# 2015-2035 LNG Market Assessment Outlook for the Kitimat LNG Terminal

**Prepared for: KM LNG Operating General Partnership**

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## Introduction

KM LNG Operating General Partnership ("KM LNG"), a subsidiary of Apache Canada Ltd. ("Apache") is applying to the National Energy Board for a license to export up to 10 MMt/y of LNG over the period of 2015 to 2035 ("the Proposed Export"). Natural gas produced in Canada will be liquefied at the proposed LNG terminal to be located at Bish Cove near Kitimat, British Columbia and from there exported and transported by tanker ships to markets primarily in Asia Pacific. KM LNG retained Poten & Partners Inc. ("Poten") to provide a written independent assessment of the LNG demand in the international market relevant to KM LNG.

Poten has assessed this issue by identifying primary markets and potential competing supply to KM LNG. Consideration was also given to the pricing scenarios and an assessment of the overall viability of KM LNG.

## Executive Summary

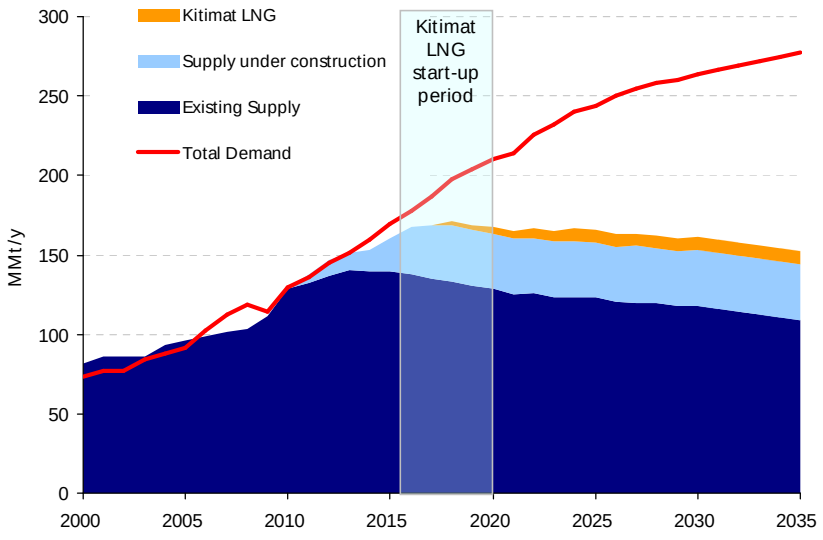
Global liquefied natural gas ("LNG") demand has doubled to more than 200 million tonnes per annum (MMt/y) over the last ten years due to strong natural gas use in power generation. This trend is expected to continue to drive long-term LNG demand growth. Global LNG demand is expected to outstrip the supply projects that are currently operating or under construction. New liquefaction projects have to be developed in order to sustain the aggressive growth in global demand.

The Pacific basin offers great opportunities to KM LNG. The Asia Pacific Market is characterized by LNG buyers entering into long-term supply contracts (i.e. 20 years plus) as buyers are concerned with security of supply, and sellers insist on firm commercial arrangements to underpin project economics and financing arrangements. Japan, South Korea and Taiwan (JKT) accounted for more than 54% of global trade and 86% of Asia Pacific trade in 2009. The JKT markets lack indigenous resources and large pipeline import connectivity and therefore are heavily dependent on LNG. Security of supply is a key driver in these countries' procurement strategies. In addition to these traditional markets, the Asia Pacific Market includes the emerging markets of China and India and smaller new importers such as Thailand, Singapore and Pakistan which are regarded as niche markets.

LNG demand is expected to grow in Asia Pacific by an average of 2.70% annually during the 2014-2035 period. This steady growth will cause a supply deficit post 2015 if no additional export projects develop. Poten projects that such a supply demand gap will grow from around 9 MMt/y in 2015 to reach 47 MMt in 2020, 85 MMt in 2025, and 130 MMt in 2035.

KM LNG is well placed to fill some of this gap and gain market share in this premium Asian market. The project's potential production of up to 10 MMt/y would represent at most 8% of the forecast gap in 2035[1].

**Figure 1: Asia Pacific Supply Gap Develops Post 2015**




[1] Gap in Figure 1 is between the total Pacific Basin LNG demand and existing/under construction supply projects in Asia Oceania and the Middle East targeting Asian markets. For only the key markets analyzed in this study (JKT and China), the gap between LNG demand and contracted supply is shown on Figure 4, Page 8 and amounts to 24 MMt in 2015, growing to 118 MMt in 2025.

There is currently a significant number of competing LNG supply projects being planned in Australia that target the Asia Pacific market, but only about 30% are likely to be completed within the time period KM LNG is targeting due to economic, political and Engineering, Procurement and Construction (EPC) cost constraints. KM LNG is a natural choice to provide additional supply to the Asian markets to cover part of the emerging supply gap.

Canada exhibits large natural gas resources, and is well located in proximity to the major LNG buyers Japan, Korea, Taiwan and China. LNG buyers may welcome the opportunity to diversify their supply sources, particularly in light of Canada's political stability and regulatory certainty. KM LNG also has strong equity players in the liquefaction project, with considerable reserves and supply available to be committed to the plant and clear strategic alignment towards monetization through LNG. There is a significant opportunity to capture long-term market share for suppliers that demonstrate a strong likelihood of successful start up during the 2014-2018 period.

LNG sold under new long-term supply contracts to the Far East is currently priced around 90% of oil on an equivalent heating-value basis. Asian oil indexed prices are well above gas-on-gas prices in North America. The high prices for LNG reflect the geographic isolation and scarce indigenous energy resources of the traditional Asian LNG buying countries, and China's large appetite for energy resources. Far Eastern buyers have an overriding concern with security of LNG supply as compared to price sensitivity, as they generally lack alternative sources of gas. Consequently, they are willing to pay a premium for a reliable supply source.

Poten expects that prices for long-term LNG supply contracts will continue to be robust, both because oil prices will remain high and also because contractual formulas will continue to price LNG at close to oil parity. Nonetheless, there is some potential for Asian LNG prices to drift lower over time. Through 2015 Poten estimates that ex-ship LNG prices for Far Eastern markets will be between $12 and $18 per million British thermal unit (MMBtu). For the longer term we retain our top-end at $18 per MMBtu (in constant 2010 dollars) but lower our bottom end to $9.50/MMBtu.

## Primary Markets

### *Key findings*

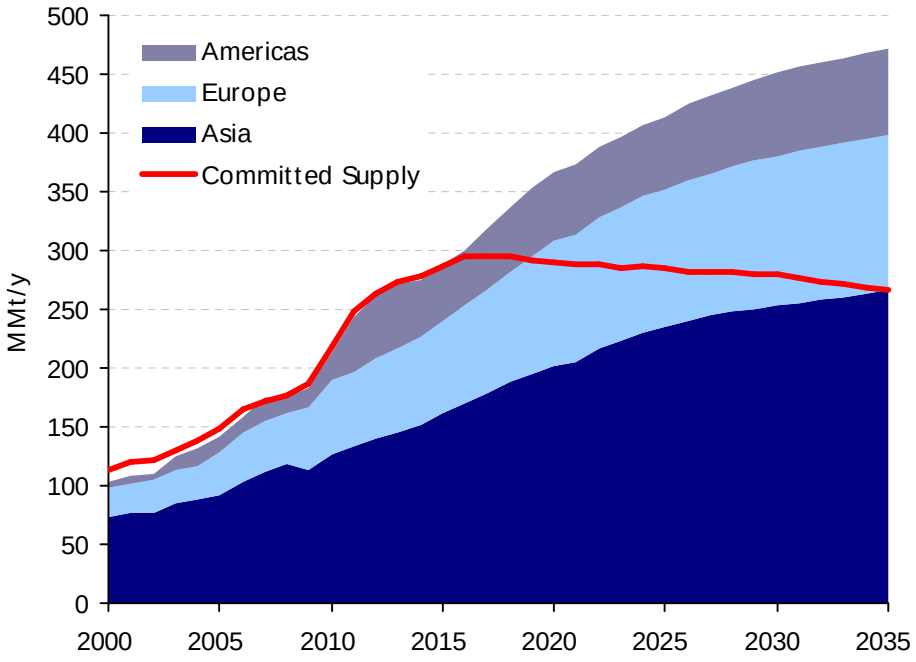
- The Pacific Basin is the natural market for KM LNG.
- The Asia Pacific Market is one characterized by LNG buyers entering into long-term supply contracts (i.e. 20 years plus).
- Security of supply is a dominant concern for traditional Asian buyers.
- Strong LNG demand growth expected in Asia Pacific driven by gas use in power generation. This is particularly true for China, Japan, South Korea and Taiwan.
- LNG demand is expected to grow in Asia Pacific an average of 2.70%/y during the 2014-2035 period.
- There is an immediate need for additional long-term supply contracts to cover growing demand in Japan, Korea, Taiwan and China. The aggregate gap between long-term contracts and forecasted demand in these countries becomes critical starting around 2015, which is the period when KM LNG is projected to come on-stream.
- Japan, Korea and Taiwan are heavily dependent on LNG as they lack indigenous resources and large pipeline import connectivity. To ensure no disruption to economic growth and stability, these countries have in the past, and continue today to seek long-term (20+ years), diverse and secure LNG supply contracts. Demand for LNG is therefore inelastic.
- While China does have some of its own indigenous resources, due to its projected economic growth, it too seeks long-term, diverse and secure LNG supply.

## *The Global LNG Market*

The LNG trade has grown rapidly over the last decade. In 2000, the global LNG demand stood at around 100 MMt/y. By 2010, LNG demand had doubled to more than 200 MMt/y. Despite the current situation of short-term oversupply, strong natural gas use in power generation will continue to drive long-term LNG demand growth. The less carbon-intensive emissions profile of natural gas as compared to competing energy sources such as oil and coal is expected to further increase the demand for LNG. As new upstream development gets geographically further away from prospective markets, LNG also is projected to take an increasing proportion of natural gas trade. Liquefaction drastically reduces the volume of natural gas per unit of heating value, making it the most efficiently way transport natural gas over very long distances. We project the global LNG trade to reach more than 360 MMt/y by 2020, 400 MMt/y by 2025 and 470 MMt/y by 2035.

As shown in the graph below, global LNG demand is expected to outstrip the supply projects that are currently operating or under construction. The wedge of demand that must be met by new LNG projects increases rapidly from 2016, to reach more than 125 MMt/y by 2025.

**Figure 2: Global LNG Demand to Resume Growth Post 2009***



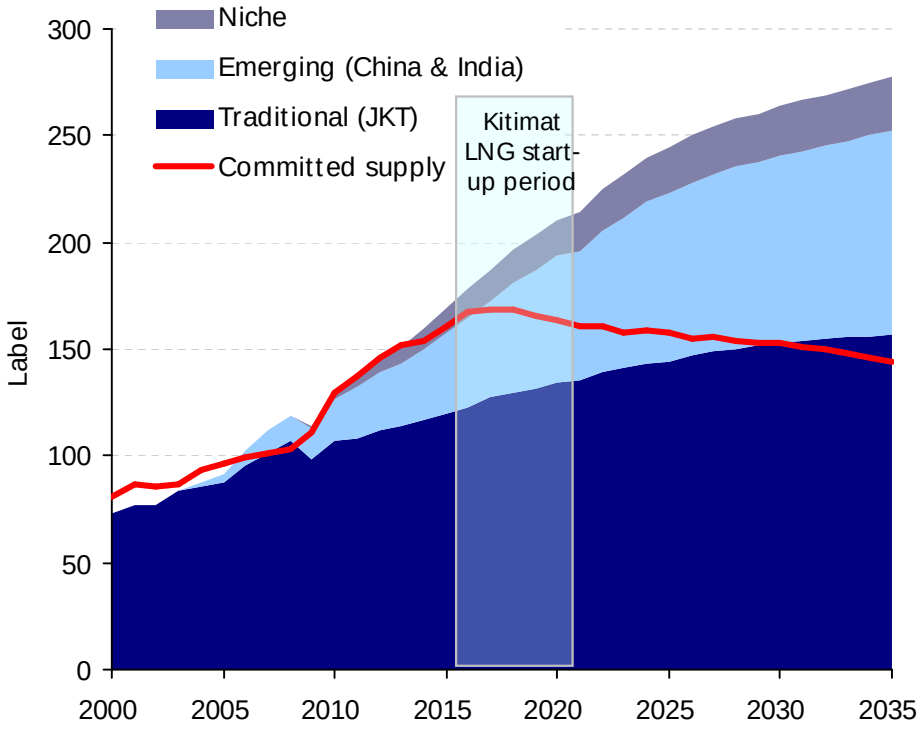

**Committed Supply: Existing export projects + Export projects under construction*

## *Asia Pacific Markets*

The Asian LNG market is predominantly based on long-term supply contracts. In 2009, more than 95% of total LNG deliveries were under such long-term contracts. Long-term contracts are the norm in order to address both buyer concerns with security of supply risks, and sellers' insistence on firm commercial arrangements to underpin construction and operation of LNG liquefaction facility economics, including financing arrangements. Unlike the Atlantic basin, there are no liquid gas markets to provide a ready fall back market for buyers or sellers.

The Asia Pacific market is comprised of three distinct segments, the traditional markets of Japan, Korea and Taiwan, the emerging markets of China and India, and niche markets, smaller new importers such as Thailand, Singapore, Chile, and Pakistan. For the Asian market as a whole, committed supply is a real and growing concern with a tight balance through 2012, and emerging wedge of needed new supplies starting in 2014.

**Figure 3: Pacific LNG Demand Outstrips Committed* Supply**




** Committed Supply: Existing export projects + Export projects under construction*

Until recently, Asia Pacific LNG demand comprised three markets: Japan, Korea and Taiwan. In 2009, JKT accounted for more than 54% of global trade and 86% of Asia Pacific trade. Even accounting for current economic conditions, Poten projects the JKT LNG demand growth to around 3% (year-on-year) to 2015, reaching 120 MMt in 2015. Growth is estimated at 2.3% per year over the period to 2020. By 2025, JKT imports could reach more than 140 MMt/y.

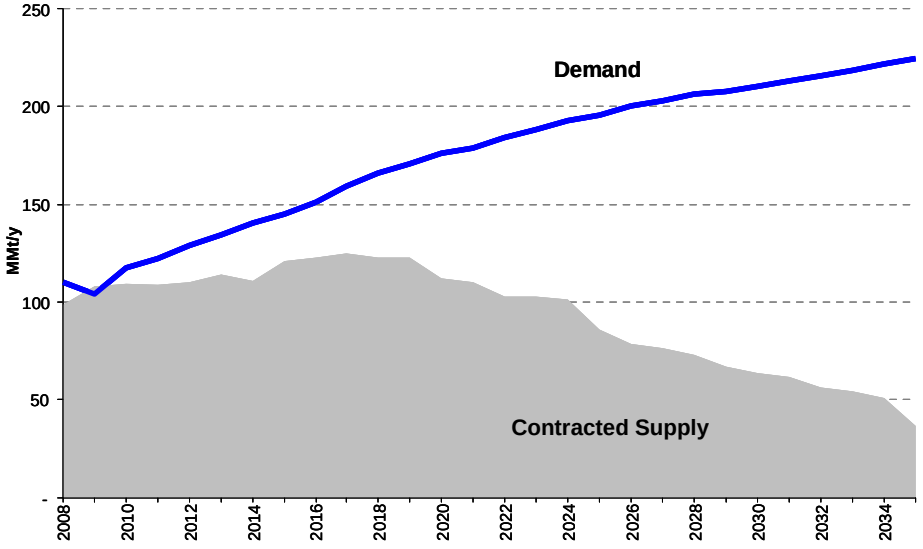
In contrast, new and emerging markets are projected to have stronger growth rates, starting from a lower base. In 2009, China and India accounted for 8% of global LNG consumption and 13% of Asian trade. Together, the emerging markets of India and China could represent over 33% of Asian trade by 2025. Niche markets are growing at a fast pace and by 2025 could account for 14 MMt/y – about as much as China and India together imported in 2009.

## *Key Asia Pacific Country Markets*

New LNG supplies from projects such as KM LNG will be needed to fill the supply demand gap in Asia. The primary target markets for Kitimat are JKT and China. We discuss each of these countries in turn below. There is an immediate need for additional long-term supply contracts to cover growing demand in these countries. The gap between long-term contracts and forecasted demand becomes critical starting around 2015 which is the period when KM LNG is projected to come on-stream. Comparing Poten's projected LNG demand for these four countries with existing contract volume (with some expiring by 2035), the supply demand gap could increase as much as 24 MMt/y by 2015, 64 MMt/y by 2020, 118 MMt/y by 2025 (assuming existing contracts are not renewed).

Major Asian exporting countries with contract expirations in this decade are Indonesia, Malaysia and Brunei. Most Indonesian contracts (Arun and Bontang) will likely not be renewed for South Korea and Taiwan (total of about 7 MMt/y), and only one quarter of Japanese contracts are expected to be renewed (equivalent to about 3 MMt/y). Brunei contracts with Japan and South Korea, and Malaysian contracts with JKT are also encountering renewals this decade. Uncertainties for potential renewals are increasing because of potential feedgas shortages in both countries and an increase in domestic gas demand in Malaysia.

**Figure 4[2]: Japan, South Korea, Taiwan, China Demand vs. Supply (Existing Contracts)**




[2] Figure 4 shows increasing gap between JKT & China demand and contracted LNG SPA supply, assuming expirations. Figure 1 on Page 2 on the other hand shows the entire Asia Pacific demand vs. exiting and under construction supply projects.

# *Japan*

*Overview*

Japan has very limited domestic natural gas production with no pipeline gas imports. Japan began importing LNG in 1969. The country is by far the world's largest LNG importer, accounting for 35% of global trade. While Japan imported 64.5 MMt of LNG in 2009, volumes fell 6.4% compared to the previous year due to lower demand as a result of the global financial crisis. Japan imported LNG mainly from Indonesia, Malaysia, Australia, Qatar, Brunei, Abu Dhabi, Oman and the USA under long term contracts and some shipments from Atlantic Basin exporters on a spot and short-term contract basis. Japan has twenty eight existing LNG import terminals with one currently under construction, and seven planned to commence construction by 2018. Existing send out capacity is around 25 bcf/d.

Seven electric utilities, Tokyo Electric Power Company (TEPCO), Chubu Electric Power, Kansai Electric Power, Tohoku Electric Power, Kyushu Electric Power, Chugoku Electric Power and Shikoku Electric Power accounted for approximately 65% of Japanese LNG imports in 2009. Other LNG buyers are the city gas distribution companies. Of the more than 240 city gas utilities, eight buy LNG. Tokyo Gas, Osaka Gas and Toho Gas are the largest city utilities.

**Figure 5: Japan LNG Import Terminals**

*Demand Projections & Drivers (Power & City Gas)*

With relatively modest GDP growth projections of between 1 to 2%, Japan's LNG demand is projected to expand gradually, driven by further development of Combined Cycle Gas Turbine ("CCGT") power generation, and switching from oil to natural gas use in the industrial sector. Overall LNG demand is projected to reach 72 MMt/y in 2015, 77 MMt/y in 2020, 82 MMt/y in 2025 and 85 MMt/y in 2030. This translates into a compound annual growth rate ("CAGR") of 1.4% between 2010 and 2020 and 1% between 2020 and 2030.

In 2009, the share of nuclear and LNG in Japan's total electricity generation mix were both 30%. However, LNG demand for power generation can suddenly increase as a result of a nuclear power facility shutdown (e.g., TEPCO's Kashiwazaki-Kariwa nuclear facility with total 8.2GW capacity was shut down in July 2007 due to an earthquake in northeast Japan). LNG-fired power generation is most often ramped up in the event of nuclear outages.

*Supply Demand Gap Issue*

With Japan's long-term LNG contract volumes standing at around 67 MMt/y at the end of 2009, the current situation of oversupply is projected to dissipate in 2011, as economic recovery takes hold and as Indonesian exports decline. Comparing Poten's projected LNG demand for Japan to existing contract volume (with some expiring by 2035), the supply demand gap could increase as much as 9 MMt/y by 2015, 27 MMt/y by 2020, 51 MMt/y by 2025 assuming existing contracts are not renewed. Only one quarter of Japanese contracts are expected to be renewed (equivalent to about 3 MMt/y), largely because of declining feedgas supplies in Indonesia and elsewhere. Japan is likely to be short of supply for each year until 2035 without new term-contracts. The shortage of supply is projected to reach 65 MMt/y by 2030 if existing contracts are not renewed and no additional ones are signed.

Japanese LNG buyers are aware of the potential of a supply tight market from around 2013 and are now seeking additional supplies to fill the gap. Driven by security of supply concerns, Japan will be active in securing reliable LNG supplies in the Asia Pacific and the Middle East over the coming years and occasionally sourcing supplies from the Atlantic Basin more on a spot to short-term contract basis. Having experienced volatile prices and fluctuating end use demand in the past several years – typified by the shift from a buyers' market in the early 2000s to a sellers' market in 2006 and then back to a buyers' market in 2010 – traditional Asian buyers are now seeking greater volume flexibility in new contracts beyond traditional take-or-pay obligations (e.g., through downward quantity tolerance (DQT) of up to 10% per year and equity LNG volumes) to accommodate fluctuations in base load demand.

*Summary / Key Drivers into the Future*

The underlying drivers for LNG demand in Japan will continue to be economic growth and the operation and development of existing and future nuclear power plants. With very limited domestic natural gas reserves or other energy resources, Japan's reliance on LNG will remain and a premium will always be placed on security of supply.

## *South Korea*

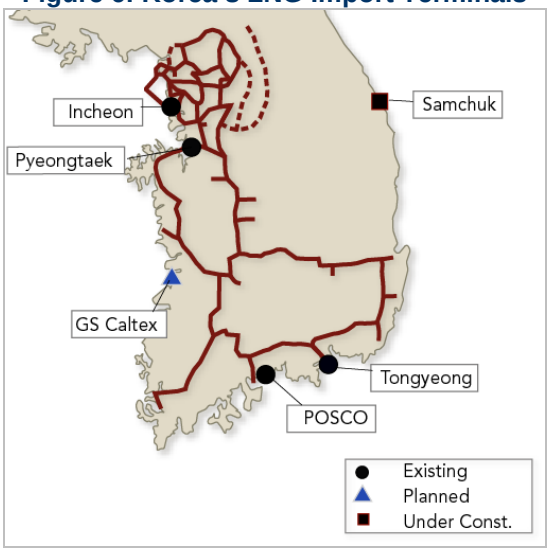
*Overview*

With limited domestic natural gas production, South Korea relies heavily on LNG imports for natural gas used for city gas production and power generation. Korea began importing LNG in 1986 and has maintained its position as the world's second largest LNG market. Due to the global financial crisis, in 2009 Korea's LNG imports fell by 12%. Korean imports represent over 13% of the global trade with LNG sourced from Qatar, Malaysia, Oman, Indonesia, Brunei, Australia, Abu Dhabi, Yemen, and Russia on a long term basis and from Atlantic Basin exporters on a spot and short-term contract basis.

State-owned Korea Gas (Kogas) is the dominant player in the country's natural gas sector, importing over 95% of LNG in Korea. Kogas is the world's largest corporate buyer of LNG and South Korea's sole natural gas wholesaler. Kogas operates three LNG import terminals at Pyeongtaek, Incheon, and Tongyeong, with a fourth under construction at Samchuk. Its customers consist of city gas users (63%) and power companies (37%). As direct imports of LNG for captive use were made possible by the revised "Oil Business Law" enacted in 1998, Korean steelmaker Posco and power generator K-Power started imports in 2005 and 2006, respectively, having secured supply contracts with Tangguh LNG (Indonesia). Posco constructed

the first and only private import terminal at Gwangyang in the south of the country and it shares capacity at the terminal with K-Power.

**Figure 6: Korea's LNG Import Terminals**




*Demand Projections & Drivers (Power & City Gas)*

With GDP growth projected to rebound from the global financial crisis to 4-5%, Korea's LNG demand is also projected to grow, driven by growth in CCGT power generation and in city gas use. Overall LNG demand is projected to reach 34 MMt/y in 2015, 41 MMt/y in 2020, 45 MMt/y in 2025 and 49 MMt/y in 2030. This translates into CAGR of 3.3% between 2010 and 2020 and then dipping to 1.7% between 2020 and 2030.

*Highly seasonal demand profile*

Korea's gas market is highly seasonal, with winter peaks driven by space heating requirements, especially during periods of particularly cold weather. Large seasonal swings have led to a high dependence on spot market purchases and medium term contracts to meet peak winter needs in the past. In order to manage this issue of seasonality, Kogas has conducted an aggressive terminal upgrade program to boost storage capacity at its three existing import terminals. As of 2009, three terminals have 46 storage tanks with total capacity of 2.79 MMt.

*Supply Demand Gap Issue*

With South Korea's total long-term contract volume at 27 MMt/y in 2009, Korea's position of oversupply is projected to fall away over 2010, because of the combination of relatively strong economic growth and insufficient long-term contract volumes. Although it will receive additional volumes from the new Gorgon, Wheatstone and Gladstone LNG projects in Australia cerca 2015, it still needs more firm long-term supply. The shortfall is quite serious – as much as 10 MMt/y by 2015, 16 MMt/y by 2020, 29 MMt/y by 2025 (assuming existing contracts will not be renewed). Similar to Japan, Korea is likely to be short of supply every year until 2035 without new term-contracts.

*Russian pipeline import possibility*

The Korean government is still considering the feasibility of Russian pipeline gas imports. Current plans include the equivalent of 3 MMt/y of Russian gas arriving in 2015, rising to 7.5 MMt/y in 2017. Even with this additional potential gas source, which is very uncertain due to geopolitical issues around its transit through North Korea, the supply demand gap mentioned above will not fundamentally change. Kogas is aware of the potential tight gas supply market as of 2013 and is now aggressively seeking additional LNG supply to fill the gap.

*Summary / Key Drivers into the Future*

The underlying drivers for LNG demand in South Korea will continue to be economic growth but two other factors stand out – nuclear power plant development and the possibility of Russian pipeline gas imports. As with Japan, and with limited domestic natural gas reserves and other energy resources, Korea's reliance on LNG will remain and a premium will always be placed on security of supply. Of the traditional Asia Pacific importers, Korea has the highest growth rate, and by far the strongest seasonal fluctuations due to high winter heating loads.

## *Taiwan*

*Overview*

Taiwan only has limited domestic natural gas production with no pipeline imports, and relies almost exclusively on LNG imports for power generation and city gas supplies. Taiwan started importing LNG in 1990, and was the seventh largest LNG market in 2009, consuming 8.8 MMt of LNG or around 5% of the global trade. Taiwan imported LNG in 2009 mainly from Indonesia, Malaysia, Qatar, Oman and Australia under long term contracts and some spot shipments and from Atlantic Basin exporters on a spot and short-term contract basis.

State-owned Chinese Petroleum Corporation (CPC) is the sole importer of LNG in Taiwan. The company controls all aspects of natural gas supply in the country, including E&P, imports, domestic pipeline transportation and gas wholesaling. CPC operates two existing LNG import terminals at Yung-An and Taichung which commenced operations in 1990 and 2009, respectively. The two terminals have a combined send out capacity of 1.7 bcf/d. CPC's customers consist of city gas companies and power companies with Taiwan Power Company (Taipower) being the dominant end user of CPC-sourced LNG.

**Figure 7: Taiwan's LNG import terminals**

*Demand Projections & Drivers (Power & City Gas)*

With 5% GDP growth projected in the medium term, Taiwan's LNG demand is projected to grow steadily. It is underpinned by stronger economic and trade linkages to mainland China. Growth in LNG consumption in Taiwan is primarily driven by growth in gas used by CCGT power generators. Overall LNG demand is projected to reach 12 MMt/y in 2015, 15 MMt/y in 2020, 17 MMt/y in 2025 and 18 MMt/y in 2030. This translates into a CAGR of 5% between 2010 and 2020, which falls to 1.4% between 2020 and 2035. Taiwan's relatively temperate winter limits gas use for space heating in winter. However, its warm summer weather promotes the use of power generation to support the country's air conditioning load. Power generation accounts for over 80% of LNG use in Taiwan.

*Nuclear development uncertainty*

Taiwan has three nuclear power plants in operation (six reactors in total), amounting to 4.9 GW of capacity. Another plant with two reactors is under construction, aiming at commercial operations in 2011 and 2012, after many years of delays and stalled construction. Other nuclear plants are planned by Taipower but developments are still uncertain, and Taiwan's reliance on LNG for power generation should continue.

*Supply Demand Gap Issue*

A shortfall in Taiwan's LNG supply portfolio started to emerge in 2004, even before the commencement of the suppliers' market in 2007. As a result, Taiwan has relied on spot and short-term cargoes as necessary to fill the gap. This imbalance is projected to continue into the future with insufficient long-term contract volumes to fill the projected shortfall. Taiwan's total existing long-term contracted volume was 6.8 MMt/y in 2009. Additional term volumes from Papua New Guinea starting in approximately 2015 will partially help address the imbalance, but much more LNG supplies are needed. Weighing Poten's current LNG demand projections against Taiwan's existing LNG contract volumes (with some expiring by 2035), the supply demand gap is serious – as much as 6.5 MMt/y by 2015 and10 MMt/y by 2020, and remaining at that level until 2025 (assuming existing contracts are be renewed). As with other traditional Asian markets, Taiwan is likely to be short of supply for each year until 2035 without new term contracts.

*Summary / Key Drivers into the Future*

The underlying drivers for LNG demand in Taiwan will continue to be economic growth and how its power generation portfolio develops. Just like Japan and South Korea, Taiwan has limited domestic natural gas reserves or other energy resources, and it will continue to rely on LNG to meet its essential energy security requirement.

## *China*

*Overview*

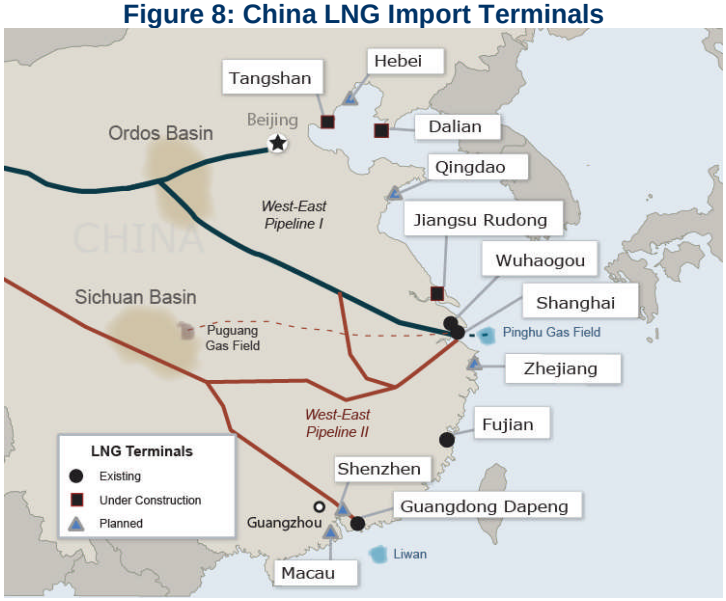
China is rapidly expanding its portfolio of LNG regasification terminals, LNG import contracts, as well as expanding pipeline imports. This reflects the government's concerns that energy shortages could stifle the country's economic development and potentially trigger domestic unrest.

China is far less reliant on gas imports than other Asian LNG importers. Unlike Japan, Korea or Taiwan, China has large domestic fossil fuel reserves – particularly of coal – which forms the backbone of its energy and electricity complex as well as having significant reserves of oil and gas.

The eastern coastal region of China, where existing LNG terminals are located in Guangdong, Fujian and Shanghai, represents the most rapidly growing region in the country where economic growth is underpinned by strong increases in energy consumption. The region lacks significant indigenous energy resources and therefore relies heavily on imports of energy from other parts of China and, increasingly, from overseas. As economic development and energy demand continues to move inland, China's overall energy requirements will expand further.

China has indeed experienced power shortages, leading, for example, to widespread blackouts in 2004.

**Figure 8: China LNG Import Terminals**



*Demand Projections & Drivers (power & city gas)*

Coal will remain the fuel of choice for electricity generation in China for the foreseeable future. While gas will be a niche electricity generation source it will become a key industrial fuel and have a growing role in city gas.

The overall natural gas demand for China is derived from forecasts of GDP growth, per capita energy use and fuel shares in power generation and other energy consuming sectors of the economy. Natural gas supply sources including domestic production (CBM included), pipeline imports and LNG have also been estimated.

In China, the industrial sector will be the dominant consumer of natural gas over the medium to longer term but its use will also grow in the city gas sector.

- Natural gas use in power generation is expected to increase but remains modest overall, with coal dominating at around 75%.

- Gas use in electricity generation will grow at an annual average rate of around 6% but still only account for around 27% of total gas consumption in 2035.

*Supply-Demand Gap Issue*

Gas supplies to meet this growing demand will be sourced from indigenous production, pipeline gas imports from central Asia, Russia, Myanmar and LNG. LNG is projected to help fill the shortfall between gas demand and domestic gas production in the coastal areas of China.

- The South East region of China – around Guangdong and Fujian – is far from China's domestic coal and gas reserves, making LNG an attractive fuel for both power generation and industrial uses, with power generation the major end market.

- In the area around Shanghai, including Jiangsu and Zhejiang, major industrial users dominate gas consumption. Imported LNG is likely to split roughly between industrial use and power generation depending on import terminal.

- In north China, in the Bohai Bay area, gas use is primarily underpinned by its use in industry. Given the abundance of coal fired power in this area, the majority of LNG imports are likely to be directed to industrial users such as steel works.

- Total LNG demand is projected to reach nearly 63 MMt/y (86 Bcm/y) by 2035. As a number of LNG contracts expire in the early 2030s, only 12 MMt/y is currently contracted in 2035.

- Pipeline imports could reach 55 Bcm/y by 2035 (40 MMt/y LNG equivalent), but this is largely dependent on the development domestic gas supplies, particularly unconventional gas.

*Summary / Key Drivers into the future*

The underlying drivers for natural gas demand will continue to be economic growth, population growth and the share of gas in China's overall energy mix. The key driver of LNG demand in China will be the degree to which overall gas demand in China can be satisfied by domestic production or pipeline imports.

China will continue to need large access to energy resources to feed its rapidly growing economy. Natural gas can provide China with an additional clean source of energy. We project LNG will play an important role in China's energy mix, as it complements natural gas domestic production and pipeline imports to sustain growing demand. Particularly, LNG will be an important contributor to coastal Chinese cities' energy needs in the power generation, industrial, commercial and residential sectors.

# Competing LNG Supply

## *1. Key findings*

Large amount of incremental LNG supply is needed to feed growing Asian demand. New export projects have to be developed in order to keep pace with the increase in consumption. We project the need for new export capacity will start in 2014, and will grow to reach 47 MMt in 2020, 85 MMt in 2025, and 130 MMt in 2035. These projects are beyond the more than 35 MMt/y of Asian-bound capacity currently under construction in Australia, Papua New Guinea and the Middle East.

- Buyers will need to make decisions now regarding long-term supply, to ensure sufficient supply is available from 2015 to 2020.
- New suppliers that can show they are likely to be operating during that period will have a significant opportunity to capture market share for the long-term.
- Large investment to support new infrastructure to liquefy, transport and regasify natural gas will be required, and this will call for significant capital investment. Investors in this new infrastructure will require a secure long-term commercial arrangement to underpin project returns and financing.

KM LNG is a natural choice to provide additional supply to Asian markets to cover the emerging supply gap.

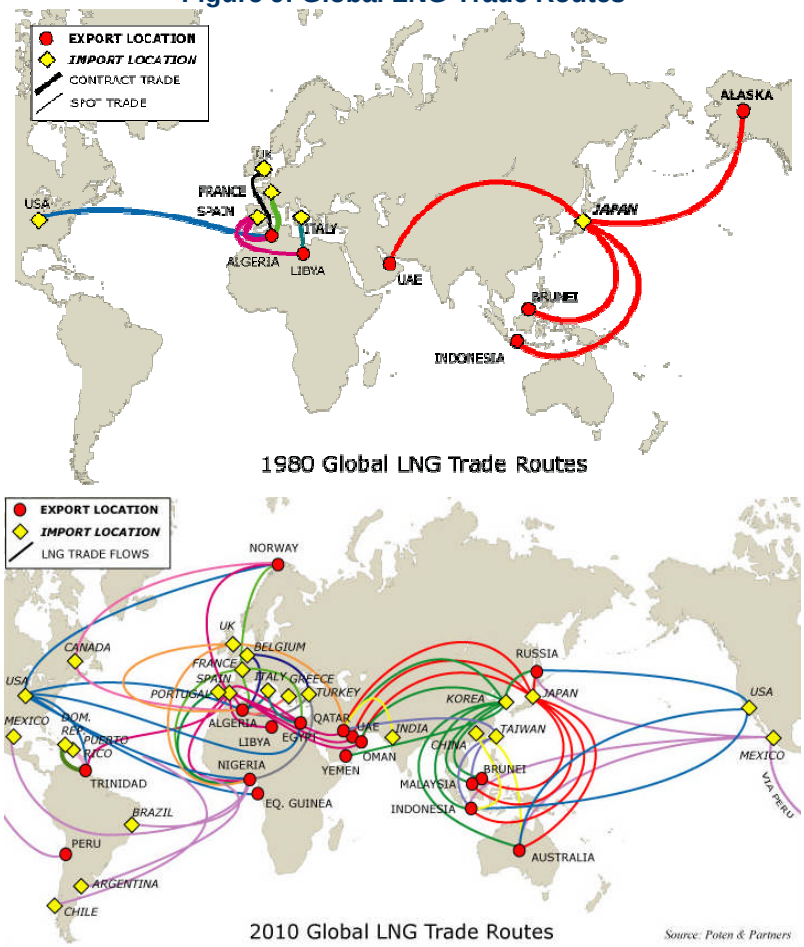
- Canada exhibits large natural gas resources, and is well located in proximity to the major LNG buyers Japan, Korea, Taiwan and China.
- Buyers may welcome the opportunity to diversify their supply sources, particularly in light of Canada's political stability and regulatory certainty.
- KM LNG has equity partners who are also large producers who have committed to supplying the LNG project from their corporate supply pools which include reserves and production throughout the Western Sedimentary Basin.

There are currently a significant number of competing LNG supply projects being planned in Australia, but only about 30% are likely to be completed on time due to economic, political and EPC cost and availability constraints. Less than half of the projects have the potential to start operations in the 2014 to 2018 period.

## 2. Introduction

KM LNG will be entering the LNG trade in the most dynamic and competitive environment the LNG industry has ever experienced. The figure below shows that the LNG trade has changed drastically during the last 30 years. In 1980 for example, there were just a few "fixed" regional trades to Japan, Europe and the US. However by 2010, there is a maze of trades, combining long-term, short-term and spot deals spanning broad geographic regions. This evolution will continue so that by 2015 there will be further increases in both volumes traded and the complexity of the market, with many buyers and suppliers competing for winning positions.

**Figure 9: Global LNG Trade Routes**




KM LNG's location in Western Canada allows it to target premium markets in Asia Pacific. Given this proximity there will be strong competition from other Pacific Basin and Middle East export projects. Similar to KM LNG, these projects are targeting buyers in Japan, South Korea, Taiwan, China and other key locations. Also like KM LNG, many of these projects are aiming at a start-up date around 2015. In this section we will assess KM LNG's supply potential relative to other supply projects.

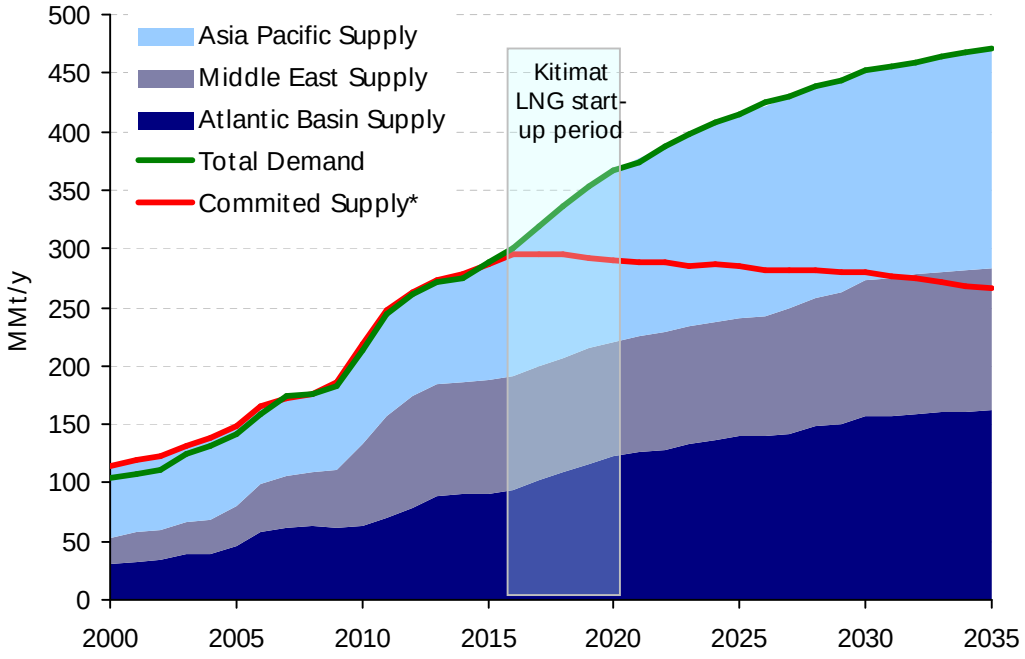
## *3. Global LNG supply*

Poten projects strong growth in global LNG supply, reaching more than 360 MMt/y by 2020 and more than 470 MMt/y by 2035. This is up from 182 MMt/y in 2009. The LNG market will balance (i.e. demand equal to supply) with the United States, the UK, and Northwest European markets taking remaining LNG after Asia and continental Europe satisfy their requirements. KM LNG's addition of up to 10 MMt/y post 2015 represents a small overall addition of less than 2% of the global supply.

By the end of this decade three countries could dominate the LNG export trade. Between them Qatar, Australia and Nigeria could be producing more than 190 MMt/y of LNG, representing more than 50% of the global export production. Australia particularly has huge potential to increase production further, to reach 110 MMt/y by 2030, gaining a global market share of close to 25%. In direct competition to KM LNG, various Australian projects are targeting the same premium priced Asian market.

Because of available gas resources, and premium prices and high demand for LNG in Asia, many supply projects are under development in the Pacific Basin. From 2015 to 2020, up to 65% of incremental supply is projected to come from Pacific Basin projects, with only 35% from the Atlantic Basin and the Middle East combined.

**Figure 10: Global Supply Increasingly Dominated by Pacific**




*Committed Supply: Existing export projects + Export projects under construction

KM LNG will be competing mainly with supply projects from the Pacific Basin. It is also important to consider the capability of the Middle East and Atlantic Basin suppliers to compete for premium Asian market with KM LNG.

The Middle East is projected to reach a plateau production level of around 95 MMt/y in 2012 after all six of Qatar's 7.8 MMt/y mega-trains are placed in service. Qatar has become the world's largest LNG producer and LNG from Qatar has a strong economic position due to plentiful liquids rich gas reserves and moderate development costs. This cost structure for LNG developments in Qatar was brought about by economies of scale, advantageous EPC contracts and cheap labor costs due to an international workforce of skilled and unskilled temporary laborers. Qatari projects also share marine facilities, LNG storage and other infrastructure.

Despite Qatar's strong position, we project limited competition for KM LNG from Middle East supply projects. Qatar has imposed a moratorium until at least 2013 on new gas projects from the 900 Tcf North Field and may not be building new LNG liquefaction plants this decade. However, Qatar did announce in late 2009 that it is contemplating debottlenecking the six mega-trains to add up to 12 MMt/y of production. If there is a threat to Kitimat from Qatari LNG it will be from existing production being diverted from the Atlantic Basin. Qatar has targeted supplying considerable volumes to the US and UK gas markets. However, because of lower prices in these markets Qatar has been diverting supplies to high priced long-term LNG buyers in Asia. While Qatar may continue to divert volumes they are only likely to do so at prices near oil parity (see pricing discussion below).

Of the other Middle Eastern producers, Iran is struggling to develop a liquefaction industry as sanctions limit access to Western technologies and companies. Prospects for Iranian LNG have further dimmed lately with the termination of relationships with several international oil companies (IOCs). Production out of Iran in the 2015 timeframe appears therefore to be highly unlikely. Oman, Yemen and Egypt are challenged by gas supply issues and further expansions are not currently planned.

Atlantic Basin projects have traditionally targeted markets in Europe and the Americas for long-term trade, and only ventured into the Asian LNG market through spot transactions. Based on this history, Atlantic Basin projects are not obvious direct competitors to KM LNG. However, attracted by higher Asian netbacks, Atlantic Basin projects may change tactics and begin to target key Asian buyers in competition with KM LNG. KM LNG may face potential competition from trains currently under construction in Algeria (a total of 9 MMt/y for two trains) and Angola (5.2 MMt/y one train) through Asian diversions.

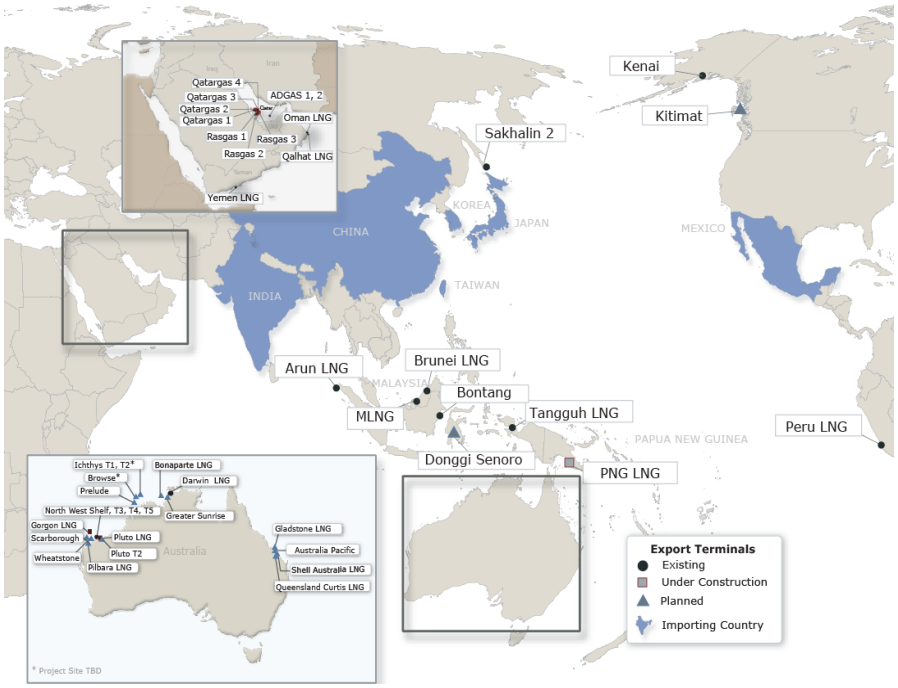
However none of the planned grassroots projects in the Atlantic basin seem to be serious competition by 2015. Remote locations and complex projects can make grass-roots African liquefaction ventures expensive. For example, the total installed cost for the Gassi Touil LNG plant in Algeria could top $5 billion, while Angola has similar cost challenges, falling just below $5 billion. Atlantic Basin expansion train projects are lower cost, but most are also struggling to develop by 2015 in the face of weak North American and European prices. Throughout North Africa, West Africa, the Caribbean, and Russia, liquefaction projects in the Atlantic often suffer

from technical complexity, high cost, limited feedgas availability, increasing domestic gas demand, and in some instances high political risk.

## *4. Pacific Basin LNG Supply*

Asian LNG markets, mainly Japan, Korea and Taiwan, have been traditionally served under long-term contracts with projects in the Pacific Basin or the Middle East. With the exception of the seasonal spot trade Atlantic Basin projects have not offered substantial long-term competition.

**Figure 11: Pacific Basin Supply Projects**




Historically, the largest Pacific Basin suppliers have been Malaysia and Indonesia, with a combined share peaking at 55% of the Asian LNG market around 2004. Indonesia has since lost ground due to lack of feedgas supply to its plants in Bontang and Arun, while Malaysian production is expected to stay fairly constant this decade. Neither of these historically important suppliers is considered a threat to Kitimat.

Australia's LNG production has been growing with its share of the Asian market reaching 15% in 2009. Australia's potential for further expansion is strong. Endowed with large natural gas reserves (3 Tcm), comparatively small domestic gas consumption (23 Bcm in 2009, R/P ratio of 73), stable political environment, and good long-term relationships with Asian buyers, Australia could surpass Qatar as the largest LNG supplier in the world by 2020 with a production increasing to around 75 MMt/y. Several Australian projects are targeting Final Investment Decisions (FID's) by 2012, placing them in direct competition with KM LNG.

The potential hurdles facing these projects that can be grouped under four headings: 1) Economics, 2) Political Risk 3) Marketing, and 4) EPC constraints.

**Economics**

The biggest hurdle to sanctioning an LNG project is the project's economic viability. There are many factors that can increase the cost of an LNG project and thereby reduce potential economic returns. Proposed LNG projects in Australia are particularly prone to this hurdle due to high costs.

*Australia - FPSO Projects (Prelude LNG, Bonaparte LNG, Greater Sunrise)*

No floating LNG projects have been built to date, and the ones that are being developed are at an early stage. Capital costs discussed by promoters appear competitive with onshore baseload LNG development opportunities, but as with any major innovation, there is a high potential for cost escalations. This cost uncertainty makes FLNG economics opaque. More accurate cost estimates will not be available until a full design is completed, and really not until the first LNG unit has been completed.

*Australia –CBM Projects Susceptible to Petroleum Resource Rent Tax*

Several LNG ventures based on coal bed methane feedgas are currently under development. The fiscal regime applied to Australia's CBM projects has changed for the worse and they will now be subject to Petroleum Resource Rent Tax (PRRT). These recent tax changes have caused significant uncertainty for CBM LNG project developers.

*Australia – All Projects – High costs driven by EPC resources and labor costs*

Scarcity of EPC resources including skilled labor has driven up the cost of Australian-based LNG projects so they are very expensive compared to projects in other regional locations. Modular construction techniques are being used to partially defray these higher Australian costs by moving fabrication work offshore to Asian fabrication and shipyards.

**Political and country risk**

Typically export projects in Asia Pacific have not been prone to as many political constraints as projects in Africa and the Middle East. However, some countries in Asia Pacific are experiencing difficulties with allocating gas between domestic use and LNG export. There are also cases of disagreements between countries that must jointly sanction an LNG export project. KM LNG has a considerable advantage over some of its competition as it is located in a region of political and regulatory stability, a characteristic that could make it attractive to potential Asian buyers seeking to enhance their security of supply. Other competing projects are being challenged and delayed by a difficult political environment of the host(s) country.

*Indonesia – Donggi Senoro*

The Donggi Senoro project has been plagued by delays due to disputes over whether the feedgas should be exported or allocated to growing domestic demand. In June 2009, Indonesia announced that the associated gas fields would be developed for domestic use. Since, the prognosis for the project has improved now the Energy & Mines ministry deciding to allocate 25-30% of the reserves from the Senoro and Matindok gas fields for domestic use, allocating the remainder to exports. In August 2009 Kansai Electric Power decided to no longer pursue buying

gas from Donggi due to uncertainty surrounding the Indonesian government's decision on the project, allowing a Heads of Agreement (HOA) for 1 MMt/y to expire. Instead Kyushu Electric Power Co. and Korea Gas (Kogas) plan to buy 0.3 MMt/y and 0.7 MMt/y respectively. Chubu Electric has also had a HoA for 1 MMt/y for some time.

*Australia – Greater Sunrise*

Australia's Woodside and the government of East Timor continue to be at odds over the development of the Greater Sunrise LNG project. In April 2010 Woodside announced that the Sunrise project would be developed as an FLNG project instead of piping the gas to Darwin in order to expand the Darwin LNG plant. However, East Timor is insisting on building an onshore plant in East Timor to process the gas. Under a treaty signed in 2007, the governments of both Australia and East Timor must approve the plans for monetization of the Sunrise field. Despite Woodside's announcement, a consensus must be formed before the project may proceed.

**Marketing Issues**

Every LNG project has its own set of challenges for marketing LNG.

*Australia – CBM Projects (Queensland Curtis, Gladstone LNG, Australia Pacific LNG, Shell Australia, Fisherman's Landing)*

The Australia CBM projects, all located on the east coast in Queensland, face a unique set of challenges. There has never been an LNG project based on coal bed methane as feedgas. One characteristic of CBM feedstock is that it is essentially pure methane, resulting in LNG that has lower energy content than other sources of LNG. Long established markets in Asia Pacific, especially Japan and Korea, favor LNG with a richer energy content. It is possible to spike the LNG with LPG to increase the energy content, but this increases cost.

*Asia Pacific and Middle Eastern Exporters - Diversification of Supply*

Traditional Asian LNG buyers such as Japan, Korea and Taiwan, already have long term SPAs with major LNG suppliers including Australia and Qatar. These buyer countries could favor purchasing LNG from a new supply country such as KM LNG in Canada to diversify their supply sources.

*Delay prone projects – Asian buyers will commit to projects that show most likelihood of success*

Many supply projects in Asia Pacific suffer from partners' misalignment on development timing and scope. Some projects have multiple partners, who in turn are involved in numerous competing projects in the region. This has complicated decision making and caused major delays in the past. KM LNG has strong and committed equity players in Apache Canada Ltd. and EOG Resources, which are clearly dedicated to monetizing their natural gas resources through LNG exports to premium Asian markets.

**Engineering, Procurement and Construction (EPC) Constraints**

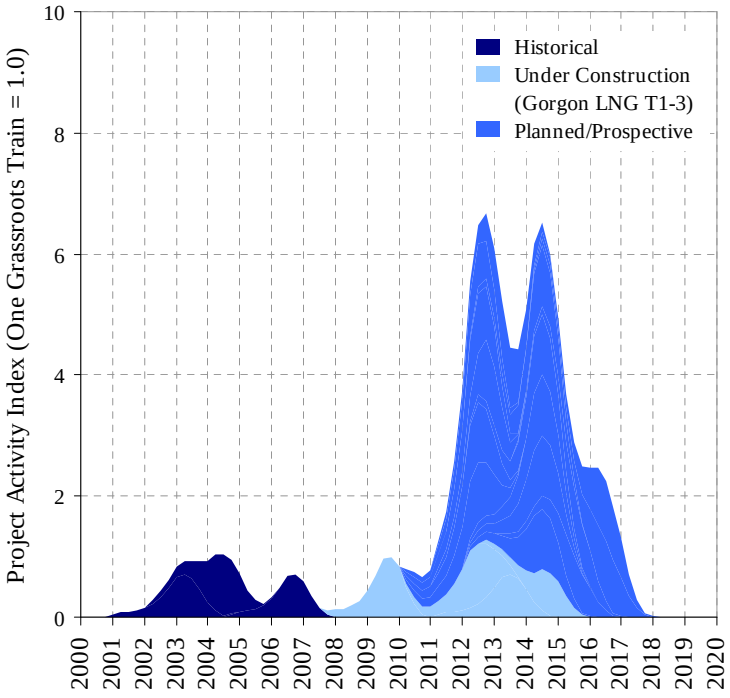
The workload of EPC contractors can limit the number of concurrent projects under construction, especially in the same region. Historical precedents limit the number of LNG trains at their peak construction load in a single year to eight worldwide. There are a limited number of qualified EPC contractors who are able to construct LNG plants. The major EPC contractors are Bechtel,

Chiyoda, Foster Wheeler, JGC, KBR, and Technip. As of this year CB&I successfully completed its first liquefaction project, Peru LNG. Due to the limit on the number of available contractors, who frequently form joint ventures between each other when constructing LNG plants, there is a limit to the number of liquefaction projects that can be constructed at the same time globally.

*Australia – Conventional and CBM Projects*

Australian LNG projects with targeted start-up dates between 2015 and 2020 include five conventional LNG projects, three floating LNG projects, and five CBM projects**.** This is in addition to three trains already under construction for the Gorgon LNG project, planned for start-up in 2014. EPC constraints are likely to limit the number of Australian projects that can potentially come online at the same time as KM LNG. Historically, there has never been more construction load than the equivalent of one LNG train, yet if all the planned projects went ahead; the construction load would reach almost seven trains in 2012 and 2014—close to the eight-train limit mentioned in the proceeding paragraph.

**Figure 12: EPC Constraints Australian LNG Projects**




CBM to LNG projects in Queensland face further EPC constraints as they compete for more limited resources in the state. Bechtel has been awarded the FEED for both the Queensland Curtis LNG project, and for Gladstone LNG. Bechtel is deemed as favorite EPC contractor for the CBM projects because it utilizes the Optimized Cascade liquefaction process. CBM-based projects must begin operation at much lower levels than traditional LNG ventures because it takes time to bring on the hundreds of wells required for full production, and these usually cannot be shut in once completed. The optimized cascade process is better suited for this environment than competing technologies since it spreads the refrigeration duty over multiple smaller turbine drivers and plate fin exchangers, each of which can be progressively brought online as needed.

# LNG Pricing

## 1. Key Findings

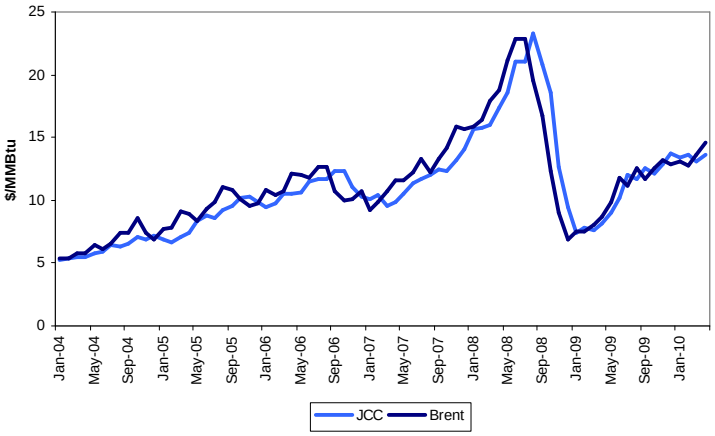
- LNG sold under long-term contracts in Asia Pacific is indexed to oil, and not likely to switch to gas-on-gas pricing in the foreseeable future.
- LNG sold under new long-term supply contracts to the Far East is currently priced around 90% of oil on an equivalent heating-value basis. Asian oil indexed prices are well above gas-on-gas prices in North America.
- The high prices for LNG reflect the geographic isolation and scarce indigenous energy resources of the traditional Asian LNG buying countries, along with the voracious appetite of China for energy resources. Far Eastern buyers have an overriding concern with security of supply and very low price sensitivity.
- Prices being negotiated for new long-term supply contracts reflect the continued high cost of LNG supply projects. Most of the new LNG supply ventures being developed for Asia Pacific markets would not get built if buyers were to insist on lower prices, since the projects would no longer be economical.
- Poten believes that prices for long-term LNG supply contracts probably will continue to be robust, both because oil prices will remain high and because contractual formulas will continue to price LNG at close to oil parity. Nonetheless, there is some potential for Asian LNG prices to drift lower over time.
- Through 2015 we estimate that ex-ship LNG prices for Far Eastern markets will be between $12 and $18 per million Btu.
- For the longer term we retain our top-end at $18/MMBtu (in constant 2010 dollars) but lower our bottom end to $9.50/MMBtu.

## 2. Long-term LNG pricing in major Far Eastern markets

Almost all LNG prices in the Asia-Pacific region are indexed to the average Japan Customs Cleared (JCC) price for oil imports. Though the mechanism for pricing against JCC is similar in the relevant markets, actual terms vary depending in part on market conditions in the period during which the contracts were negotiated. In contrast to North American markets, there is very limited gas-on-gas competition, and no trading hubs. The market instead consists essentially of negotiated long-term contracts with pricing formulas. A typical Asian pricing formula is as follows:

$$\textbf{LNG Price} = \alpha + \beta \cdot \textbf{JCC}$$

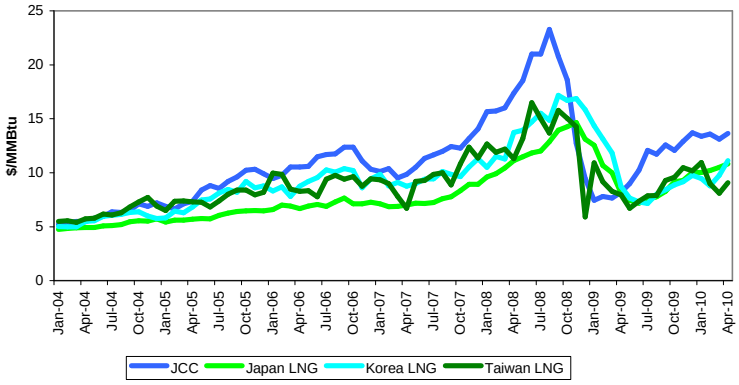
The JCC (also called Japanese Crude Cocktail) is the monthly average price for crude oil imports into Japan. It is compiled by the Japanese government. As the graph shows, the JCC closely tracks



Brent, though with a one- to two-month lag. The lag occurs because of the time that the Japanese government takes to compile the measure, which may involve more than 200 crudes from 30 countries.

Prices for LNG imports under term contracts for traditional LNG importers Japan, Korea and Taiwan track JCC, also with a lag. This lag occurs because the pricing formulas use historical averages of several months of JCC prices. Statistical modeling of term LNG prices for JKT on the historical average JCC prices is robust, although an additional variable is needed to capture the convergence of prices between the three countries starting in late 2007. Since that period, Japanese prices have tended to drift upward by around $0.05/month while Korean and Taiwanese prices have trended downward by around $0.02/month. The convergence in prices reflects the changing contract mix for the three countries. Japan has been adversely affected by lower deliveries under low-priced contracts with Indonesia, while Korea and Taiwan have benefitted from start-up of lower priced contracts that were negotiated early in the decade when the Far East was a buyers' market.

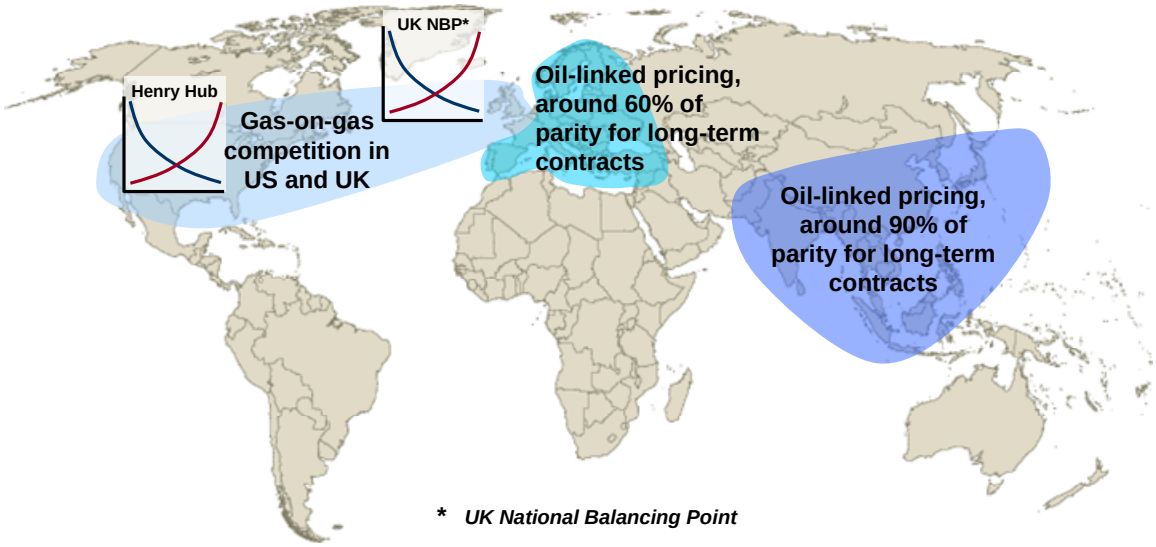
**Figure 14: Asian LNG Prices Track JCC**




Thus far, Chinese LNG import prices under long-term contracts have been much lower than JKT, reflecting the favorable moment it chose to secure its initial contracts, as discussed below. Through 2008 China's import price was essentially flat at $3.17/MMBtu, the ceiling price under its original contract with Australia's Northwest Shelf venture. Since 2009 its average import price movements under long-term contracts have also tracked JCC.

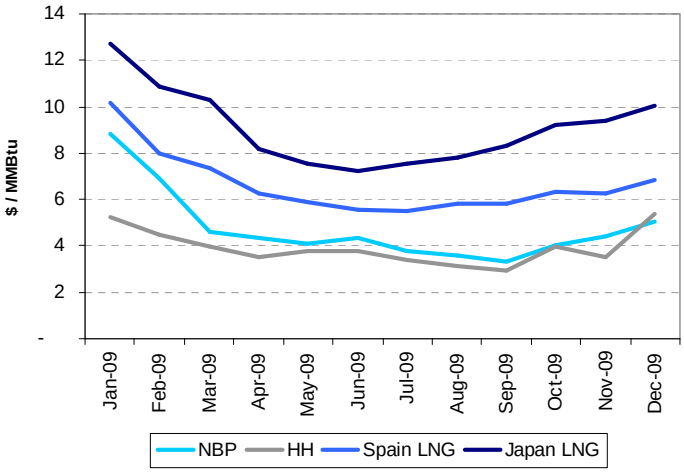
## 3. *Asia is the Premium LNG Market*

**Figure 15: Asia - The Premium Market**




There is a wide disparity between Asian LNG prices, gas prices in Continental Europe, and prices in gas-on-gas markets in Northwest Europe (primarily the UK's National Balancing Point) and North America (primarily Henry Hub). In 2009, Henry Hub, NBP, and Spanish LNG prices respectively averaged 43%, 53%, 73% of Japanese LNG prices. This large premium against Henry Hub and NBP is because LNG prices in Japan and in Far Eastern markets in general, are indexed to oil prices. Oil prices at present are relatively high compared to gas prices. The premium over Continental European prices is smaller because Continental prices are also indexed to oil and oil products. However, there is a stronger linkage to oil in formulas in Far Eastern markets which yields higher prices than in European markets. Indexation formulas yielding higher prices are commonly said to have higher slopes, since the contractual formulas are a constant plus a slope multiplied by the oil price. Higher slope means higher Beta.

**Figure 16: World Gas Prices in 2009**




Drivers of 2009 price differences are also drivers of scenarios for future Asian pricing. Over the next few decades, when the KM LNG export venture would be selling into Asia, Poten expects oil prices could increase sharply in the high scenario, due to robust demand growth and difficulties bringing on new supply. Our medium scenario shows more balanced future demand

and supply growth, with some upward pressure on prices. In our low scenario, prices remain in the mid $70s range due to strong conservation measures and supply growth coupled with weaker GDP growth in key consuming countries. Similarly, slopes for indexing formulas linking LNG prices to crude oil prices could stay the same, decrease with time, or decrease quickly. This suggests the following scenarios for future pricing:

| Scenario | Oil Prices | Slopes |
|---|---|---|
| High (LNG price of $18/MMBtu) | Much higher than now | Slight increase |
| Medium (LNG Price of $14/MMBtu) | Somewhat higher | Around current levels |
| Low (LNG Price of $9/MMBtu) | Around current levels | Gradual decrease |

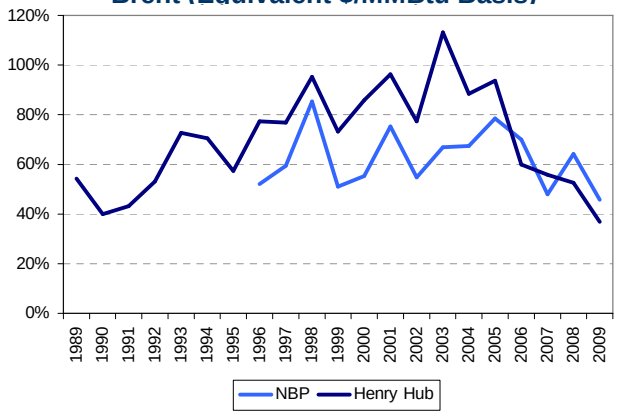
A potential fourth scenario would have Asian pricing move away from oil indexation entirely, adopting instead a price linked to Henry Hub or NBP, or eventually an Asian gas-on-gas pricing reference. We do not see any signs of this occurring for the foreseeable future.

We will discuss our High, Medium and Low scenarios, estimating both likelihood of occurrence and the likely trend price for Asian LNG should it occur. We will also provide the basis for our position that the movement of Asian LNG prices away from oil indexation is unrealistic for now. Before this discussion, though, we believe it is worthwhile to delve further into the reasons behind the drivers we have identified.

## *4. Abundant supply and low demand drive prices down in gas-on-gas markets*

The difference between oil prices and gas prices on an equivalent Btu basis in gas-on-gas markets has never been bigger. The unprecedentedly large discount for gas-on-gas prices reflects a "perfect storm" of three key developments, all of them bearish for gas prices: lower demand, booming unconventional gas production, and increasing LNG supply.

**Figure 17: Henry Hub and NBP Prices as a Percent of Brent (Equivalent $/MMBtu Basis)**




LNG supply also has been increasing as never before, mostly because of a series of mega trains coming on stream in Qatar. In 2009, the increased production from new LNG supply ventures was largely offset by lower production from existing ventures in Nigeria, Algeria, and elsewhere. Thus year-on-year LNG production actually declined by 2% for the first quarter of 2009. The offset has not lasted: for the first quarter of 2010 year-on-years supply was up 24%. Some 50 million tons of new LNG capacity will come on line by 2013, equivalent to 28% of 2009 traded volume.

Relatively low prices in gas-on-gas markets are a recent phenomenon caused by the "perfect storm" of bearish developments noted above. While we do see some recovery in US and UK prices from the current low levels, we believe that additional unconventional gas resources and effective cross-Atlantic price arbitrage is likely to keep prices in the range of $5.00 to $6.00 per million Btu (in constant 2010 dollars). This equates to oil prices in the low $30/bbl range on a Btu-equivalent basis. As a point of reference, the NYMEX forward price for Henry Hub natural gas quoted as of late August 2010 for December 2018 was $6.69/MMBtu, vs. $90/bbl for December 2018 Brent.

## *5. Higher oil-indexed prices in Asia than Continental Europe*

Our second driver for current price disparities and future scenarios is higher price slopes for oil-indexed LNG contracts in Far Eastern markets. These higher slopes are not because Asian buyers are unaware of events elsewhere in the world, nor are current negotiators likely to drive prices down to continental European prices, much less NBP or Henry Hub. Rather, the higher slopes reflect geographic isolation and scarce indigenous energy resources for traditional Asian buyer countries, along with the voracious appetite of China for energy resources. These conditions alone are enough to cause higher slopes in Far Eastern markets, but they are reinforced by an overriding concern with security of supply and very low price sensitivity, as reflected in elasticity of demand.

*Security of Supply*

Most of the major markets have few commercial oil or gas resources and little domestic production. JKT all import 97% or more of their oil requirements and 95% or more of their gas requirements.

Almost all gas imports for the JKT countries are LNG. There is some possibility of pipeline supplies from Eastern Russia to South Korea and Japan, but geography and geopolitics generally constrain this option. Japan and Taiwan, after all, are islands. South Korea is virtually an island since North Korea separates it from the Asian mainland. It is significant that Eastern Russia's initial gas exports have been LNG via the Sakhalin II project.

China's supply picture is the exception among Far Eastern LNG markets. In 2009 it imported 55% of its oil requirements and 7% of its gas requirements; it is far less reliant on imports, and thus might be presumed to have lower security-of-supply concerns. But China's rapid economic growth, coupled with its desire to diversify electric power generation away from (dirty) coal, means that its gas imports will continue to grow in both absolute and relative terms. It is rapidly expanding its portfolio of LNG regasification terminals, LNG import contracts, as well as expanding pipeline imports. Its gas imports will continue to grow strongly in absolute terms, and will likely gain market share vis-à-vis domestic gas production.

Security of supply is paramount in all these markets. For JKT, this is largely because of geographical remoteness from major suppliers and the lack of domestic supplies. For China it reflects the government's deep concern that energy could be a bottleneck in the country's economic development, and that energy shortages could trigger domestic unrest. China has indeed experienced power shortages, leading, for example, to widespread blackouts in 2004.

*Demand Insensitive to Price*

Because of the primacy of security of supply, gas demand in major Far East markets is very price inelastic. Some inelasticity can be explained by the fact that most LNG volumes are purchased under long-term contracts. The contract terms, however, are flexible enough to allow actual import volumes to reflect underlying price sensitivity, since they provide for quantity tolerances, make-up cargoes, and so on.

- Japan

For Japan, by far the world's largest LNG importer, statistical analysis for several different time periods over the past 15 years fails to uncover any significant relationship between monthly import LNG volumes under long-term contracts and real prices.

- Korea

Similarly, there is no statistical evidence of price elasticity of demand for Korea, and pricing parameters add nothing to statistical models of its volume history.

- Taiwan

Taiwan's LNG imports do show some price sensitivity but Taiwan's demand still clearly qualifies as price-inelastic.

- China

China, has only been importing LNG since late 2006 but has taken over as the Asian market leader, enabling new and costly liquefaction ventures to take final investment decision (FID). This is consistent not with a price-sensitive China, but rather with a China whose overriding concern is to secure the resources necessary to sustain its growth, regardless of price.

## *6. Recent Term Deals in the Far East*

While gas-on-gas prices have plunged and LNG deliveries into Northwest Europe and, to a lesser extent, the US have shot up, Far Eastern buyers have been contracting long-term LNG indexed to oil at terms that are close to oil parity on an equivalent Btu basis.

Price negotiations for LNG in Asia have been colored by medium term demand pressure and cost concerns.

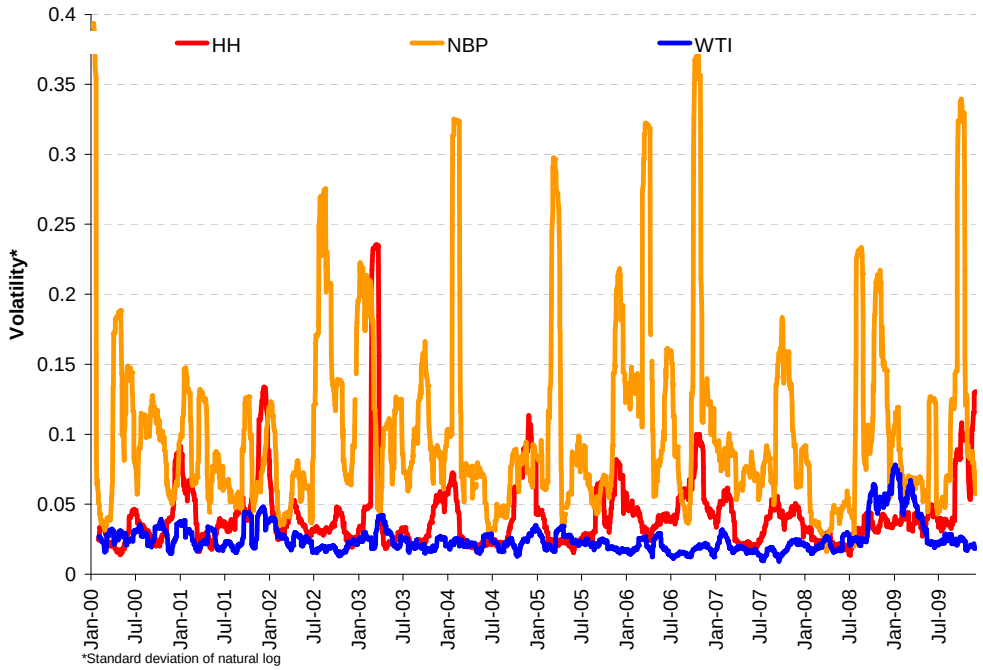
- Asian demand is growing, and buyers cannot satisfy their future gas needs unless additional LNG projects are sanctioned. Project sponsors, for their part, will not proceed to build the ventures unless the great majority of the LNG is sold under long-term contracts, to mitigate risk, secure project financing, and ensure the best pricing terms. Thus the buyers are under time pressure.

- Almost all of the new supply ventures are very costly projects in Australia and Papua New Guinea. Australian labor costs are very high. Nearly every project has feedgas issues, whether because of poor gas quality (Gorgon LNG), lean unconventional gas (Curtis LNG and Gladstone LNG), or locations far offshore or in the Papua New Guinea highlands. EPC costs for LNG ventures increased exponentially over much of the last decade, and have declined only modestly since the financial crash of September 2008. These LNG projects are likely to be uneconomical at lower pricing slopes.

## 7. Far East Contracts Will Not Shift to Henry Hub- or NBP-Based Pricing

The potential fourth scenario for Asia is when the entire pricing basis shifts to a gas-on-gas marker such as Henry Hub, NBP or perhaps an Asian pricing reference. This scenario has received some attention from LNG industry commentators, and Asia Pacific markets outside the core Far Eastern markets—i.e., Chile and Mexico—have indeed moved toward at least hybrid Henry Hub/Oil indexed pricing. At this point, though, it is pure speculation for JKT and China.

**Figure 18: Volatility of Henry Hub, NBP, and WTI**




## 8. Oil Price Scenarios

Poten's oil price forecast uses proprietary models. In our base case, prices climb by 20% from $80/bbl in 2010 to a peak of $95/bbl (in constant 2010 dollars) in 2022. After the initial climb, the average price is $90/bbl. In our high case, oil prices climb steadily to $110/bbl by the early years of the next decade and then average $110/bbl thereafter. In our low case, prices fluctuate around $75/bbl. Broadly, the reason why we discount a return to the lower price environment of past years, or any significant lowering from current levels, is the tremendous forecasted growth in oil demand in China and other developing countries. Until China's trend demand growth moderates—which appears unlikely to occur for many years—suppliers will be hard-pressed to keep up with demand. Conversely, we see no sign that the world's oil supply potential is peaking, and believe that under all circumstances, additional conservation and environmental measures will take some of the steam out of future demand growth.

The oil price window that emerges from our models is reasonable, but it does not incorporate extreme events such as wars or other turmoil in key supplier or consumer countries, or a sudden and massive shift to renewables worldwide, which might occur due to technology breakthroughs, high carbon taxes or regulatory intervention. Our oil price forecasts should be viewed as "p30", "p50" and "p70" cases, where p denotes the approximate probability of occurrence.

## *9. Scenarios for future LNG price slopes*

Poten's view is that prices slopes for long-term Asian LNG supply contracts are likely to continue to be robust. We believe that the low slopes for contracts signed in the early part of the last decade were an exception. Throughout its 40-year history, LNG has tended to be priced close to oil parity for long-term contracts in the Far East.

Our view is substantiated in part by current market conditions, regional fundamentals and the advantages of gas as a fossil fuel:

- Despite the surging supply and the effects of the economic crisis, new long-term contracts for LNG supplies to Asian with slopes around 14.85% (about 90% of oil parity on an ex-ship basis) continue to be signed. Downward pressure on slopes is being largely defused by increasing buyers' equity participation in the supply ventures.
- JKT will be willing to pay high prices due to their energy security concerns and market structure, while China will be willing to pay high prices to secure the energy needed to sustain high growth rates.
- LNG (natural gas) is a premium fuel, clean to use and low CO2 emissions.

Poten also believes that the required price for LNG plants serving the Asia Pacific region will probably need to continue to be high for the projects to achieve the minimum economic returns to proceed. This is due to feedgas quality issues such as high $CO_2$ and nitrogen content, high upstream development costs for remote deepwater fields, and low associated liquids as well as high Australia costs for construction labor. Lower slopes would likely cause at least the lower-return projects to be deferred, leading to supply shortfalls in the Asia Pacific region.

Our high scenario for slope is for the current benchmark to increase slightly, and to stay at this level indefinitely. This scenario is consistent with robust demand growth and a need to attract potentially costlier supply projects, such as floating LNG and Arctic gas. Under our most likely scenario, the current slope holds through the middle of the decade, and then edges down slightly. This scenario is consistent with more moderate demand growth and a slight downward tendency in supply project costs, which could occur due to an influx of qualified and experienced construction labor.

Even our low scenario has only a marginal decline in slope prior to the middle of the decade: we see no chance that sponsors of supply projects that could take FID in the near term will aggressively cut prices. Post-2015, though, our low scenario sees slopes pushed downward by additional Middle Eastern supplies from Qatar, Iran and/or Iraq, significantly lower development costs, and the encroachment of long-term Atlantic Basin supplies into Far Eastern markets.

As with the crude oil price forecasts, our potential future slopes should be seen as a reasonable range, but does not incorporate potential extreme events. For example, our high scenario does not contemplate the possibility that gas could come to command a premium over oil in Asia, although this could happen for environmental or other reasons. Similarly, our low case does not consider the possibility that Far East markets could develop plentiful, low cost sources of gas, as might

occur, for example, through massive exploitation of coal-bed methane in China or (more remotely) methane hydrates in Japan. The approximate probability of occurrence for these pricing scenarios is also p30/p50/p90, so that the combination of the respective high/high, medium/medium and low/low oil price and price slope scenarios yield approximate p10, p50 and p90 probability cases overall (e.g., 30% x 30% ~ 10%). The three scenarios are summarized in the following table.

**Figure 19: Pricing Scenarios for Far Eastern Markets**

| | | | Prices (2010$/MMBtu) | |
|---|---|---|---|---|
| Scenario | Probability | Oil price | Through 2015 | Post 2015 |
| High | 10% | $110 | $18.00 | $18.00 |
| Medium | 50% | $90 | $15.00 | $14.00 |
| Low | 90% | $75 | $12.00 | $9.00 |

## Conclusion

The Asia Pacific is KM LNG's primary market, for geographic and commercial reasons. LNG prices in Asia are linked to oil prices, under the most attractive natural gas price index formulas in the world. Demand for LNG in Asia is growing robustly, both in the traditional JKT countries and in the emerging markets, notably China. There is a wedge of unmet demand for long-term LNG supply after 2015 if no additional LNG supply projects are developed beyond those that are currently on stream or under construction. The gap between demand and long-term supply is forecasted to grow rapidly, already reaching 47 MMt/y by 2020. The size of this gap is far larger than KM LNG potential production of up to 10 MMt/y. Shipping distances are manageable, resulting in favorable shipping costs in particular to Japan, South Korea and the emerging market of Northern China.

The primary competitors to KM LNG are Australian projects. There are many such projects currently under development, but they have high costs and are increasingly complex. The scarcity of available skilled labor, feedgas quality issues, partner alignment and other concerns will cause many of the Australian projects to be delayed, and some could be cancelled entirely. This should create favorable conditions for Kitimat to market its volumes. Indeed, Asian LNG buyers may welcome the possibility of developing an additional source of future long-term LNG supply. Canada's well developed gas industry, regulatory environment, and prospects for growth make it an attractive place for such a diversification.