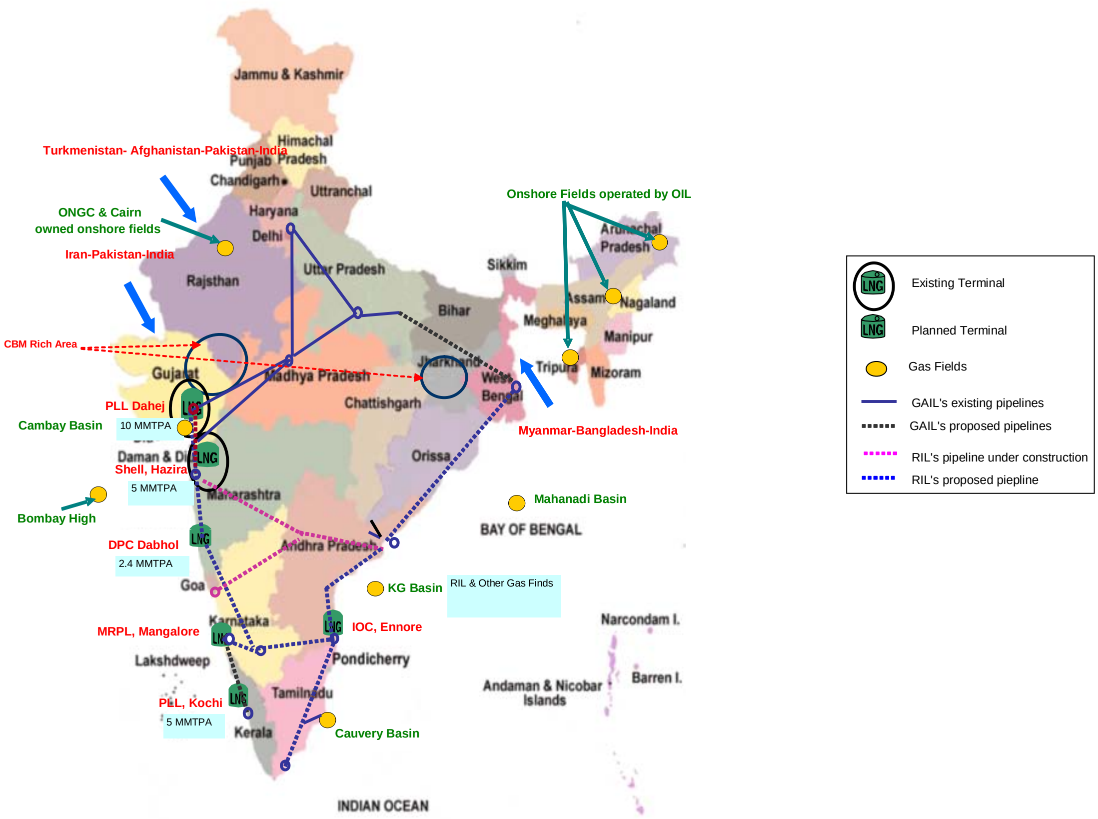
Gas Demand to 2050

The share of natural gas in primary energy supply has increased from only 1.3% in 1981 to 8.5% in 2005. All India demand for natural gas at the end of 2007 was estimated to be 4.21 Bcf/d, but supplies were only around 3.11 Bcf/d, resulting in huge demand supply gap. In 2007 as in past years the natural gas market in India was constrained by supply.

The map below shows the existing and planned infrastructure developments for India .

[2] Source BP Statistics June, 2006.

Exhibit Figure 12 India infrastructure map



Source: Gas Strategies Consulting

We define realisable demand as demand from customers who have connectivity to pipeline infrastructure. The demand depicted is an aggregate of the existing, expansion and switching demand. Switching gas demand is demand resulting from units operating on alternate fuels such as Naphtha / Fuel Oil / Light Diesel Oil switching over to gas. Expansion gas demand is demand from brown-field /green-field capacity additions in various sectors.

By 2015, around 60% of the demand for natural gas will be from the existing and switching projects and the balance of 40% is expected from expansion projects. Currently power is the dominant sector, accounting for over 40% of the total gas consumption in the country, followed by the fertiliser sector, which accounts for close to 30% of the total consumption. The power sector is likely to retain its dominance throughout the forecast period.

Drivers of natural gas demand growth in India

Broadly, the following factors are expected to drive the increased consumption of natural gas in India:

➢ **Macroeconomic setting and policy making**

Overall macroeconomic conditions in the economy will set the demand for energy and the growth rate of energy demand. India has been enjoying higher growth rates since the early 1990s because of economic reforms. Economic growth has been robust and sectors like consumer durables, cars, two-wheelers and telecommunications are seeing strong growth. This growth will contribute to greater demand for energy.

- **Cost of gas vis-à-vis alternate liquid fuels**

  With the recent increase in crude oil prices, the prices of alternate liquid fuels like naphtha, fuel oil, Low Sulphur Heavy Stock (LSHS), etc. has also gone up. In comparison, gas prices have remained steady and the difference in the price with respect to liquid fuels is likely to spur growth in gas consumption in all the sectors. Ever under the changed scenario of market determined pricing, natural gas will be priced at a discount to alternate fuels and hence will continue to remain attractive.

- **Growth of end-user segments**

  The robust growth outlook for the Indian economy and the resultant increase in the end–user consumption of the natural gas is expected to drive the natural gas market in the future.

- **Regulation**

  The regulatory mechanism[3] in the future is expected to attract, enable and sustain much needed capital into the sector. It will also ensure that consumer interests and those of industry participants are protected.

- **Environmental concerns**

  Reduction in the level of carbon emission has been a key area of concern for some time now. Gas is preferred as it has lower carbon emissions per unit energy generated. The promotion of gas can win certified emission reduction credits and CDM project developers can gain financially from such projects / transactions.

- **New uses of Natural Gas (e.g. co-generation)**

  Natural gas is being considered as “single fuel solution”, replacing power and fuel for heating and cooling requirements. Use of gas in co-generation of power, refrigeration and heating (CCHP - Combined Cooling, Heating & Power) gives much higher fuel efficiency. Given the economic advantage in terms of efficiency, industrial and commercial establishments are expected to switch to the single fuel application, once gas becomes available.

Our analysis of demand is based on a very detailed assessment of the individual sectors down to individual large plant level up to 2030. After that time we have used GDP correlations to project demand out to 2050.

Power: For the forecast period, capacity additions both announced and unannounced have been considered to arrive at our projections.

[3] The Petroleum & Natural Gas Regulatory Board Act, 2006 has already been enacted and the Board is in advanced stages of being formed.

Fertiliser: Natural gas is used both as a feedstock as well as a fuel in the urea industry in India. Apart from natural gas, urea units utilise alternate fuels / feedstock such as naphtha and fuel oil / low sulphur high stock. These units can, after incurring certain investments to switchover, shift to natural gas and are therefore, potential consumers.

Industrial consumers: The demand projections of small and medium industrial consumers have been estimated based on the existing unmet requirements and the likely switchover / growth in consumption as more supplies enter the market. To capture the likely expansion in industrial demand, with expansion in supply pipelines and availability of additional supply volumes, we have linked industrial natural gas demand to growth in replacement of Fuel Oil at 2% p.a.

City Gas Distribution: Currently, there are four big distribution entities in the country namely Indraprastha Gas Ltd. (IGL), Mahanagar Gas Ltd. (MGL), Gujarat Gas Company Ltd. (GGCL) and Gujarat Adani Energy Limited (GAEL). Some new setups have started to function recently. Future projects have been considered based on their likely schedule of implementation.

The gas demand forecasts to 2050 is shown in Exhibit Table 17 below, rising from 25.3 mtpa in 2005 to 127.5 by 2030 and reaching 225.7 mtpa by 2050.

Exhibit Table 17 India Gas demand forecasts, 2005-2050 (mtpa)

mtpa	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	11.23	22.03	34.67	38.65	45.38	54.79	65.24	77.67	92.48	110.11
Industry	6.86	18.08	25.42	28.06	30.98	34.21	37.77	41.70	46.04	50.83
Feedstock	6.51	14.12	22.08	22.08	22.08	22.08	22.08	22.08	22.08	22.08
Residential & Commercial	0.66	2.11	5.24	10.19	13.52	16.42	20.85	26.47	33.61	42.67
Total Demand	25.26	56.35	87.40	98.98	111.97	127.51	145.94	167.93	194.22	225.70
Source: Gas Strategies Consulting										

Exhibit Table 18 India Gas demand forecasts, 2005-2050 (Bcf/d)

Bcf/d	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Power & Heat	1.49	2.92	4.59	5.12	6.01	7.26	8.64	10.29	12.25	14.59
Industry	0.91	2.40	3.37	3.72	4.10	4.53	5.00	5.52	6.10	6.73
Feedstock	0.86	1.87	2.93	2.93	2.93	2.93	2.93	2.93	2.93	2.93
Residential & Commercial	0.09	0.28	0.69	1.35	1.79	2.18	2.76	3.51	4.45	5.65
Total Demand	3.35	7.47	11.58	13.11	14.83	16.89	19.33	22.25	25.73	29.90
Source: Gas Strategies Consulting										

Exhibit Table 19 India - Other Demand Forecasts

mtpa	2010	2015	2020	2025	2030
IEA 2007	n/a	42.3	n/a	n/a	81.7
EIA 2007	41.1	41.1	61.6	61.6	82.1
Source: IEA World Energy Outlook 2007/EIA International Energy Outlook 2007 /Gas Strategies Consulting					

Supply Projections

A rapid increase in overall supply is expected, through a combination of greater indigenous production, and imports through transnational pipelines and as Liquefied Natural Gas (LNG). Accordingly, while projecting total supply, the following categories of supplies have been considered – domestic gas (consisting of volumes from existing fields, new domestic discoveries[4], and CBM) and gas imports (consisting of existing and upcoming LNG terminals and proposed transnational pipelines).

The most striking element of Indian supply is the discovery of a major field in the Krishna Godavari Basin by Reliance in 2002, which has been followed by further subsequent finds in the basin. This provides a major injection of supply for the next decade.

The methodology of supply projections is detailed below:

- Existing fields: Supplies based on LTGP[5] projections.
- Announced discoveries (Approved by DGH): Supplies based on the development plans filed with DHG.
- Possible additions to future supplies: Based on reserve accretion methodology
- LNG: Supplies linked to terminal capacity and LNG import contracts.
- CBM and Translational Pipelines; Based on our understanding and our discussions with the industry players.

Exhibit Table 20 India Gas supply projections, 2005 - 2030

Bcf/d	2010	2015	2020	2025	2030
Existing fields	1.9	1.0	0.4	0.2	0.1
New Domestic	3.1	4.5	5.2	5.5	5.3
CBM	0.1	0.3	0.3	0.3	0.3
LNG	1.2	1.6	1.6	2.3	3.6
Total	6.2	7.4	7.5	8.3	9.3
Source: Gas Strategies Consulting					

[4] Fields awarded under NELP

[5] The Long Term Growth Plan (LTGP) is a projection regarding the likely volume of gas from existing ONGC owned fields to 2016-17 by ONGC submitted to the Directorate General of Hydrocarbons (DGH).

A.22 Projected supplies from existing and planned LNG terminals

The Dahej terminal of PLL and the Hazira terminal of Shell are the completed LNG projects in India. The Dabhol LNG project of Ratnagiri Gas and Power Project Limited (RGPPL) is likely to be completed by end of FY2009. LNG supplies will be influenced by terminal capacity and the LNG import contracts. The following sections provide details of LNG supplies from these projects.

Exhibit Table 21 India Gas demand requirements, 2010 - 2030

Bcf/d	2010	2015	2020	2025	2030
Demand	7.5	11.6	13.1	14.8	16.9
Domestic Supply	4.9	5.5	5.6	5.7	5.4
Gap	1.3	4.2	5.6	6.5	7.6
LNG	1.2	1.6	1.6	2.3	3.6
LNG (mtpa)	12.0	17.0	17.0	24.0	37.0

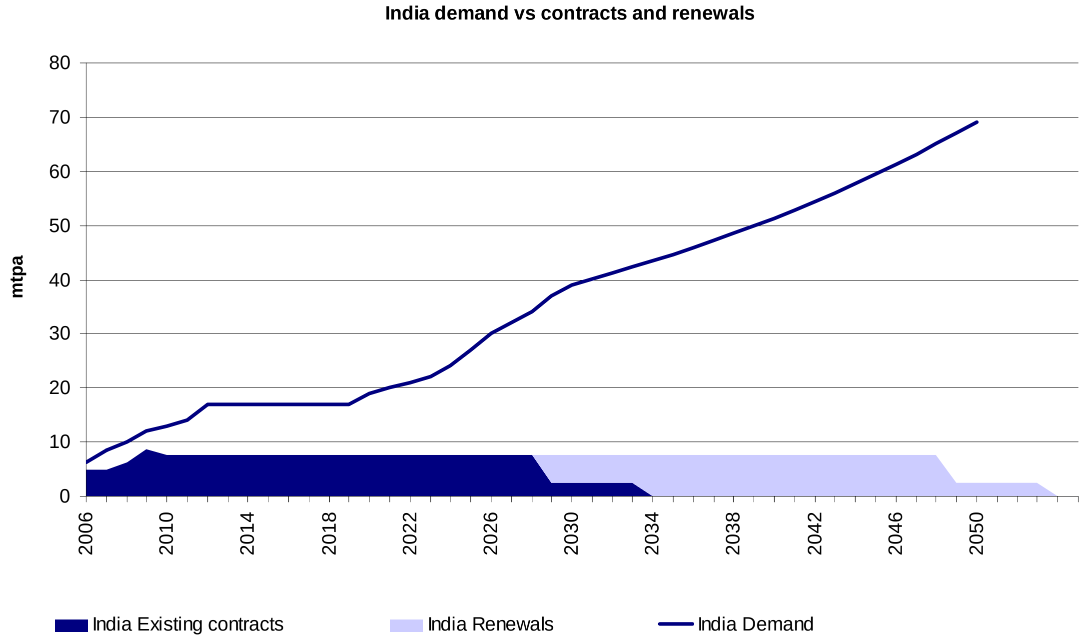
Source: Gas Strategies Consulting

Exhibit Table 22 LNG Supplies and Contracted Volumes – Base Case

LNG terminal	Capacity	Contracted Volumes	Remarks
Dahej - PLL	Current Capacity – 5 Mtpa FY10 7.5Mtpa FY12 10 Mtpa	Qatar - RasGas 5 Mtpa (2004- 2028) +2.5 Mtpa Second Tranche	FY12 – 2.5 Mtpa will be uncontracted ; which can be met with supplies from Iran or other sources, which PLL is actively seeking
Hazira - Shell	Current Capacity – 2.5 Mtpa FY15 5 Mtpa	No long term contracts exist. Supplied from Shell portfolio – spot. Has been short of supply.	Terminal expected to achieve 2.5 Mtpa in FY08 and 5 MMTPA in FY15 by either spot or long term contracts.
RGPPL, Dabhol	Current Capacity – nil FY09 – 2.4 Mtpa	No long term contracts exist. Earlier sourcing plan: 1.6 Mtpa - Oman LNG, 0.7 Mtpa – Adgas. 2.6 Mtpa -Petronas. Project stalled due to financial and legal difficulties	The commissioning of 2,184 MW Dabhol power project to drive LNG volumes Actual operations dependant on LNG availability, and domestic gas volumes availability.

Source: EIA/Gas Strategies Consulting

Exhibit Figure 13 India LNG demand, contracted supply, 2006 - 2050



Source: Gas Strategies Consulting

Exhibit B Potential LNG Supply

The previous section has reviewed gas demand in the main Asian markets and established the requirement for new gas, with particular attention to the 2015 to 2020 period during which Alaskan LNG would be coming to market and starting up. There are some 22 other LNG projects in the Pacific and Middle East regions which have been announced. However the majority of them are subject to major uncertainty, which makes predicting when they might be serious contenders very uncertain. We have not attempted to assess yet to find gas that might eventually be considered for development as LNG. There is too much uncertainty in this to come to any valid conclusions.

LNG projects are notoriously difficult to bring to market but are also have distinctly variable histories. To illustrate the point, three major gas discoveries were made in 1971: Arun in Indonesia, North Rankin in North West Australia, and the North Field in Qatar (which becomes South Pars in Iranian waters). Arun delivered its first cargo in 1977, still the most rapid LNG development that has been achieved. The Australian North West Shelf LNG project started up in 1989, and Qatargas in 1997. No Iranian project has yet made its final investment decision. Three other major gas discoveries made in North West Australia at about the same time, Gorgon, Scott Reef and Scarborough which have still not been developed but are seen as active projects. The first suggestion of an LNG project in Nigeria was in the late 1960s and the first deliveries were in 1999. The reasons for the differences are complex and far from exclusively economic. For example, cost was and is a major factor in Australia but politics also played a major part; Australia took a long time to decide whether exports were acceptable. When it had taken the decision the NWS project was held up for some time as demand stagnated in Japan in the recession following the 1979 oil shock, although the Japanese buyers had committed in principle to take the LNG. The licences had been granted to a very small Australian exploration company (Woodside) that had to find partners to be able to fund the development, without surrendering its independence. This also took years of negotiation to solve.

It is therefore challenging to forecast which projects are likely to proceed at a given time. We use a multi-pronged approach based on our understanding of the individual projects. We aim to assess what each project must do to put itself in a position to take its final investment decision, e.g. prove reserves, set up a joint venture structure and agreements, sell LNG, come to agreement with the host country, carry out necessary design work, negotiate finance, acquire shipping etc. as well as achieving satisfactory economics.

Methodology

This section provides a comprehensive list of the projects we have assessed. These projects have been grouped into three key categories:

1. **Operating Projects:** projects in existence and already producing.
2. **Projects Under Construction**: Projects which are already under construction or for which an Engineering, Procurement and Construction contract has been awarded.

For categories 1 and 2 we have assessed the likelihood of the existing production levels (and contracted volumes) being sustained in the period in question.

Exhibit Table 23 Existing/Under Construction LNG Projects in Asia Pacific/Middle East

REGION	PROJECT	START DATE
OPERATING PROJECTS		
AP	Brunei	Existing
AP	Darwin Train 1	Existing
AP	NWS Trains 1 – 4	Existing
AP	Indonesia - Arun	Existing
AP	Indonesia – Bontang	Existing
AP	Malaysia	Existing
ME	Oman LNG Trains 1 & 2	Existing
ME	Qalhat	Existing
ME	Adgas	Existing
ME	Qatargas 1 – 3	Existing
ME	RasGas 1 – 5	Existing
PROJECTS UNDER CONSTRUCTION		
AP	NWS T5	2009
AP	Peru LNG	2010
AP	Pluto LNG	2011
AP	Sakhalin Trains 1 & 2	2009
AP	Tangguh Trains 1 & 2	2009
ME	Qatargas 2	2008/9
ME	Qatargas 3	2010
ME	Qatargas 4	2011
ME	RasGas Trains 6 & 7	2009/10
ME	Yemen LNG Trains 1 & 2	2009

Source: Gas Strategies Consulting

3. **Probable Projects:** Projects which have been formally proposed either linked to certain or fairly certain reserves and for which a timeline for establishment have been proposed.
4. **Possible Projects:** Possible projects include those for which an LNG project is being considered, for the development of established reserves or those for which an LNG project has been identified as the goal in the search for reserves.
5. **Speculative projects:** Projects for which there is no current existing structure but which might reasonably assumed to develop in the future based on the prevalence of gas in the country and an existing or aspiring LNG business.

Existing projects and their futures

Contracts associated with existing projects

The table below shows all of the existing contracts for buyers in the Asia Pacific region. It can be seen that all of the contracts expire before the end of the timeline used in this project.

Exhibit Table 24 LNG contracts into Asia

	Exporter	Importer	Country	Volume (mtpa)	Start	End
Australia NWS	North West Shelf	Chubu Electric	Japan	1.05	1989	2009
	North West Shelf	Chugoku Electric	Japan	1.11	1989	2009
	North West Shelf	Kansai Electric	Japan	1.13	1989	2009
	North West Shelf	Kyushu Electric	Japan	1.05	1989	2009
	North West Shelf	Osaka Gas	Japan	0.68	1989	2009
	North West Shelf	Toho Gas	Japan	0.23	1989	2009
	North West Shelf	Tokyo Electric	Japan	1.18	1989	2009
	North West Shelf	Tokyo Gas	Japan	0.79	1989	2009
	North West Shelf	Chugoku Electric	Japan	0.11	1996	2009
	North West Shelf	Kansai Electric	Japan	0.11	1996	2009
	North West Shelf	Osaka Gas	Japan	0.07	1996	2009
	North West Shelf	Toho Gas	Japan	0.02	1996	2009
	North West Shelf	Tokyo Electric	Japan	0.11	1996	2009
	North West Shelf	Tokyo Gas	Japan	0.07	1996	2009
	North West Shelf	Chugoku Electric	Japan	1.20	2009	2021
	North West Shelf	Kansai Electric	Japan	0.40	2009	2017
	North West Shelf	Osaka Gas	Japan	0.50	2009	2015
	North West Shelf	Tokyo Electric	Japan	0.30	2009	2017
	North West Shelf	Tokyo Gas	Japan	0.53	2009	2017
	North West Shelf	Toho Gas	Japan	0.76	2009	2019
	North West Shelf	Kyushu Electric	Japan	0.73	2009	2017
	North West Shelf	Kogas	Korea	0.50	2003	2010
	North West Shelf	Tokyo Gas/Toho Gas	Japan	1.00	2004	2029
	North West Shelf	Osaka Gas	Japan	1.00	2004	2034
	North West Shelf	Tohoku Electric	Japan	0.40	2005	2020

	North West Shelf	Shizuoka Gas	Japan	0.14	2005	2029
	North West Shelf	Kyushu Electric	Japan	0.50	2006	2026
	North West Shelf	Chubu Electric	Japan	0.60	2009	2023
	North West Shelf	Kansai Electric	Japan	0.50	2009	2023
	North West Shelf	Tohoku Electric	Japan	0.50	2010	2018
	North West Shelf	Guangdong LNG	China	3.30	2006	2031
Australia Darwin	Darwin	Tokyo Electric	Japan	2.00	2006	2023
	Darwin	Tokyo Gas	Japan	1.00	2006	2023
Australia Pluto	Pluto	Tokyo Gas	Japan	1.5-1.75	2010	2025
	Pluto	Kansai Electric	Japan	1.75-2.00	2010	2025
Brunei	Brunei LNG	Tokyo Gas	Japan	1.24	1972	2013
	Brunei LNG	Tokyo Electric	Japan	4.03	1972	2013
	Brunei LNG	Osaka Gas	Japan	0.74	1973	2013
	Brunei LNG	Kogas	S. Korea	0.70	1997	2013
Indonesia - Arun/Bontang	Pertamina	Tohoku Electric	Japan	3.00	1984	2004
	Pertamina	Tokyo Electric	Japan	0.13	1984	2009
	Pertamina	Kogas	S. Korea	2.30	1986	2007
	Pertamina	Chubu Electric	Japan	2.15	1977	2010
	Pertamina	Chubu Electric	Japan	1.68	1983	2011
	Pertamina	CPC	Taiwan	1.58	1990	2009
	Pertamina	Osaka Gas	Japan	1.27	1994	2013
	Pertamina	Tokyo Gas	Japan	0.92	1994	2014
	Pertamina	Toho Gas	Japan	0.11	1994	2013
	Pertamina	Kogas	S. Korea	2.00	1994	2014
	Pertamina	Hiroshima/Nihon/ Osaka Gas	Japan	0.40	1996	2015
	Pertamina	Kogas	S. Korea	1.00	1999	2019
	Pertamina	Kansai Electric	Japan	2.57	2000	2010
	Pertamina	Osaka Gas	Japan	1.30	1977	2010
	Pertamina	Kyushu Electric	Japan	1.56	1977	2010
	Pertamina	Nippon Steel Corp.	Japan	0.55	1977	2010
	Pertamina	Toho Gas	Japan	0.05	1977	2010
	Pertamina	Kansai Electric	Japan	0.89	1983	2011
	Pertamina	Kogas	S. Korea	1.00	1998	2017
	Pertamina	CPC	Taiwan	1.84	1998	2018
	Pertamina	Toho Gas	Japan	0.56	1983	2011
	Pertamina	Osaka Gas	Japan	0.45	2004	2011
Indonesia - Tangguh	Tangguh	POSCO	S. Korea	0.50	2008	2028
	Tangguh	SK-Power	S. Korea	0.80	2008	2028
	Tangguh	CNOOC	China	2.60	2008	2033
	Tangguh	Sempra	Mexico	3.70	2008	2027
MLNG	MLNG Satu	Tokyo Electric	Japan	4.80	1983	2018
	MLNG Satu	Tokyo Gas	Japan	2.60	1983	2018
	MLNG Satu	Saibu Gas	Japan	0.36	1993	2013
	MLNG Satu	Osaka Gas Co.	Japan	0.92	2009	2024
	MLNG Satu	Chubu Electric	Japan	0.54	2011	2031
	MLNG Satu	Saibu Gas	Japan	0.39	2013	2028

	MLNG Dua	Tokyo Gas	Japan	0.80	1995	2015
	MLNG Dua	Osaka Gas	Japan	0.60	1995	2015
	MLNG Dua	Kansai Electric	Japan	0.42	1995	2015
	MLNG Dua	Toho Gas	Japan	0.28	1995	2015
	MLNG Dua	Kogas	S. Korea	2.00	1995	2015
	MLNG Dua	CPC	Taiwan	2.25	1995	2015
	MLNG Dua	Tohoku Electric	Japan	0.50	1996	2016
	MLNG Dua	Shizuoka Gas	Japan	0.50	1996	2016
	MLNG Dua	Sendai	Japan	0.15	1997	2017
	MLNG Dua	Toho Gas	Japan	0.52	2007	2027
	MLNG Dua	Shikoku Electric	Japan	0.42	2010	2025
	MLNG Tiga	Japex	Japan	0.48	2003	2023
	MLNG Tiga	Tokyo/Toho/Osaka Gas	Japan	0.68	2003	2020
	MLNG Tiga	Kogas	S. Korea	1.50	2003	2010
	MLNG Tiga	Kogas	S. Korea	0.71	2004	2008
	MLNG Tiga	Tokyo Gas	Japan	0.34	2004	2024
	MLNG Tiga	Tohoku Electric	Japan	0.90	2005	2022
	MLNG Tiga	Kogas	S. Korea	0.40	2005	2008
	MLNG Tiga	Hiroshima Gas	Japan	0.08	2005	2013
	MLNG Tiga	Kogas	S. Korea	2.00	2008	2028
	MLNG Tiga	Shanghai LNG	China	3.00	2009	2034
Alaska (Kenai)	Phillips/Marathon	Tokyo Gas	Japan	0.31	1969	2009
	Phillips/Marathon	Tokyo Electric	Japan	0.92	1989	2009
Russia - Sakhalin	Sakhalin Energy	Tokyo Gas	Japan	1.10	2008	2032
	Sakhalin Energy	Tokyo Electric	Japan	1.50	2008	2030
	Sakhalin Energy	Shell Eastern Trading	Mexico/ USA	1.85	2008	2028
	Sakhalin Energy	KOGAS	S. Korea	1.50	2008	2028
	Sakhalin Energy	Hiroshima Gas	Japan	0.21	2008	2028
	Sakhalin Energy	Osaka Gas	Japan	0.20	2008	2028
	Sakhalin Energy	Toho Gas	Japan	0.50	2009	2033
	Sakhalin Energy	Kyushu Electric	Japan	0.50	2009	2029
	Sakhalin Energy	Tohoku Electric	Japan	0.42	2010	2030
	Sakhalin Energy	Saibu Gas	Japan	0.01	2010	2028
	Sakhalin Energy	Chubu Electric	Japan	0.50	2011	2026
Peru LNG	Peru LNG	Repsol YPF	Mexico	3.60	2010	2025
Abu Dhabi	Adgas	Tokyo Electric	Japan	4.30	1977	2019
Oman LNG	Oman LNG	Kogas	S. Korea	4.10	2000	2025
	Oman LNG	Osaka Gas	Japan	0.66	2000	2025
Qalhat LNG	Qalhat LNG	Itochu	Japan	0.70	2006	2026
	Qalhat LNG	Mitsubishi	Japan	0.80	2006	2021
	Qalhat LNG	Tokyo Electric	Japan	0.80	2006	2021
	Qalhat LNG	Osaka Gas	Japan	0.80	2009	2026
Qatar - Qatargas	Qatargas	Chubu Electric	Japan	4.00	1997	2022
	Qatargas	Tokyo Gas	Japan	0.35	1998	2022

	Qatargas	Osaka Gas	Japan	0.35	1998	2022
	Qatargas	Tohoku Electric	Japan	0.52	1999	2022
	Qatargas	Kansai Electric	Japan	0.29	1999	2022
	Qatargas	Tokyo Electric	Japan	0.20	1999	2021
	Qatargas	Chugoku Electric	Japan	0.12	1999	2022
	Qatargas	Toho Gas	Japan	0.17	2000	2022
	Qatargas II	ExxonMobil	UK*	7.80	2007	2027
	Qatargas II	Total	UK, Mex, France *	5.20	2008	2033
	Qatargas II	QP/ExxonMobil	US *	2.60	2007	2027
	Qatargas II	Chubu Electric	Japan	1.20	2008	2013
	Qatargas III	QP/ConocoPhillips	US*	7.80	2010	2030
	Qatargas IV	Shell	USA*	7.80	2010	2035
	Qatargas IV	Marubeni	Japan	1.10	2010	2035
	Qatargas IV	Mitsubishi	Japan	1.10	2010	2035
Qatar - RasGas	RasGas	Kogas	S. Korea	4.90	1999	2024
	RasGas (II)	Petronet	India	5.00	2004	2028
	RasGas(II)	Petronet	India	2.50	2009	2033
	RasGas (II)	Kogas	S. Korea	0.96	2004	2008
	RasGas (II)	CPC	Taiwan	3.00	2008	2033
	RasGas II	Petronet	India	1.20	2007	2008
	RasGas (III)	Kogas	S. Korea	2.10	2007	2026
	RasGas (III)	ExxonMobil	USA*	15.60	2010	2035

Yemen LNG	Yemen LNG	KOGAS	S. Korea	2.00	2008	2028
	Yemen LNG	Suez	USA*	2.55	2009	2029
	Yemen LNG	Total	USA*	2.00	2009	2029

Source: Gas Strategies Consulting

** - Although these volumes are targeted at the Atlantic basin, they are potentially flexible and culd be diverted to Asia. We believe that some small quantities have already been "remarketed" into Asia, with the Qatari project partners taking advantage of the liquidity of the US and UK markets in seeking to lock-in higher prices in favour of the market-based pricing of the US and UK*

We have assessed the projects to consider whether or not the contracts are likely to be renewed (if not to the exact buyers at the same level, to a buyer within the region). As a result of this assessment, we have identified a number of issues in terms of non-renewed contracts.

Dying Projects

Indonesia (Arun and Bontang)

Both of the existing Indonesian LNG plants, in Arun and Bontang, look highly unlikely to maintain their current levels of production. The Arun field, the sole source of gas for that plant, is in terminal decline with the existing contracts certain not to be renewed. Further, it currently does not produce enough gas to honour those contracts – one of the reasons the Asian supply/demand tightness is currently so acute. The issues at Bontang are slightly different, with the existing contracts unlikely to be renewed, with the gas being directed to the domestic market in Java in preference to further exports. Again, as with Arun, actual deliveries for the last few years (and for the future) have not met contractual levels. There are 12 mtpa worth of contracts up for renewal from Bontang in the period 2010-11 and latest indications from the Indonesian Government are that it will renew 3 mtpa from 2011 to 2015 and 2 mtpa from 2016 to 2020.

For the contracts that expire in the period beyond 2010/11, we have assumed the contract being renewed on a similar principle – e.g. c. 75% of the volumes are not renewed.

Alaska (Kenai)

Declining gas reserves for the plant means contracts from the Alaskan project are unlikely to be renewed although there has been agreement to extend the contracts for a further two years to the end of 2011 (subject to achieving a license extension for the facility in Alaska). Beyond that, we envisage the plant ceasing operations.

Questionable projects

A further group of projects face challenges in being able to achieve full contract extensions due the availability of sufficient gas reserves.

Malaysia

Gas Strategies understands that even now, Malaysia is struggling to produce enough gas for its facilities (a potential debottlenecking of the third element of the project – MLNG Tiga – is not able to proceed without further gas being identified for it). The level of renewals from the project (MLNG Dua contracts are due for renewal around 2015) will therefore likely be dependent on the success of the upstream companies finding new reserves before then. Gas Strategies thinks that there is a reasonable chance of gas being found for extensions to therefore occur – but perhaps not enough for everything to be renewed. With progress in technological solutions to monetising isolated gas reserves, we think it ought to be feasible for sufficient gas to be found to renew some but not all contracts in the long-run. We have therefore assumed no renewals for the Tiga contracts.

Brunei

There has been some speculation that Brunei, like Malaysia, may face gas supply issues in renewing its contracts. The challenge is slightly different in that the government has long exercised a policy of retaining significant reserves in the ground for future use, thus along with a mature basin, there is also the challenge of persuading the government to make sufficient volume available. However, BLNG's recent move to order two new 147,000 m^3 vessels to replace its aging 75,000 m^3 fleet, described as "part of a rejuvenation process where we are preparing to ship LNG for another 20 years up to 2033" suggests it is confident of achieving full renewals.

New projects

B.1 Project Maturity

The Project Maturity Index measures the extent to which the project is close to becoming a firm project. The Maturity Index awards a binary score (0 or 1) for each of the main steps towards project launch. These are:

- Confirmation of gas availability – in that reserves are firmed up or the appropriate supply contract has been signed
- Formation of an aligned project consortium/Declaration of Intent to proceed without partners
- Award or completion of a FEED Study
- Conclusion of Sales Agreements, including MOUs and LOIs.
- The taking of a Final Investment Decision to proceed with the project.
- Political support for the project (either internal or external)
- Viable costs/economics.
- Project type – expansions are favoured over greenfield projects
- Whether or not there are experienced partners present
- Whether or not there are "significant firsts" in the project (e.g. floating, small scale CBM)

We have considered all of the known Asia Pacific and Middle Eastern projects under development in this exercise.

	roject structure Agreed / Partners aligned	EED Study Underway / Completed	D Taken/ EPC Awarded	rm Gas Reserves/Supply	ales Agreed	litical Support	ost/ Economics	roject type (Greenfield=G; Expansion =E)	Experienced partners?	No “significant Firsts”	Maturity Index	Total Capacity (Mtpa)	GS estimated start-up
						“Probable”							
Indonesia - Sengkang (Energy World)	1	1	1	1	0	1	1	G	0	0	6	2.0	2011
Gorgon	0	1	0	1	1	1	0	G	1	1	6	15.0	2014-15
“new” Qatar	0	0	0	1	0	1	1	E (1)	1	1	6	15	2015/16
Sakhalin Train 3	0	0	0	1	0	1	1	E (1)	1	1	6	4.8	2014
PNG - Liquid Niugini Gas	1	1	0	0	1	1	0	G	0	1	5	9	2015-6
Gladstone (BG)	1	0	0	1	1	1	0	G	1	0	5	3.0	2014
Tangguh Train 3	0	0	0	0	0	0.5	1	E (1)	1	1	4.5	3.8	2013
Sunrise/Darwin 2	0	0	0	1	0	0.5	0	E (1)	1	1	4.5	6	2016
						“Possible”							
Browse	0	0	0	1	0.5	1	0	G	1	1	4.5	10	2017-18
Gladstone (Sunshine)	1	0	0	1	0	1	1	G	0	0	4	0.5	2013
More “new” Qatar	0	0	0	1	0	0	1	G	1	1	4	15	2018
Pilbara/Scarborough	0	0	0	1	0	1	0	G	1	1	4	6.0	2016
Wheatstone	1	0	0	1	0	0	0	G	1	1	4	5.0	2014
Donggi-Senoro	1	1	0	0	0	0	1	G	0	1	4	2.0	2013
Pars LNG	1	1	0	1	0	0	0	G	1	0	4	10	2018/19
Persian LNG	1	1	0	1	0	0	0	G	1	0	4	16	2015/16
PNG - Exxon	1	0	0	1	0	0	0	G	1	1	4	6.3	2014
Ichthys	0	0	0	1	0	1	0	G	1	1	4	7.6	2016
						“Speculative”							
NIOC/Iran LNG	1	1	0	1	0	0	0	G	0	0	3	10	2021/22
Gladstone (LNG Ltd)	0	0	0	1	0	1	1	G	0	0	3	1.3	2013
Gladstone (Santos)	1	0	0	1	0	1	0	G	1	0	3	5	2016
Gorgon expansion	0	0	0	1	0	0	0	G	1	1	3	10.0	2017
Marsela (Inpex)	0	0	0	1	0	0	0	G	1	1	3	6	2016
Iran - Qeshm LNG	1	0	0	0.5	0	0	0	G	0	0	1.5	3.5	2012
PNG (LNG Ltd)	0	0	0	0	0	0	0	G	0	0	0	2	2020

Source: Gas Strategies Consulting

The index only tells part of the story and is not a reliable guide to when a particular project will proceed but it does give some guide to progress. It will be noted than none of the projects (except Senkang) approaches a full score. Of the 22 projects identified almost all have a significant problem and some have more than one.

The following are "high cost":

Gorgon

Browse

Pilbara

Icthys

PNG Exxon ($10 – 13 billion 6.3 mtpa)

PNG LNG

Gladstone LNG (all)

These are using new technology:

Gladstone (all)

Sengkang

Darwin/Sunshine (floating)

The following have only inexperienced partners:

Sengkang

Liquid Niugini Gas

Gladstone (sunshine)

Gladstone LNG

Marsela

PNG (LNG Ltd)

The following are in politically difficult environments:

PNG (all)

Iran (all)

Sakhalin Train 3

Darwin/Sunrise

To characterise the projects better we have reviewed each one individually.

Project Reviews

<u>Probable Projects</u>

Australia – Gorgon

The Gorgon LNG project has been around since the 1970s, and indeed serves to highlight one of the common features of LNG projects – namely moving from the identification of reserves to actual production. Gorgon currently faces two major obstacles. Firstly, the costs associated with the project are understood to be extremely high, with current commodity and contractor rates exacerbated by the high cost of labour in Australia and the specific challenges of the Gorgon project. The high costs have persistently caused delays to the project start date – with the project having been effectively on the brink of FID for some time now. The most recent move to overcome the problem was to scale-up the project's size to 15 mtpa – and a subsequent announcement of no FID before 2010. Although this project seems to have much going for it (including agreed sales deals for the off-take), its history suggests it needs to be watched with some trepidation.

"New" Qatar expansion

Qatar's enormous reserves and rapid LNG expansion mean it is clearly a strong candidate for future supply of LNG. However, Qatar has placed a moratorium on future gas developments until 2010 (the pace of development over last few years has been extraordinarily rapid and has contributed to escalating costs. Although reserves are immense, Qatar wants to take stock of impact of development so far and review policy for the future), we feel it is likely that increased LNG developments will commence once the current activity has subsided. There may be some political opposition to such a development but the cost is likely to be relatively low, the gas is there and Qatar Petroleum will likely have little trouble finding partners if it feels the need to. It is a well established machine for developing LNG so as soon as moratorium lifted new developments could be rolled out.

Russia – Sakhalin Expansion

An expansion project, as a rule, is easier and lower cost than a greenfield one. Many of the political, developmental and partnership issues having already been resolved. The Sakhalin region clearly has the gas reserves and expansion here is likely to be determined by the will of Gazprom. The gas would likely come from the Sakhalin-2 area. The project has not announced its intention to go ahead with a third train but is known to be considering it. However, it does not want to the distraction of working on an expansion before the first phase is on stream. This has suffered from delays, political problems and serious cost over-runs. The most likely impediment to further developments is the high cost environment of the moment.

Indonesia - Sengkang (Energy World)

Another new Indonesian project, Energy World Corporation (EWC) has appointed Arup to provide LNG storage, ship loading, maritime and civil engineering services for the proposed Sengkang LNG liquefaction facility to be built in Sulawesi. Built from four 0.5 mtpa modules, the project is a pioneering example of small-scale, modular LNG. The trains are being built by Chart Energy & Chemicals and they will be skid-mounted and moved to the construction site. Current resources at Sengkang are 583 Bcf of gas, however EWC believes it has 5-7 Tcf of reserves that could sustain production of between 5-7 mtpa of LNG for 20 years. The partners target end-2009 for operations and although optimistic, its ability to use non-LNG specialist contractors (here using concrete tanks) means it could begin construction relatively quickly. No details are available on potential customers for the LNG or on whether the terminal is actually under construction, although engineering contracts have been let and equipment is being ordered.

Indonesia – Tangguh Expansion

As with Sakhalin, and expansion of Tangguh seems a relatively straightforward option for future supply. However, it faces a number of potential hurdles. The Indonesian government has expressed its desire to influence the behaviour of IOCs in the country – with demands that gas been made available for the domestic market. As such, BP (the project leader) would likely seek to ensure any further development will be economically viable for them. Furthermore, although gas reserves are believed to be adequate for an expansion, further appraisal activity will likely be needed. Were these issues to be overcome satisfactorily, an expansions seems a viable option for the project. The major issue with the project would seem to stem from the dysfunction and divided command of the Indonesian authorities with BPMigas, Pertamina, Energy Ministry and Finance Ministry all with different agendas. That said, as an expansion, and with gas supply unlikely to be an issue, its chances must be relatively good.

Australia - Gladstone (BG, Queensland Gas)

The presence of major LNG player in this project adds a degree of gravitas not only to the project but indeed to the concept of coal bed methane as a source of LNG supply into the future. The A$8 billion project was only announced in early 2008 but is already very well formed in terms of shareholder agreements. BG is to buy all of the 3-4 mtpa of LNG output for 20 years and with its global reach ought not to be troubled with ensuring that LNG finds a market. However, the use of coal bed methane as feedstock for an LNG plant is new and there is clearly potential for the, already very high, cost estimate to get out of hand and cause postponement or cancellation of the project. Even at current estimates it will need a delivered price in excess of $7/mmBtu to be viable.

PNG - Liquid Niugini Gas

Liquid Niugini Gas is a joint venture of Interoil, Merrill Lynch and Pacific LNG. It has a partners agreement signed and at the end of February 2008 signed a FEED contract with Bechtel as well as selecting the same company as the EPC contractor. Merrill Lynch has agreed to take all of the LNG from the first two trains of the project, thus securing a sales agreement. Furthermore, the PNG Prime Minister, Sir Michael Somare, has expressed his support for the project. Merrill Lynch is leading the financing strategy for the project,. The main hindrances to the development of the project would seem to be ensuring costs can be kept to an acceptable level and ensuring a secure supply of gas is available. Interoil has the Elk field in PNG, with estimated recoverable reserves of 11 Tcf. It is currently continuing to appraise the discovery. The ultimate cost and therefore economic viability of the project will likely be tied to the cost of developing the gas reserves and as such, its economic viability is not yet fully clear. Although targeting a "fast-track development" (by 2012), such progress would be spectacularly fast and we would not expect start up before 2015-6. The project is being promoted by inexperienced partners and Merrill Lynch ahs no direct experience of selling in the Pacific market. Although the premier has voiced his support, there is a long way between this and signing of the necessary government agreements; PNG does not have a good track record of doing this.

Possible Projects

Australia – Browse

Although Woodside has been actively marketing gas from the Browse project – supply deals have been signed with CPC of Taiwan and PetroChina, with Singapore linked as a third potential customer – it still faces the prospect of securing gas supplies from its WA1P upstream partners – including BP, BHP Billiton, Shell and Chevron (and probably, in reality having them as partners in the development). Although FEED appears to have been awarded for the upstream development, the gas is in very deep water and will likely prove very expensive to produce. It wants to take FID in 2010 but is still arguing about Burrup vs. Kimberley as a site for the liquefaction plant with the West Australian government seeking a single common user facility for all Browse basin reserves. Two further customers are likely needed for the 10 mtpa plant. As such, Woodside itself does not see production before 2013-15 and a delay beyond that would not be unexpected. As with all Australian projects, cost is an issue, particularly with fields in deep water and distant from land although it is understood the project has succeeded in securing relatively high-priced deals with CPC and PetroChina, approaching oil parity.

Australia - Gladstone (Sunshine)

Another relatively recent, Queensland, CBM, mid-scale LNG project is this one, being driven by Sojitz and Sunshine Gas. Still at a very early stage, the partners appear to have reached agreement and have access to Sunshine's CBM production. Sojitz will also potentially bring access to the Japanese market but at this early stage of development, the project rates only as possible. The estimated cost of US$500 million for 0.5 mtpa is reasonably high compared to the other mid-scale plant (LNG Ltd) but relatively cheap compared to the larger projects being developed in Australia. None of the partners has LNG experience, and as the technology, both for small LNG projects and for the use of coal bed methane as a feed gas is untried, the project has real obstacles to overcome.

Australia – Sunrise/Darwin 2

The Greater Sunrise gas prospect lies between Australia and East Timor and was previously the subject of a border dispute between the two countries. The resolution, that it was placed in a "Joint Petroleum Development Area" with the revenues split between the two. The potential requirement for East Timor co-operation (or even a site for the plant) means it faces some political and developmental hurdles. The project is also vying with Browse to be the next project developed by Woodside. The two projects will not be developed at the same time, but it is currently difficult to see which will go first.

Its remoteness from Australia has also caused issues, with project partners (Woodside, Shell, ConocoPhillips, Osaka Gas) differing on the best way to liquefy the gas – piping it the 530 km to Australia or using as-yet untried floating liquefaction. Ironically, Woodside recently said that the floating solution looked the cheapest – a volte-face compared to 2004 when such an options (pushed by Shell) was the most costly). ConocoPhillips would likely favour the pipeline option to the existing Darwin project site (in which it is a partner). This disagreement has now gone on for the best part of a decade. If it could be resolved and the Timorese government pacified the project should have a reasonable prospect, particularly as an expansion of Darwin.

Australia – Pilbara/Scarborough

Pilbara LNG was a project initiated by BHP Billiton in the early 2000s ago, tapping its Scarborough reserves, held with ExxonMobil. Until mid-2006 however, ExxonMobil was not interested in developing the field. It now seems to be open to the idea, but work will undoubtedly need to be done to shore up the project partnership – with ExxonMobil yet to be convinced there is an economic means of developing the reserves – in 900 metres of water 300 km offshore and with little or no condensate. Although the gas resources seem to be there (10 Tcf estimated), the project is at a relatively early stage of development and the partners have other LNG projects in Australia that they may prioritise. No project company yet exists and the associated costs are likely to be high. Once again, as with other Australian projects, cost, priority (of the partners) and the crowded list of opportunities means it will likely have to wait its turn.

Australia – Wheatstone

Chevron's Wheatstone project has only been announced for less than a month and is based on the field of the same name, discovered in 2004. At such an early stage of development, details are very sketchy. One advantage is that as a 100% Chevron project, partner agreement may be easier to come by. It not likely to be so extravagantly high cost as many Australian projects as the field is in shallower water and is nearer land. No Autralian project is low cost, however. FEED is not expected until 2009 and as such. The project looks unlikely to be operational before 2015.

Australia – Ichthys

A joint venture between Inpex (76%) and Total (24%), this project recently had its timeline delayed until "at least 2013" but with no confirmed timetable, its realistic timing is uncertain. Equally, no decision has yet been made on where to construct the liquefaction plant for the offshore field. Sites in Western and northern Australia are still being considered. With an uncertain project timetable and the same cost issues as for other Australian projects, this remains uncertain.

Australia - Gladstone (Santos)

A project based on the use of coal bed methane (CBM) from Queensland, eastern Australia is being pursued by Santos. A relatively recent development, the project has nonetheless moved quite quickly – benefiting from a single company being invoked. As with many of the other Australian projects, the cost is likely to extremely high (Santos estimates A$5-7 billion for the 3-4 mtpa plant) and thus securing sales contracts that ensure its economic viability will be key. Although it pursuing a 2014 timeframe to start production, realistically, we expect it to be later than that.

Indonesia – Donggi

A 2 mtpa plant planned for Sulawesi Island, based on the Matindok and Senoro fields. Mitsubishi has been selected as partner for Pertamina in developing the project. Bids from EPC contractors have been received – with the project cost reported to be $1.3 billion. It is expected that the LNG will be marketed to Pertamina's existing customers in Japan (Kansai and Chubu) although there have also been suggestions that the LNG will be used to satisfy gas demand in Indonesia (via new LNG terminals on Java) if a pipeline is not built from Bontang. Start-up could possibly be in 2012, but more likely later, with current rumours of a delay due a dispute over the price to be paid for the feed-gas. It would be a brave person to back increased Indonesian LNG production too strongly but with the advent of economically viable small and medium scale LNG projects, a project such as this may be feasible. Mitsubishi has been awarded the EPC to construct the terminal but until all of the outstanding issues have been ironed out, it remains a distance form FID. Given the tumultuous political situation in Indonesia (with respect to gas exports particularly) this project will remain a possible until more firm progress is made.

PNG – Exxon

The second LNG project in PNG is being backed by ExxonMobil (41.6%), Oil Search (34.1%), Nippon Oil (1.8%), Santos (17.7%), AGL (3.6%) and MRDC (a PNG company representing landowner interests – 1.2%). The project has the advantages of a heavyweight partner as well as a Japanese partner that might be able to enhance marketing opportunities. It faces challenges however, not least of cost, with the gas located in the PNG highlands. The partners have signed a Joint Operation Agreement. The project will be fully integrated with the above shares throughout the value chain. ExxonMobil will market the LNG on behalf of the project. However, fiscal terms have not been reached with the government of PNG and as such, FEED has not yet been initiated.

Iranian projects

All the major Iranian projects have a number of things in common: 1) there is no shortage of accessible gas (South Pars); 2) a relatively long history; and 3) massive political obstacles.

NIOC/Iran LNG is 100% owned by National Iranian Oil Company (NIOC), and is thought to be 10 mtpa. OMV has had some dealings with the project with the prospect of joining it.

Persian LNG is a partnership between NIOC (50%), Shell (25%) and Repsol from (25%) and is 16 mtpa in size. Shell and Repsol will market the first train with an office reportedly established in Tokyo for the second.

Pars LNG is a 10 mtpa JV between NIOC (50%), Total (40%) and Petronas (10%). Total and Petronas will purchase LNG from Train 1. India, Thailand and China are possible markets for train 2

All of these projects would be feasible but for a few issues. There has never been full political commitment towards LNG in Iran (unlike Qatar) with different political blocs favouring different uses for the country's vast gas reserves. It is reluctant to allow International companies access to its reserves on acceptable terms; buy-back contract, rather tha production sharing deals are all that Iran appears prepared to offer.

Further, its international political standing and security issues mean it has proved difficult for foreign companies to operate there. In the LNG context, the sanctions against it mean that established LNG technology cannot be used there (the licenses are American). Nor can the LNG be sold into the liquid US market.

Cost of development may also be an issue with a recent dispute between Total and NIOC over the increased costs of the Pars LNG plant.

The capacity for Iran to become a major LNG producer is one of the great unknowns in the LNG world. A strong development would have the capacity to shift the supply/demand balance significantly, assuming the LNG were able to be sold to enough countries.

More new Qatar

Qatar's potential to increase its LNG production means that even further expansion ought to be considered as possible rather than speculative.

Speculative

Australia - Gladstone (LNG Ltd)

One of four LNG projects in Queensland seeking to develop CBM into LNG. LNG Ltd will buy gas from Arrow Energy and export from Fisherman's Point. LNG Ltd is developing a number of small to mid scale LNG facilities around the world but is not therefore yet a proven developer/operator. One thing in the project's favour is the apparently low cost – estimated at US$400 million for the initial 1 mtpa of production. This low cost is partly due to the small-scale, modular nature of the project – something which also shortens the construction time (to 24 months). The project's target date is end-2010 although with LNG Ltd understood to be seeking partners for the project as well as sales contracts and until any sort of engineering contracts signed, the project must only be considered a possible project. This suffers from teh same problems as the other Queensland coal bed methane projects.

Other Iranian projects include another LNG Ltd project – Qeshm LNG – which faces many all the problems as above but without some of the challenges (being small scale), but using an unproven technology. That said, the project may lack the clout of the larger companies involved in the others. Future developments such as from **North Pars** (where CNOOC has signed a development deal with NIOC) or the **Golshan and Ferdowsi Fields** (in which a similar deal has been done with SKS Ventures of Malaysia) may offer longer-term opportunities but only if the developmental issues that have dogged the country's LNG industry so far can be overcome.

Indonesia - Marsela (Inpex)

Inpex's second LNG project in the region (after Ichthys) at the moment it is little more than a gas find (believed to be able to support 6 mtpa of LNG production). Partners are being sought and Inpex is understood to be investigating a floating production solution. Timing looks likely to be beyond 2015, with Ichthys remaining the priority development.

Australia – Gorgon expansion

Reserve levels in the Gorgon area mean an expansion ought to be possible in the future – assuming the first element of the project ever get going.

PNG (LNG Ltd)

The smallest, and least developed, of the PNG LNG projects is being pursued by LNG Ltd. Still at a very early stage (feasibility study), this project remains nothing more than speculative for now, particularly given the competition for reserves from the other prospective LNG projects.

Conclusions

Most of these projects will fail to achieve their targeted start dates and we, to the best of our ability, have to assess when they might occur. As highlighted above however, such developments rarely run as expected. What is clear, is that there is a plethora of new projects in the region – more than enough in fact to cope with projected demand. The ability of these projects to develop in a timely manner will largely influence the relative supply tightness in the 2015-20 timeframe. Some of the projects, notably the Australian ones, are likely to be very high cost projects and will struggle to develop in the current market. Others, such as the Iranian projects, face massive political hurdles which must be overcome if their potential is to be realised and which will really require a major geopolitical shift.

For our central case we then make probabilistic estimates of the likely range of start dates for each project and the chance of it not proceeding at all. These estimates are then submitted to a Monte Carlo analysis to achieve a supply profile.

The data for each project is set out in the following table:

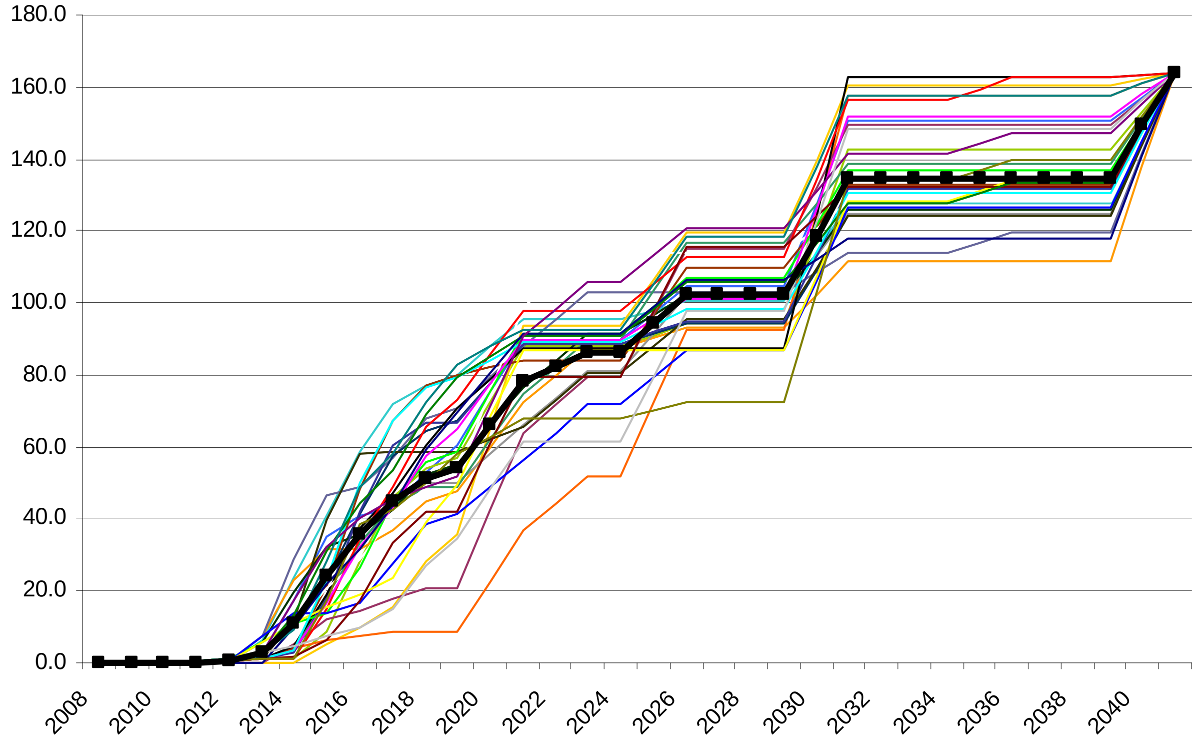
Exhibit Table 25 Potential Start Dates

	Earliest Date	Most Likely	Latest Date	Total failure %
Indonesia - Sengkang (Energy World)	2011	2012	2015	2
Gorgon	2014	2025	2035	15
“new” Qatar	2014	2015	2020	15
Sakhalin Train 3	2014	2017	2025	5
PNG - Liquid Niugini Gas	2013	2016	2025	10
Gladstone (BG)	2014	2015	2030	20
Tangguh Train 3	2013	2015	2020	5
Sunrise/Darwin 2	2015	2018	2025	10
Browse	2015	2030	2040	15
Gladstone (Sunshine)	2014	2020	2040	30
More “new” Qatar	2016	2018	2022	15
Pilbara/Scarborough	2017	2030	2040	15
Wheatstone	2014	2017	2030	10
Donggi-Senoro	2014	2020	2030	10
Pars LNG	2020	2030	2040	20
Persian LNG	2020	2030	2040	20
PNG - Exxon	2014	2020	2030	15
Ichthys	2017	2030	2040	15
NIOC/Iran LNG	2020	2030	2040	20
Gladstone (LNG Ltd)	2014	2020	2040	30
Gladstone (Santos)	2014	2015	2030	20
Marsela (Inpex)	2016	2025	2035	20
Iran - Qeshm LNG	2020	2030	2040	20
PNG (LNG Ltd)	2016	2030	2040	20

Source: Gas Strategies Consulting

The results of the Monte Carlo runs are shown in the following figure:

Exhibit Figure 14 Supply outputs from Monte Carlo runs



Source: Gas Strategies Consulting

To generate a low supply case we include only those projects we view as "probable" i.e. which are well advanced and have no serious obstacles. These are largely expansions with the exception of the Niugini project.

For a high case we allow all projects to proceed on their earliest achievable time frame.

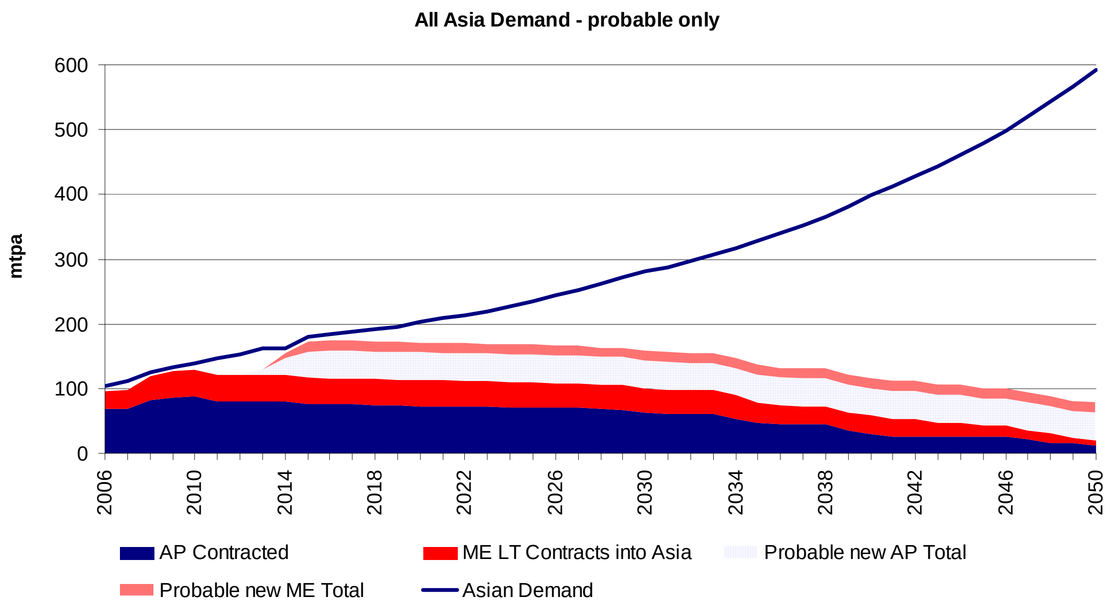
These give a measure of potential supply availability. In reality the market has several feedback mechanisms that tend to keep it in balance. The first is that projects will generally not proceed without firm contracts. If too many are trying to come to market at the same time some will be delayed. In addition, Middle East projects, such as Qatar can easily access European and US markets if they find Asian contracts hard to find and thus remove themselves from the supply picture.

Equally if the market risks being short Qatar, BG and some other suppliers are in a position to divert flexible US and UK supply to Asia, either spot or on a long term basis.

B.2 Supply and Demand Scenarios

To show the range of possibilities for the supply and demand balance for LNG in Asia we have overlaid our three supply scenarios on our demand projections as follows:

Exhibit Figure 15 All Asia demand – Probable only

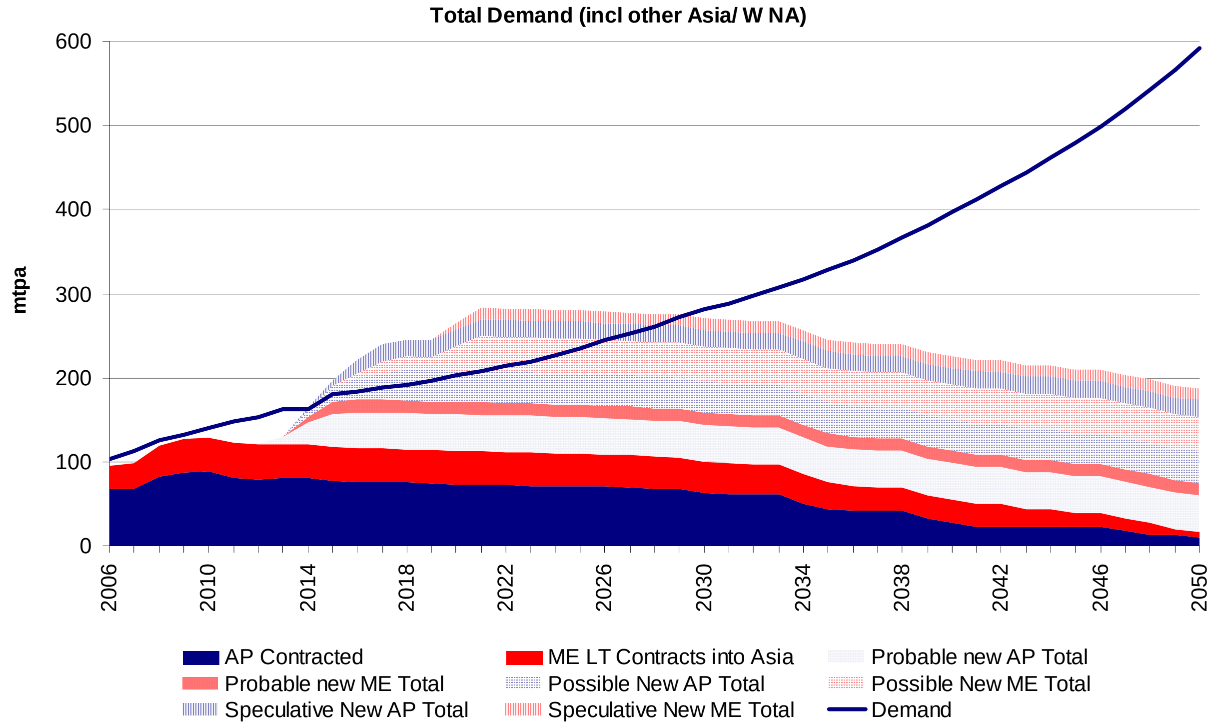


Source: Gas Strategies Consulting

Exhibit Figure 15 shows the demand for the main markets against our "probable" supply coming forward at its projected dates. This picture is significantly short of supply except for a brief period in the middle of the next decade. In reality we should also take account of the American west coast market and the emergence of small new markets such as Singapore. When this demand is added the picture becomes even more supply constrained.

On the other hand if all the proposed projects were to go ahead on the dates they project, ignoring the need to obtain sales contracts, there would be a large supply surplus starting from about 2014 and lasting for more than a decade.

Exhibit Figure 16 All Asia & W North America demand – all proposed projects

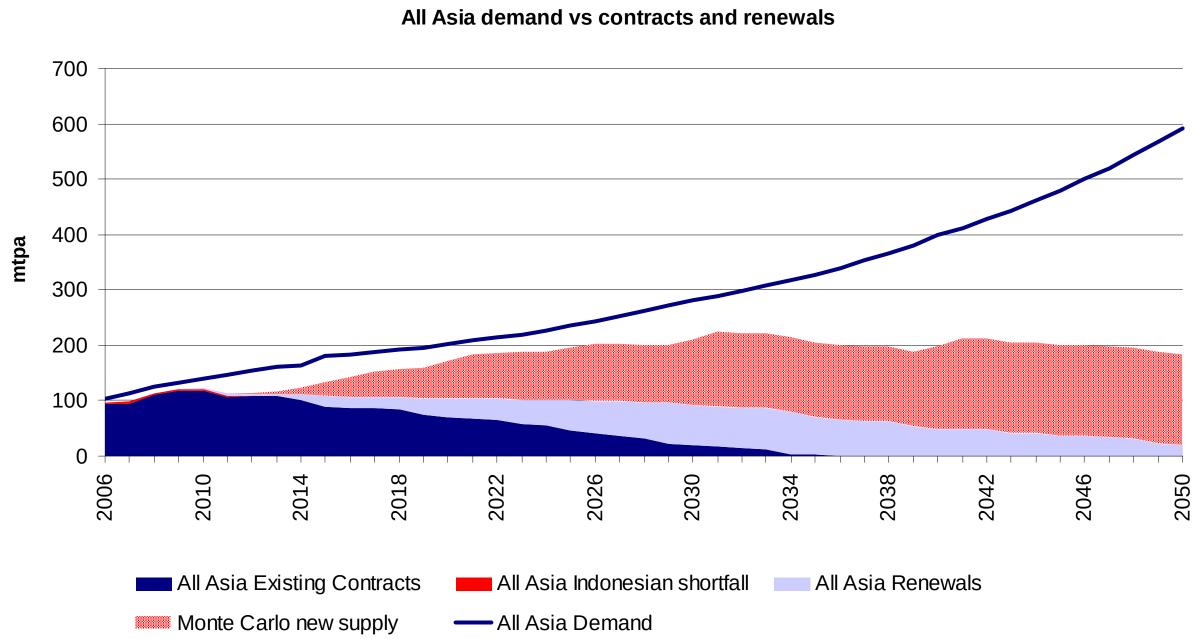


Source: Gas Strategies Consulting

This does indicate that there is, in theory, the potential for a highly competitive supply picture which would lead to our low case pricing scenario.

Our central case using the Monte Carlo generated supply shows a more balanced picture.

Exhibit Figure 17 All Asia demand – Monte Carlo supply



Source: Gas Strategies Consulting

This has a shortfall of around 30 mtpa in the period during which Alaskan LNG would be coming to market, although this is more than covered by available flexible supply that could be diverted from the Atlantic Basin. Nevertheless it represents a plausible opportunity for Alaskan LNG to enter the market at that time.