Pacific Basin LNG Market Analysis for Jordan Cove LNG Project

November 10, 2008

Submitted to:
Jordan Cove Energy Project, L.P.
125 Central Avenues, Suite 380
Coos Bay, Oregon 97420

Submitted by:
ICF International

This page intentionally blank.

Table of Contents

This page intentionally blank.

List of Tables

List of Figures

This page intentionally blank.

1 Executive Summary

The Jordan Cove Energy Project (JCEP) seeks to build a 1.2 billion cubic feet (Bcf) per day (peak send-out) LNG regasification facility at Coos Bay, Oregon with 6.4 Bcf of storage capacity. Tentative planned firm sources of LNG are from various projects in the Pacific Basin including those in Australia, Russia, Peru, and Papua New Guinea.

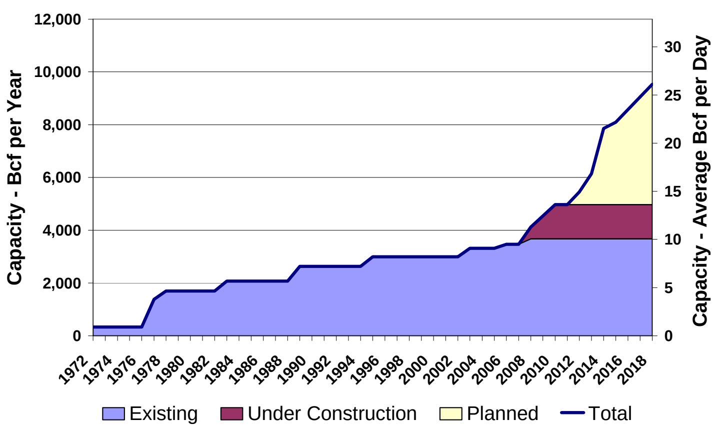
The Pacific Basin is forecast to be the location of a large percentage of world LNG liquefaction capacity growth by 2020 and beyond. However, a large portion of the growth in Pacific Basin LNG supplies is projected to serve markets in Japan, South Korea, China, and possibly India, due to their relative proximity to the exporting countries and their projected natural gas market growth. Unlike the U.S., where LNG prices are determined by a competitive natural gas market, Asian LNG contracts price LNG upon oil and other alternative fuel price formulas. Recently, Pacific Basin LNG import prices have been significantly higher relative to U.S. natural gas prices due to increases in oil prices.

This paper evaluates historic and forecast LNG productive capacity and markets in the Pacific Basin. The primary objective of the study is to answer the question:

> ***"Will it be possible for an LNG terminal located in the Pacific Northwest to attract supply given projected prices in other Pacific Basin Markets?"***

Liquefaction in the Pacific Basin is expected to increase significantly within the next decade. Projects currently under construction will add 1.3 trillion cubic feet (Tcf) per year of capacity, while additional planned facilities could add an additional 4.5 Tcf of capacity by 2020, excluding new projects in Qatar, Iran, Yemen, and other east of Suez Middle Eastern countries. Liquefaction capacity under construction is located in Australia, Indonesia, Peru, and Russia. Liquefaction facilities are sized to run at very high load factors. Incremental LNG supply available is approximated by the incremental capacity.

Figure 1 Pacific Basin Historic and Planned LNG Liquefaction Capacity



Pacific market imports of 4.8 Tcf accounted for 58 percent of the total world LNG imports in 2007. Four countries currently import LNG in the Pacific Rim: Japan, South Korea, Taiwan, and China. Among these, Japan accounts for the majority of the LNG imports in the region, with a

64 percent market share. By 2020, Pacific Basin imports could increase by 2.5 to 3.6 Tcf per year. China is expected to have the highest growth rate of any Asian market.

Table 1 Pacific Import Projections to 2010 and 2020 (Bcf per Year)

		2010		2020	
Country	2007	Low	High	Low	High
Japan	3,136	3,214	3,409	3,312	3,604
Korea	1,214	1,510	1,607	1,851	1,997
Taiwan	386	463	560	682	828
China	137	390	487	974	1,218
Others	-	-	-	584	828
Total	4,873	5,576	6,063	7,402	8,474
Delta 2007	0	703	1,190	2,529	3,601

Source: Institute of Energy Economics, Japan 2007

If all of the currently announced Pacific Basin projects are completed, LNG liquefaction capacity would increase by over 6 Tcf per year by 2020. Much greater than the 2.5 to 3.6 Tcf per year of incremental LNG imports currently projected for Pacific Basin imports. Despite the fact that not all the projects may be built, there will be excess LNG export capacity that could provide LNG imports to the U.S. west coast.

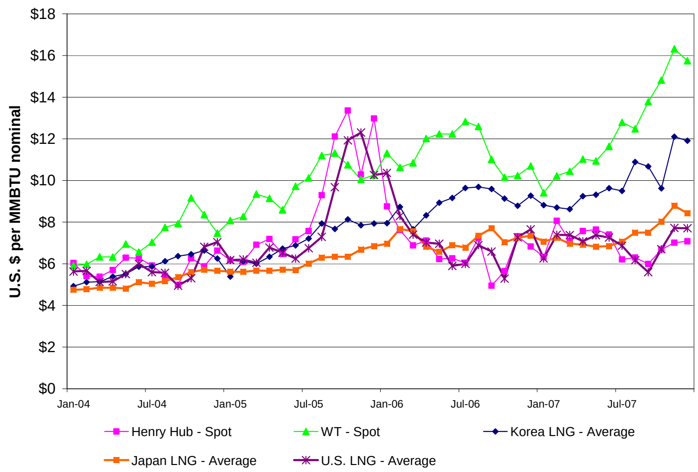
LNG markets are dominated by bilateral agreements between buyers and sellers. Because of the high investment costs for the LNG trade, suppliers historically have entered into long-term contracts with buyers to ensure recovery of those costs. The commercial arrangements are typically long-term, must-take contracts. Firmly committed supply to JCEP should benefit both the liquefaction project and JCEP's regasification terminal.

Spot (short term) trades have been growing. In 2007 spot cargoes accounted for 19% of world LNG imports. Increasing spot cargoes world-wide would increase the potential for non-firm deliveries to JCEP.

LNG imported into Asia Pacific countries and the U.S. is priced differently. Asian LNG prices are linked to the Japan Customs-cleared Crude or JCC, often nicknamed the "Japan Crude Cocktail." The link to oil prices is not 100%, however, since the JCC formula has a ceiling and floor price. Korean prices track more closely to oil due to contract terms with fewer price ceilings. U.S. prices are determined by supply and demand in the North American natural gas market which often leads to lower prices here than in the rest of Asia.

The cost of production, processing and shipping of Pacific Basin sourced LNG remains competitive with incremental North American natural gas supplies. As an example, the all inclusive delivered costs of Russian LNG to the U.S. west coast are estimated at about $6.70 per million British thermal units (MMBtu). This delivered cost is below recent and most future price projections for gas prices in the Pacific Northwest and California. (Other Asian exports may be less costly.) Variable costs of LNG, which represent the minimum price any seller would accept, are approximately $2.00 per MMBtu. Therefore even if gas prices in the U.S. are below Asian market prices, off-season LNG can still be delivered to the U.S. profitably.

Figure 2 Japan LNG, Korea LNG, Henry Hub Gas and WTI Oil Prices, 2004 – 2007



North America could provide a seasonal market for LNG because of the abundance of natural gas storage (4.6 Tcf working gas capacity total, 320 Bcf in California, Oregon and Washington). LNG shippers to Asian markets must schedule production and tanker shipments to meet swings in gas demand, which imposes costs on capital intensive operations since it leads to facilities use not being maximized. This provides an incentive for Asian LNG suppliers to seek alternate markets such as the U.S. LNG suppliers may guarantee delivery minimums year-round in order to secure summer delivery rights.

Another attractive aspect of the U.S. market is that if the LNG can be delivered, it can always be sold since the market is large and liquid. Markets clear on prices set by supply and demand and while for periods, gas prices may be lower than what they might be under a JCC formula, the LNG will be marketable. Other advantages of the U.S. market include the facts that gas prices here are sometimes above world LNG prices, U.S. purchasers are creditworthy, and that the value of the U.S. dollar is reasonably secure versus third world countries.

In conclusion, it is anticipated that there is sufficient LNG export potential in the Pacific Basin. The U.S. market is attractive as a seasonal market and a guaranteed outlet for LNG supplies. This surety of market provided by the U.S market would facilitate financing for new supply projects.

2 Introduction

The Jordan Cove Energy Project (JCEP or Project) is a proposed LNG import and regasification terminal for the Port of Coos Bay in Coos County, southwestern Oregon. The Project will receive ship-borne LNG, store it, regasify it, and deliver it into the new Pacific Connector Gas Pipeline (PCGP). The Project will accommodate medium-sized LNG tankers with carrying capacities of up to 160,000 cubic meters, or about 3.2 Bcf of gaseous equivalent.

The Project will be able to store up to 6.4 Bcf of natural gas in two storage tanks. It will have a base-load regasification capacity of 1 Bcf per day and a peak day send-out of 1.2 Bcf per day. The plant is planned to supply the growing demand for natural gas in the Pacific Northwest, a region lacking domestic natural gas production, and generally under-served by interstate gas transmission capacity, as well as other markets in the western U.S.

Tentative planned firm LNG sources for the Project are from Australia, Peru, Papua New Guinea and Russia. Other potential sources for the Project include other Pacific Basin exporters such as Alaska, Indonesia, Malaysia, and Brunei, as well as Middle East suppliers. The Pacific Basin is forecast to be the location of a large percentage of world LNG liquefaction capacity growth through 2020 and beyond.

However, a large portion of the growth in Pacific Basin LNG supplies is projected to serve markets in Japan, South Korea, China, and possibly India, due to their relative proximity to the exporting countries and their projected natural gas market growth. Unlike the U.S. where LNG prices are determined by a competitive natural gas market, many Asian LNG contracts price LNG upon oil and other alternative fuel price formulas. Recently, world oil prices (US$'s per MMBtu) have been much higher relative to U.S. natural gas prices. Therefore, Pacific Basin LNG import prices have historically been significantly higher relative to U.S. natural gas prices.

This paper evaluates historic and forecast LNG productive capacity and markets in the Pacific Basin. The primary objective of the study is to answer the question:

> ***"Will it be possible for an LNG terminal located in the Pacific Northwest to attract supply given projected prices in other Pacific Basin Markets?"***

Given that proposed LNG re-gasification terminals planned for the Pacific Northwest will not be in service until 2013 or later, it is from the post-2013 period that is of greatest importance for planning.

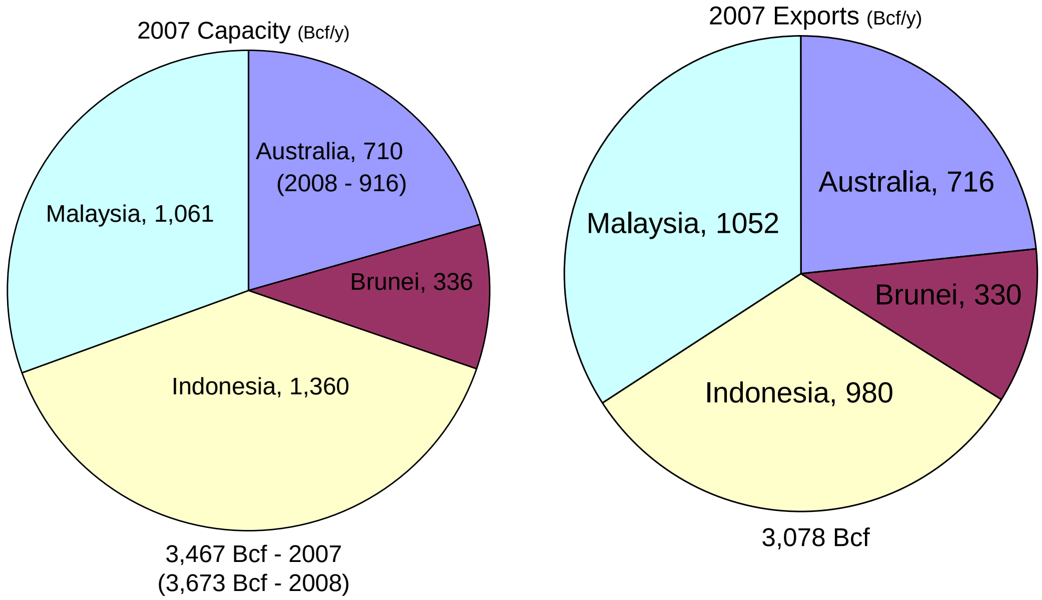
3 Current and Future Pacific Basin LNG Supply

A large portion of the world's LNG supply is produced in the Pacific Basin which is projected to see significant growth through 2020. This section describes historical and projected Pacific Basin LNG liquefaction capacity. Liquefaction plans for Australia, Russia, Peru, and Papa New Guinea, the potential firm suppliers for JCEP, are discussed in more detail.

Current and Anticipated Liquefaction Projects

Current operating LNG liquefaction capacity in the Pacific Basin is 3,673 Bcf per year, or about 40 percent of the world's total capacity. Four countries account for the vast bulk of LNG export terminals: Indonesia, Malaysia, Australia, and Brunei (Figure 3). (Alaska has a small LNG exporting terminal that has been in operation since the late 1960s.) In 2007, all the countries except Indonesia operated at a load factor in excess of 98 percent; with Indonesia operating at 73 percent. In 2008, Australia increased its LNG productive capacity by nearly 30 percent, or 206 Bcf per year by adding the NW Shelf #5 liquefaction train.

Figure 3 Pacific Basin LNG Exports and Liquefaction Capacity 2007 (Bcf/year)



The oldest liquefaction plants are in Brunei (1972) and Indonesia (1977 and 1978). The newest plats are in Australian with the NW Shelf and Darwin terminals built in 2006 and 2008, respectively.

Liquefaction capacity in the Pacific Basin is expected to increase significantly within the next decade. Currently under construction are projects that will add 1,294 Bcf per year of capacity, or an increase of 35 percent over current levels (Figure 5) by 2010. If all announced proposed projects are completed, Pacific LNG export capacity will more than double by 2020. Plants under construction are in Australia, Indonesia, Peru, Papua New Guinea, and Russia. Planned capacity is heavily dominated by Australia. The planned plants are scheduled to be operational during the period starting in 2012 and extending beyond 2015.

Figure 4 Pacific Basin Historic and Planned LNG Liquefaction Capacity

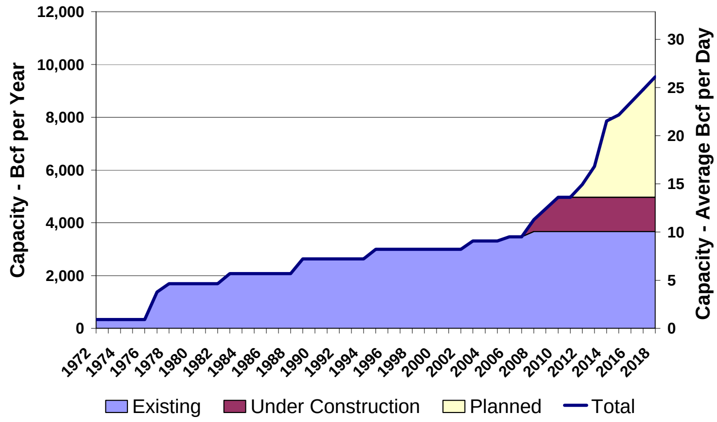


Figure 5 Forecast Pacific Basin Liquefaction Capacity – Existing and Under Construction

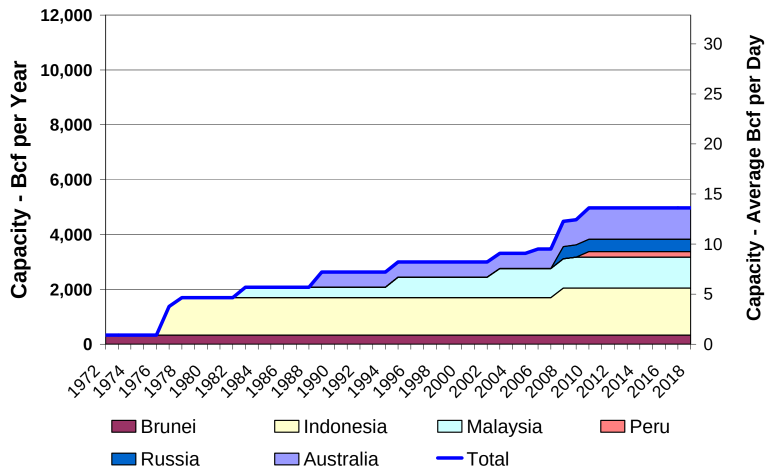
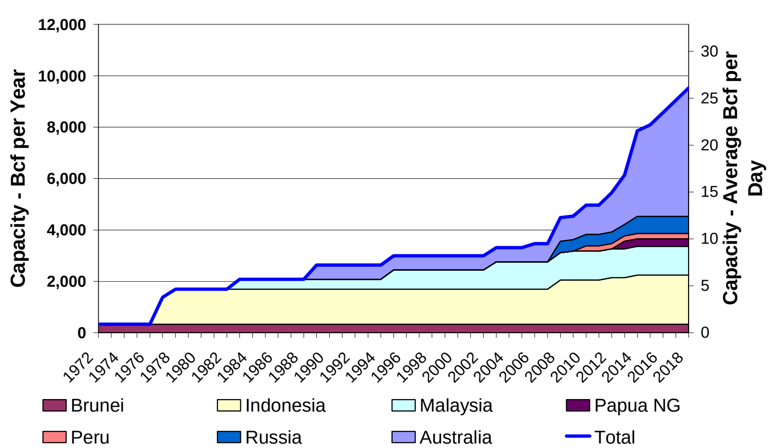


Figure 6 Pacific Basin Liquefaction Capacity – Operating, Under Construction, Planned



Source: LNG Journal and International Energy Agency, 2008, "Natural Gas Market Review."

Liquefaction Plans from Australia, Peru, Papua New Guinea, and Eastern Russia

JCEP plans to secure supplies from projects located in Australia, Peru, Papua New Guinea, and Russia's Sakhalin Island. All four countries have projects that are either under construction or in the advanced planning stages. At an estimated annual throughput of between 200 and 300 Bcf per year, JCEP could be a significant anchor tenant to any or all of these projects if they secured firm commitments. Large, firmly committed customers are often necessary to finance new liquefaction projects. Firmly committed supply to JCEP should benefit both the liquefaction project and JCEP's regasification terminal.

Australia

In 2007, Australia had enough capacity to produce 710 Bcf of LNG from five LNG trains at two liquefaction facilities: 1) Darwin LNG, which is owned by ConocoPhillips; and 2) Northwest Shelf LNG, which is owned by a consortium consisting of Woodside Energy, Shell, BHP Petroleum, BP, Chevron, and Japan Australia LNG. In 2008, Northwest Shelf LNG added a fifth train, which brought total Australian liquefaction capacity up to 916 Bcf per year, or 2.5 Bcf per day.

Currently, Australia has 12 LNG liquefaction projects that are either under construction or in the advanced planning stages. Of these, seven are projected to be in service by 2015. Assuming all of these projects are completed, Australia's liquefaction capacity could nearly quadruple to about 3,557 Bcf per year (9.7 Bcf per day). Projects planned for after 2015 account for an additional 1,439 Bcf per year of capacity, or about 3.9 Bcf per day. Some of the major players in the development of these facilities include Woodside Energy, ExxonMobil, Shell, Inpex, and BHP, and Chevron.

All of the supply sources for the projects to be completed by 2015 come from off the northwest coast of Australia. The fields that will supply these LNG facilities typically lie between 130 km and 450 km off of the coast. In total, these supply basins contain an estimated 84 Tcf of natural gas.

A significant portion of the LNG exported from these facilities is already destined for Asia Pacific countries, including China, India, Japan, South Korea, Singapore and Taiwan, as well as to Mexico. But, as Australian liquefaction capacity could outpace demand growth in the region, it is possible that some of this LNG could be available for the U.S.

Peru

The Peru LNG consortium consisting of Hunt Oil, SK of Korea, Repsol YPF of Spain, and Marubeni of Japan are constructing an LNG export terminal on Peru's southern coast 170 km south of Lima. The project, slated to be online in 2010, will be the first in Pacific South America, and at $3.8 billion it will be the largest private project in Peru's history. The plant's planned capacity is 215 Bcf per year, or just under 600 MMcf per day.

The gas source is the onshore Camisea field area which was first operational in 2004. The Camisea field area consists of several gas fields with reserves of 11 Tcf and 482 million barrels of NGL.[1,2] There is a gas pipeline in place to the Port of Pisco for local consumption. A new

[1] Hydrocarbons-technololgy.com website (see project listing under Camisea Gas Project, Peru)

400 km pipeline will be built as part of the LNG project to transport additional production to the coast for export as LNG.

Most of the gas (60%) is contracted to Mexico. The remaining 40 percent, or 86 Bcf per year, will be available for Asia and the U.S. In addition, Peru LNG is evaluating a second LNG train that would be operational by 2013.

Papua New Guinea

Exxon-Mobil and partners Oil Search, Santos, AGL Energy, and Nippon Oil, plan to construct an $11 billion, 300 Bcf per year LNG liquefaction facility in Papua New Guinea. The Papua government will join the project as an equity partner at a later date. Although this project is still listed as "proposed", design work was planned to begin in 2008 with a projected first shipment of LNG in 2013. However, recent trade press has indicated that the project may be delayed, with a possible 2014 export startup.[3] This is due to the global credit crunch, affecting borrowing costs and lending. In September 2008, the country's parliament passed multiple tax breaks to assist the developers by improving the construction economics.[4]

The terminal will be sourced by three gas field discoveries–Hides, Angore, and Juha–which are approximately 700 km from the planned facility in Port Moresby. Papua New Guinea's estimated gas reserves are 8 Tcf by the *Oil and Gas Journal* and 15 Tcf by *BP Statistical Review*. Papua New Guinea has no historic gas production.

In October, 2008, the Spanish Oil Company ENI announced an agreement with the country for hydrocarbon exploration, possibly leading to the eventual construction of additional LNG export capacity in the future.[5]

Russia (Pacific Coast)

Russia's Sakhalin LNG project is under construction and is slated for startup in early 2009. Interest owners include Gazprom, Shell, Mitsubishi, and Mitsui. As of early October, 2008, Phase 2 was over 95 percent complete. Phase 2 includes two new offshore platforms, an onshore gas processing facility, onshore pipelines, an oil export terminal, and the first LNG export plant in Russia. The capacity is slated to be 450 Bcf per year. An expansion is planned to be operational by 2013 with an additional 224 Bcf per year. Gas reserves associated with the development are said to be 17.5 Tcf. Volumes from the initial project have been contracted on a long-term basis to Asian countries and the Pacific coast. Due to its proximity, Japan is expected to secure a significant amount of gas from Sakhalin.

---

[2] EIA, 2008, "Peru Natural Gas," EIA Country Analysis Brief, www.eia.doe.gov/emeu/cabs/peru/naturalgas.html

[3] Lloyd's List, 2008, "LNG Supply to Remain Tight over Next Decade," October 7, 2008. www.lloydslist.com

[4] Sydney Morning Herald, 2008, "PNG Passes LNG Construction Tax Breaks," September 18, 2008.

[5] Dow Jones Newswire, 2008, "ENI, Papua New Guinea in Oil, Gas Exploration; EYE LNG," October 8, 2008.

4 Pacific Basin LNG Trade Patterns and Projected Pacific Basin Imports and Exports

The Pacific Basin is both a large source of LNG supply and a large consumer of LNG imports. This section describes historical trade patterns for both Pacific Basin LNG exporters and LNG importers. Projections of LNG imports for Asian Pacific countries are compared to under construction and planned LNG liquefaction capacity additions.

Recent Export and Import Patterns

In 2007, Asia Pacific[6] countries imported nearly 4.9 Tcf, or an average of 13.4 Bcf per day (Table 2). Pacific market imports accounted for 58 percent of the total world LNG imports in 2007. Four countries currently import LNG in the Pacific Rim: Japan, South Korea, Taiwan, and China. Japan accounts for the majority of the LNG imports in the region with a 64 percent market share. The relative spike in Japanese imports in 2007 is due in part to a nuclear power outage. China, having recently begun LNG imports in 2006, accounted for only 3 percent of the region's 2007 LNG imports but is a potential market for significant growth.

Table 2 Summary Pacific Basin Trade 2004 – 2007

Breakout of Source to Pacific Markets

		2004	2005	2006	2007	2007 Market Share
Total Pacific Sources						
To:	Japan	2,084	2,115	2,128	2,177	45%
	S. Korea	541	559	574	517	11%
	Taiwan	320	334	335	311	6%
	China	0	0	35	117	2%
	Total	2,945	3,008	3,072	3,122	64%
Total Non-Pacific Sources						
To:	Japan	633	580	762	959	20%
	S. Korea	514	516	631	697	14%
	Taiwan	2	5	25	75	2%
	China	0	0	0	20	0%
	Total	1,149	1,101	1,418	1,751	36%
Total from All Sources						
To:	Japan	2,717	2,695	2,890	3,136	64%
	S. Korea	1,055	1,075	1,205	1,214	25%
	Taiwan	322	339	360	386	8%
	China	0	0	35	137	3%
	Total	4,094	4,109	4,490	4,873	100%

Breakout of Pacific Source to Markets

		2004	2005	2006	2007	2007 Market Share
Total Pacific Markets						
From:	Indonesia	1,183	1,111	1,044	980	31%
	Malaysia	951	993	987	1,049	34%
	Australia	414	516	634	716	23%
	Brunei	335	323	346	330	11%
	Alaska	62	65	61	47	2%
	Total	2,945	3,008	3,072	3,122	100%
Total Non-Pacific Markets						
From:	Indonesia	0	0	0	0	0%
	Malaysia	26	14	4	3	0%
	Australia	16	8	3	0	0%
	Brunei	0	0	0	0	0%
	Alaska	0	0	0	0	0%
	Total	42	22	7	3	0%
Total to All Markets						
From:	Indonesia	1,183	1,111	1,044	980	31%
	Malaysia	977	1,007	991	1,052	34%
	Australia	430	524	637	716	23%
	Brunei	335	323	346	330	11%
	Alaska	62	65	61	47	2%
	Total	2,987	3,030	3,079	3,125	100%

Source: BP Statistical Review of World Energy.[7]

Currently Pacific Basin countries import just under two-thirds of their LNG from within the Pacific Basin. The remaining imports are sourced from non-Pacific countries mainly in the Middle East, and Africa.

[6] India, a country which imported 352 Bcf of LNG in 2007, is often grouped with the Asian countries listed. However, India imported all of its LNG supply from African and Middle East sources and was not included in this Pacific basin analysis.

[7] BP, 2008, "Statistical Review of World Energy." http://www.bp.com/productlanding.do?categoryId=6929&contentId=7044622

Nearly all Pacific Basin LNG liquefaction projects serve Pacific Basin markets. Less than 1 percent of LNG produced within the region is exported to non-Pacific markets. In general, regional LNG supply has been increasing. However, Indonesia and Alaska exports in 2007 were lower than the previous year. Indonesia has seen a shift from LNG exports in favor of the local fertilizer producers and the power sector.[8] Alaska's decline in 2007 exports was due mainly to planned terminal maintenance. In contrast, Australia LNG exports have been growing as more gas fields are developed and LNG export capacity is added. Australian LNG export levels of 717 Bcf in 2007 were over 70 percent greater than those attained in 2004.

Japan purchases LNG from several different countries with no single source above 20% of its total imports (Table 3). Both South Korea and Taiwan import heavily from Indonesia and Malaysia due, most likely, to their proximity. South Korea is the only country in the Pacific Basin that imports more LNG from outside Asia Pacific Basin than within. Nearly all of China's LNG imports are from Australia.

Table 3 Pacific Basin Trade by Country of Origin and Destination Country

Country of Origin to Market

		2004	2005	2006	2007	2007 Market Share
From Indonesia						
To:	Japan	748	671	657	638	65%
	S. Korea	258	265	237	181	18%
	Taiwan	177	175	150	161	16%
	China	0	0	0	0	0%
	Non Pacific Markets	0	0	0	0	0%
	Total	1,183	1,111	1,044	980	100%
From Malaysia						
To:	Japan	587	623	551	623	59%
	S. Korea	221	225	265	288	27%
	Taiwan	143	145	171	138	13%
	China	0	0	0	0	0%
	Non Pacific Markets	26	14	4	3	0%
	Total	977	1,007	991	1,052	100%
From Australia						
To:	Japan	395	461	554	567	79%
	S. Korea	19	41	31	20	3%
	Taiwan	0	14	14	12	2%
	China	0	0	35	117	16%
	Non Pacific Markets	16	8	3	0	0%
	Total	430	524	637	715	100%
From Brunei						
	Japan	292	295	305	302	92%
To:	S. Korea	43	28	41	28	8%
	Taiwan	0	0	0	0	0%
	China	0	0	0	0	0%
	Non Pacific Markets	0	0	0	0	0%
	Total	335	323	346	330	100%
From Alaska						
	Japan	62	65	61	47	100%
To:	S. Korea	0	0	0	0	0%
	Taiwan	0	0	0	0	0%
	China	0	0	0	0	0%
	Non Pacific Markets	0	0	0	0	0%
	Total	62	65	61	47	100%

Destination Market from Source

		2004	2005	2006	2007	2007 Market Share
To Japan						
From:	Indonesia	748	671	657	638	20%
	Malaysia	587	623	551	623	20%
	Australia	395	461	554	567	18%
	Brunei	292	295	305	302	10%
	Alaska	62	65	61	47	1%
	Non Pacific Sources	633	580	762	959	31%
	Total	2,717	2,695	2,890	3,136	100%
To South Korea						
From:	Indonesia	258	265	237	181	15%
	Malaysia	221	225	265	288	24%
	Australia	19	41	31	20	2%
	Brunei	43	28	41	28	2%
	Alaska	0	0	0	0	0%
	Non Pacific Sources	514	516	631	697	57%
	Total	1,055	1,075	1,205	1,214	100%
To Taiwan						
From:	Indonesia	177	175	150	161	42%
	Malaysia	143	145	171	138	36%
	Australia	0	14	14	12	3%
	Brunei	0	0	0	0	0%
	Alaska	0	0	0	0	0%
	Non Pacific Sources	2	5	25	75	19%
	Total	322	339	360	386	100%
To China						
From:	Indonesia	0	0	0	0	0%
	Malaysia	0	0	0	0	0%
	Australia	0	0	35	117	85%
	Brunei	0	0	0	0	0%
	Alaska	0	0	0	0	0%
	Non Pacific Sources	0	0	0	20	15%
	Total	0	0	35	137	100%

Projected Pacific Basin Imports and Exports

Within the next decade both Pacific Basin LNG imports and exports are projected to increase. The Institute of Energy Economics, Japan projects that by 2010 Pacific Basin LNG imports will increase by between 0.7 and 1.2 Tcf per year, or by 14 to 24 percent over 2007 levels (Table 4).

[8] APS Review Gas Market Trends, March, 2005

By 2020, Pacific Basin imports could increase by a total of 2.5 to 3.6 Tcf per year. China is expected to have the highest growth rate of any Asian market.

Table 4 Pacific Import Projections to 2010 and 2020 (Bcf per Year)

		2010		2020	
Country	2007	Low	High	Low	High
Japan	3,136	3,214	3,409	3,312	3,604
Korea	1,214	1,510	1,607	1,851	1,997
Taiwan	386	463	560	682	828
China	137	390	487	974	1,218
Others	-	-	-	584	828
Total	4,873	5,576	6,063	7,402	8,474
Delta 2007	0	703	1,190	2,529	3,601

Source: Institute of Energy Economics, Japan 2007

In a comparison based only on current LNG projects under construction, Pacific Basin LNG export capacity is due to increase by 1.5 Tcf per year by 2010. Since liquefaction capacity is often used at high load factors, especially for new projects, available LNG supply is expected to increase by a similar amount. Therefore, incremental LNG supply is projected to increase by more than even the high estimate of increased imports to existing Asian LNG markets.

Table 5 Summary - Projected Pacific Basin Liquefaction Capacity, 2007 - 2020

		2010	2020
	2007	Under Construction	plus Planned
All Sources	3,467	4,968	9,528
Delta 2007		1,501	6,061

Source: LNG Journal, International Energy Agency 2008, "Natural Gas market Review"

As indicated earlier, if all of the currently announced Pacific Basin projects, which are all in Australia, are also completed, LNG liquefaction capacity would increase by over 6 Tcf per year by 2020. Not all of these projects may be built. However, given the time horizon of over 10 years, by 2020 other Pacific Basin LNG liquefaction projects which are not currently publicly announced may be built. 6 Tcf per year is roughly double the 2.5 to 3.6 Tcf per year of incremental LNG imports currently projected for the Pacific Basin.

5 Asia Pacific and U.S. LNG Pricing

LNG imported into Asia Pacific countries and the U.S. are priced differently. This section describes commercial structures of the LNG trade and the general pricing terms of LNG imports into Japan, Korea, China, and the U.S.

Overview of LNG Commercial Structures

The creation and sale of LNG involves four distinct steps: exploration and production of the gas, liquefaction of the gas, transportation via ship, and terminaling and regasification of the LNG for delivery into the pipeline system. Historically, these functions have been carried out by different entities or a combination of entities.

Exploration and production activities are typically undertaken by the major state-run oil companies or joint ventures between them and international oil companies. Liquefaction is usually performed by joint ventures between integrated oil companies, trading companies, and national energy companies. LNG liquefaction trains are sized to serve specific export markets as defined by long-term sales agreements. Owners of the LNG at the liquefaction terminal most often sign long-term transportation charters with the ship owners.

The import terminal owner/operator takes the LNG from the tanker, cycles it through LNG storage tanks, and regasifies the LNG for injection into the pipeline system. The terminal owner/operators may simply offer tolling services for handling and regasifying the LNG. In some cases the LNG suppliers may own and operate the plant and sell gas at the terminal outlet to buyers as a one-price bundled supply. And in some cases the owner is an affiliate of a regulated gas or electric utility.

Jordan Cove is an example of an independent owner operated tolling facility that will secure commitments for a substantial portion of the terminal's capacity prior to initiation of construction. Although the terminal capacity has not yet been contracted, the typical capacity holders would be Pacific Rim LNG producers or LNG trading companies.

The entire LNG value chain is capital intensive. Liquefaction plants can cost $5.0 billion for a 1 Bcf per day output capability. Ships cost $200 million each. The number of ships required depends on the distance to market, as ships must constantly be in transit to maintain deliveries. A typical long distance arrangement for a 1 Bcf per day output might involve 8 ships. The receiving terminal is the least costly of the investments, at about $1.0 billion.

Exploration and production costs also can be significant and variable from region to region. However, the attractiveness of LNG is that it provides a way to market "stranded" gas supplies – supplies for which there is no local market. Often, the economic opportunity costs of these supplies are near zero. Table 3 builds up the total delivered cost of LNG for a hypothetical project in the Russian Far East. Costs represent both the full capital cost recovery and variable operating costs. The variable costs alone are approximately $2.00 per MMBtu of the $6.71 per MMBtu shown in the table. The significance of this is that at the margin, LNG costs can be significantly below prevailing market prices, and LNG has more freedom to flow towards markets that maximize value.

Table 6 LNG Value Chain for Russia/Far East 1 Bcf per day Project

Exploration & Production	$3.62/MMBtu
Liquefaction	$1.92/MMBtu
Shipping	$0.82/MMBtu
Storage & Regasification	$0.35/MMBtu
Total	**$6.71/MMBtu**

Source: ICF estimates

LNG markets are dominated by bilateral agreements between buyers and sellers. Because of the very high investment costs for the LNG trade, suppliers historically have entered into long-term contracts with buyers to ensure recovery of those costs and for a steady market outlet for the gas. Buyers in turn accept long-term contracts in order to secure a steady and reliable source of supply. Under these arrangements, buyers have had a limited ability to turn away ships while shippers have had a limited ability to redirect supply to other markets. Thus, the commercial arrangements typically end up being long-term, must-take contracts.

From 1995 to 2006, the world LNG market more than doubled from about 3.3 Tcf to 7.6 Tcf (Table 7).[9] As the level of LNG trading has increased, an active LNG spot market has emerged. In any market, there are, at the margin, mismatches between supply and demand for some periods of time. The spot market provides an outlet to deal with these mismatches. Given the relationship between variable cost and full costs of LNG, buyers and sellers in the spot market have significant opportunity to negotiate short-term trades. Short-term, or spot, trades now account for 19 percent of the total worldwide LNG market.

Table 7 Percentage of World LNG Trade that is Short-Term/Spot

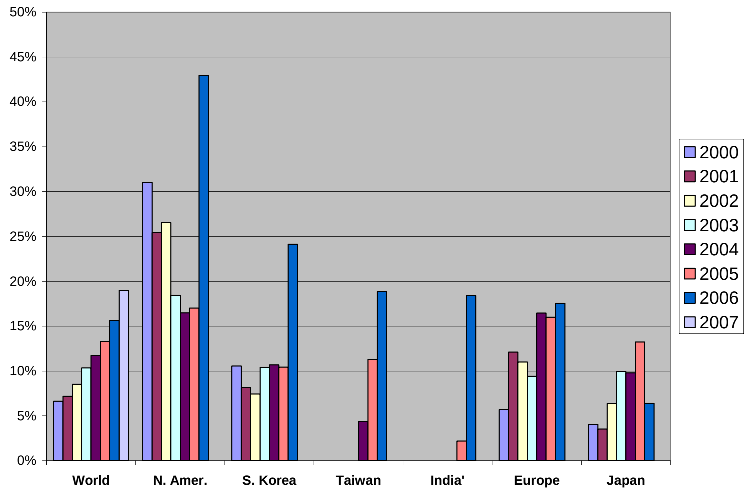
	Total LNG Trade Bcf	Total LNG Trade MMT	Spot/ Short Trades Bcf	Spot/ Short Trades MMT	% Spot/ Short Term
2000	4,933	106	348	7	7%
2001	5,194	111	398	8	7%
2002	5,370	115	487	10	9%
2003	5,912	127	651	13	10%
2004	6,375	136	796	16	12%
2005	6,843	146	970	20	13%
2006	7,627	163	1,268	26	16%
2007	7,995	171	1,616	33	19%

Sources: Morikawa, 2008, "Natural Gas and LNG Supply/Demand Trends in Asia and Atlantic Markets," Japanese Ministry of Energy and Trade.

North America has had a higher short-term percentage than the world average (Figure 7). While the Jordan Cove Project is expected to have a steady LNG supply arrangement from one or more of the proposed Pacific Basin LNG supply projects, it will also be likely to have contracted capacity with trading companies that will use the project as a market for spot cargoes, or other short-term cargoes in order to balance Pacific Basin supply and demand.

[9] Energy Information Administration, "International Liquefied Natural Gas (LNG) Imports and Exports by Country of Origin, 1993-2006. http://www.eia.doe.gov/emeu/international/gastrade.html

Figure 7 Short-term/Spot LNG Volumes as a Percentage of Total Volumes, 2000 – 2007



Sources: Morikawa, 2008 and Andrew Flower, LNG Associates

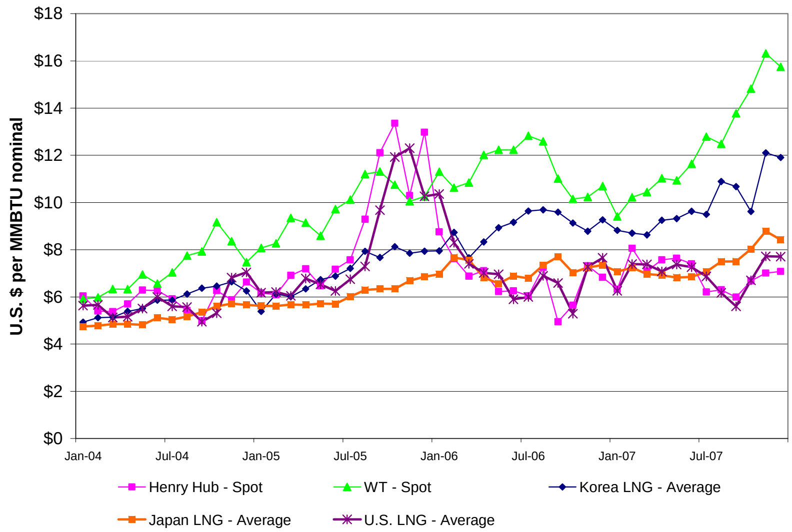
Pacific Basin and U.S. LNG Pricing

LNG pricing mechanisms and prices vary by region. Prices for most international LNG shipments are largely dependent upon oil prices. Asian LNG prices are linked to the Japan Customs-cleared Crude, or JCC, often nicknamed the "Japan Crude Cocktail". This is a market-basket of oil products that was developed in order to create a transparent price for LNG for sellers and buyers in the Japanese market. It represents, in part, the opportunity cost of LNG and was developed at a time when there was no independent verifiable market price. In the United States, gas prices are determined by market forces of supply and demand. LNG, in turn, is priced at the prevailing price of gas where the LNG is imported. Thus, in the U.S. market, LNG importers are price takers.

In the major Pacific Basin LNG markets of Japan and Korea, LNG contracts have traditionally been long-term with the prices linked to the JCC. The link to oil prices is not 100 percent since the JCC formula has a ceiling and floor price. Currently, the price of LNG averages lower than 90 percent of the JCC (Figure 8). Due to LNG's soft linkage to oil, recent higher oil prices have not translated into equivalent increases in Japanese LNG prices, however, they do still trend with oil prices. In the first half of 2008, LNG was more than $5 per MMBtu cheaper than crude in Japanese markets.[10] Korean LNG prices are more closely aligned with oil prices and hence Korea has seen a significant increase in LNG costs

[10] IEA, 2008, ibid, pg. 86

Figure 8 Japan LNG Import Prices vs. Henry Hub Gas and U.S. Oil Prices, 2004 – 2007



Unlike Japan and Korea, North America has significant amounts of domestic natural gas and a continent-wide pipeline network for delivering gas to markets. Gas prices in North America are set by the forces of supply and demand in the region and fluctuate substantially. LNG has no special standing in this market and as such, LNG importers receive only the market clearing price prevailing in the region of the import terminals for their gas.

It is not likely that Japan will change its oil-based pricing system.[11] As a result, future prices for long-term contracts will be linked to world oil prices, and the specific amount of linkage will depend upon the contract terms. The relatively stronger linkage to oil to LNG in Korea can be expected to continue, as Korea is a relative newcomer to LNG imports, and long-term contracts are still in place. For the spot market into Japan, prices will depend on opportunity cost factors including domestic market prices in the U.S. and U.K.

As China becomes a larger importer it is not exactly clear how prices will track with those of Japan and Korea. China is heavily coal dependent and may try to secure pricing tied to its coal markets. India has pursued this approach over the years and has only recently begun to accept LNG priced at world market levels, which is tied to oil prices.

In short, we expect LNG in the Pacific markets to continue to be tied to oil prices in some fashion. The question is to what extent, or under what conditions, can the United States attract LNG given U.S. pricing dynamics. We do not expect many, if any, U.S. buyers to accept prices tied to world oil markets or fixed price contracts tied to LNG costs

There are conditions, however, under which the North American markets could appear more attractive. China may not be willing to take LNG that is not tied to coal prices. In this case, less LNG may ultimately flow to China. (This assumes China does not enter the upstream markets to develop the gas supply, liquefaction facilities, and ships.) Japan is not a growing market, so incremental demand will have to come from China or India. India has access to Middle Eastern supply and also continental supply from Iran, as well as from its own offshore fields.

---

[11] Morikawa, 2008, ibid

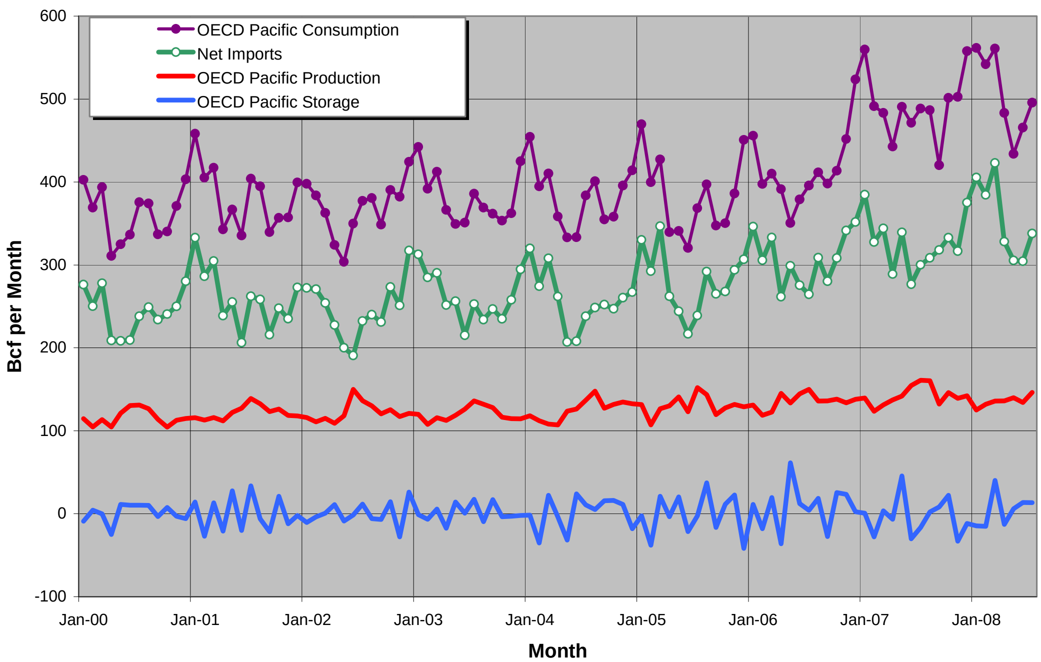
6 The Outlook for LNG Imports in the Pacific Northwest

Several trends argue for the importance of the North American market, particularly the United States, as a growing and attractive market for LNG. These trends include the increased significance of the United States due to its capacity for gas storage, the increased viability of LNG spot markets, and the fact that the United States provides a reliable source of market diversity to producers of LNG. These issues are addressed below.

The United States as a Market for Seasonal LNG Supplies

The United States may provide a seasonal market for LNG in the future because of the abundance of natural gas storage available compared to other Pacific Basin countries (Figure 7). OECD gas consumption is highly seasonal and growing. Imports, which are virtually all LNG, follow a seasonal consumption trend. Since there is no significant underground natural gas storage in the region, storage is limited to LNG tankage capacity at the receiving terminal. The patterns of injection and withdrawal are primarily driven by the daily schedules of tanker shipments and not seasonal consumption patterns.

Figure 7 Seasonal Gas Flows of OECD Pacific Countries



Source: International Energy Agency

In this environment, LNG shippers must schedule production and tanker shipments to meet swings in gas demand, which imposes significant costs on capital intensive operations since the facilities use is not maximized. This provides an incentive for LNG suppliers to Asian markets to seek alternate markets. The LNG suppliers may guarantee delivery minimums year-round in order to secure summer delivery rights.

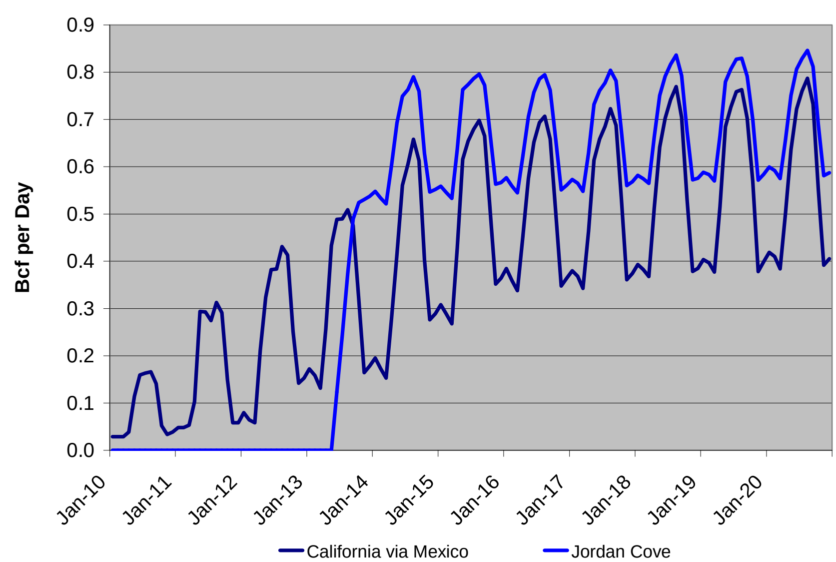
Depending on pricing, suppliers can be better off redirecting LNG to other markets when demand slackens in Japan and Korea. The United States can absorb the seasonal swings in supply despite having a consumption pattern similar to the Pacific markets. This is because of the abundance of storage. This pattern has characterized the Atlantic Basin LNG trade where gas prices in Europe have been much higher than U.S. prices on a seasonal basis, while the availability of storage in the United States allows producers to direct ships to the country in the off-peak season.

North America has over 4.6 Tcf of working gas storage capacity. California and the Pacific have over 320 Bcf. The West Coast of the U.S. has substantial capability to absorb LNG when Asian markets do not need it in the summer. Suppliers of LNG can ship LNG to the United States in the off-peak season (summer) where it can be stored or used for power generation, and then redirect LNG to other countries during the winter peaking season, when prices can be substantially higher than in the United States.

In addition, the size of the U.S. market is substantial compared to the rest of the OECD Pacific countries. Annual consumption in 2006 in California and the Pacific Northwest alone was about 2.7 Tcf, roughly the size of Japan and equivalent to almost 60 percent of the entire OECD Pacific gas market.

The expected patterns of deliveries of LNG into the West Coast are shown in **Figure 9**, based on ICF forecasts of the market through 2020. (The patterns stay the same after 2020.) Pacific Basin imports are expected to be countercyclical to North American consumption, which is similar to patterns of Atlantic Basin LNG imports.

Figure 9 Forecast U.S. West Coast Monthly LNG Imports 2010-2020



Market Diversification

Markets in Japan, South Korea, and other Asian countries are tied closely to power plant demand, hence the need for long-term secure contracts in order to ensure a steady fuel supply. U.S. gas markets are larger, more robust, and gas is more fungible, as it competes in many geographic markets with gas supplies from several U.S. and Canadian basins. Thus, an attractive aspect of the U.S. market to potential sellers of contract or spot LNG is that if the LNG can be delivered, it can always be sold into the very large market. Markets clear on prices set by supply and demand and while for periods, gas prices may be lower than what they might be under a JCC formula, the LNG will be marketable.

Other advantages of the U.S. market include: (1) gas prices here are sometimes above world LNG prices; (2) U.S. purchasers are creditworthy; and (3) the value of the U.S. dollar is reasonably secure versus third world countries.

7 Conclusions

- Pacific Basin LNG export capacity is due to increase by 1.5 Tcf per year by 2010, and by as high as 6.0 Tcf per year by 2020, based on terminals under construction and planned.

- If JCEP secured firm commitments from the potential firm suppliers – Australia, Peru, Papua New Guinea or Russia–JCEP would be significant anchor tenant. Firmly committed supply to JCEP should benefit financing of both the liquefaction project and JCEP's regasification terminal.

- The projected increase of LNG imports in the Pacific Basin by 2020 is between 2.5 Tcf and 3.6 Tcf per year. Therefore, incremental LNG supply is projected to increase by more than even the high estimate of increased imports to existing Asian LNG markets even if some of the planned capacity is not built.

- Spot trades have been growing. In 2007 spot cargoes accounted for 19% of world LNG imports. Increasing spot cargoes world wide would increase the potential for non-firm deliveries to JCEP.

- North America could provide a seasonal market for LNG because of the abundance of natural gas storage (4.6 Tcf working gas capacity total, 320 Bcf in California, Oregon and Washington).

- Due to the seasonal nature of current Asian markets, there is an incentive for Asian LNG suppliers to seek alternate markets such as the U.S. LNG suppliers may guarantee delivery minimums year-round in order to secure summer (off-peak) delivery rights.

- The U.S. market is large and liquid and LNG can always be sold at the prevailing market price.

8 Appendix – Supplemental Data Tables

Table 8 Pacific Basin LNG Plants: Operating, Under Construction, and Proposed

		Trains	Capacity MTPY	Capacity BCFY	Capacity BCFD	Start Year
Operating Plants						
Australia	NW Shelf LNG	4	11.9	556	1.524	1989
	NW Shelf #5	1	4.4	206	0.563	2008
	Darwin LNG	1?	3.3	154	0.422	2006
	Total	6	19.6	916	2.509	
Indonesia	Arun	2?	6.8	318	0.871	1978
	Bontang A-H	8	22.3	1,042	2.855	1977
	Total	10	29.1	1,360	4	
Malaysia	Satu	3	8.1	379	1.037	1983
	Dua	3	7.8	364	0.999	1995
	Tiga	2	6.8	318	0.871	2003
	Total	8	22.7	1,061	2.906	
Brunei	Brunei LNG	5	7.2	336	0.922	1972
Total Operating		29	78.6	3,673	10.063	
Under Contruction						
Australia	Pluto	1	4.8	224	0.615	2010
Indonesia	Tangguh	2	7.6	355	0.973	2009
Malaysia	Dua Expansion	1?	1.3	61	0.166	2009
Peru	Peru LNG	1	4.4	206	0.563	2010
Russia (Pacific)	Sakhalin	2	9.6	449	1.229	2008
Total Construction		7	27.7	1,294	3.546	
Proposed						
Australia	Browse	5?	15.0	701	1.920	2014
	Gladstone Fisherman Landing	1	1.3	61	0.166	2015+
	Gladstone Coalbed	3	8.5	397	1.088	2015+
	Greater Gorgon	3	15.0	701	1.920	2014
	Gorgon Expansion	2?	10.0	467	1.280	?
	Ichthys	2	8.4	393	1.075	2013
	Pluto 2	1	4.8	224	0.615	2012
	Prelude	1?	3.5	164	0.448	2012
	Scarborough	1?	6.0	280	0.768	2015+
	Sunrise	1?	5.0	234	0.640	2015+
	Wheatstone	1	5.0	234	0.640	2015
	Total	21	82.5	3,855	10.562	
Indonesia	Sulawesit (Donggi)	1?	2.0	93	0.256	2012
	Masela (= Abadi?)	1?	2.0	93	0.256	2014
	Total	2	4	187	0.512	
Papua New Guniea	PNG LNG	2	6.3	294	0.807	2013
Russia (Pacific)	Sakhalin Expansion	1?	4.8	224	0.615	2014
Total Proposed		26	97.6	4,561	12.495	
Total All Categories		62	203.9	9,528	26.105	

Table 9 Short-term/Spot Volumes vs. Long-term by Region

ICF; October, 2008
Sources: Morikawa, 2008 and Andrew Flower, LNG Associates

Short Term Trade Import Volumes - Million metric tons

	Total LNG Trade	North America	South Korea	Taiwan	India	Europe	Japan
2000	7	1.5	1.5	0.0	0.0	1.4	2.3
2001	8	1.3	1.3	0.0	0.0	3.0	2.1
2002	10	1.3	1.3	0.0	0.0	3.5	3.5
2003	13	2.0	2.0	0.0	0.0	2.8	6.0
2004	16	2.3	2.4	0.3	0.0	4.8	6.0
2005	20	2.3	2.4	0.8	0.1	5.8	8.1
2006	26	5.8	6.0	1.5	1.0	7.5	4.3
2007	33	not avail.	not avail.	not avail.	not avail.	not avail.	not avail.

Percent of Volumes That are Short Term

	Total	North America	South Korea	Taiwan	India	Europe	Japan
2000	7%	31%	11%	0%	n/a	6%	4%
2001	7%	25%	8%	0%	n/a	12%	4%
2002	9%	27%	7%	0%	n/a	11%	6%
2003	10%	18%	10%	0%	n/a	9%	10%
2004	12%	16%	11%	4%	0%	16%	10%
2005	13%	17%	10%	11%	2%	16%	13%
2006	16%	43%	24%	19%	18%	18%	6%
2007	19%	not avail.	not avail.	not avail.	not avail.	not avail.	not avail.

Calculated Long Term Trade Import Volumes

	World Short Term	North America	South Korea	Taiwan	India	Europe	Japan
2000	99	3	13	5	0	23	55
2001	103	4	15	5	0	22	57
2002	105	4	16	5	0	28	51
2003	113	9	17	6	0	27	54
2004	120	12	20	7	2	24	55
2005	127	11	21	6	4	30	53
2006	138	8	19	6	4	35	63
2007	139	not avail.	not avail.	not avail.	not avail.	not avail.	not avail.

Total Imports - MMT

	World Total	North America	South Korea	Taiwan	India	Europe	Japan
2000	105.6	4.8	14.2	4.7	0.0	24.6	56.9
2001	111.1	5.1	16.0	5.4	0.0	24.8	59.4
2002	114.9	4.9	17.5	5.3	0.0	31.8	54.9
2003	126.5	10.8	19.2	5.5	0.0	29.7	60.4
2004	136.4	14.0	22.5	6.9	2.0	29.1	61.3
2005	146.4	13.5	23.0	7.1	4.6	36.3	61.2
2006	163.2	13.5	24.9	8.0	5.4	42.8	67.1
2007	171.1	19.0	26.0	8.3	7.5	40.3	67.1