

# 3

## Liquefied Natural Gas: Alaska's Once and Future Export?

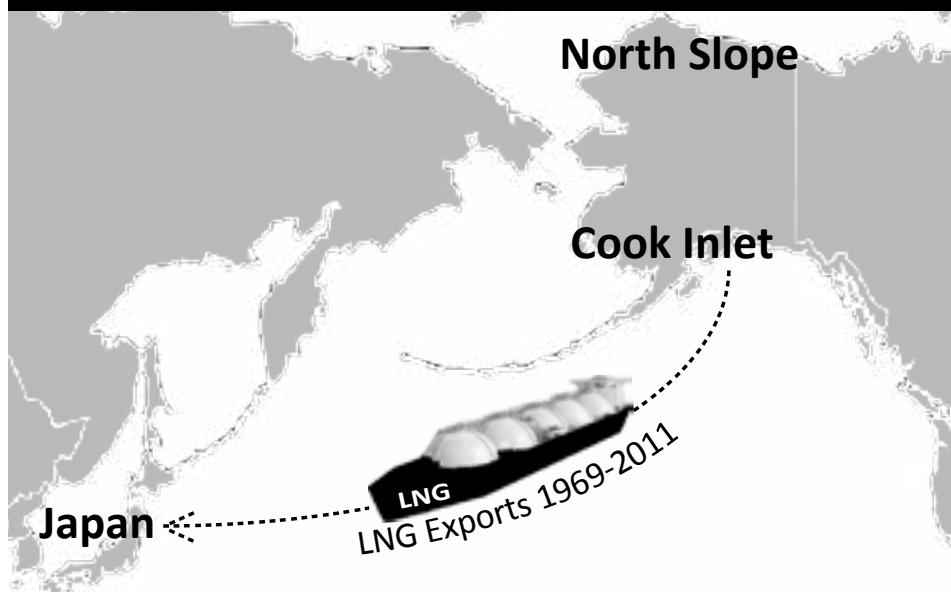
Natural gas is an abundant resource within Alaska.

Compared to oil production, natural gas production in Alaska is several orders of magnitude smaller, including the amount of tax revenue it generates for the State of Alaska. Nevertheless, natural gas production has played a significant role in Alaska's economy.

Alaska's natural gas production primarily comes from two regions: the Cook Inlet and the North Slope. The first major commercial gas discovery came in Cook Inlet in 1959, the year Alaska became a state. Natural gas was later found along with oil at Prudhoe Bay (central North Slope) in 1968.

The export of natural gas in a liquefied state to Japan was one of Alaska's first major world-class development projects. Cook Inlet natural gas has been produced for export to Japan and for in-state use for over a half-century. Overall, since 1959, Cook Inlet has produced over 7.75 trillion cubic feet of gas<sup>(1)</sup>; of this about 2.5 trillion cubic feet has been exported.<sup>(2)</sup>

**Figure 3-A: Geographic Overview**



Source: Background Image "Pacific Centric SVG World Map". [http://commons.wikimedia.org/wiki/File:Blank\\_Map\\_Pacific\\_World.svg](http://commons.wikimedia.org/wiki/File:Blank_Map_Pacific_World.svg). Accessed 13 November 2013.

Figure 3-B shows natural gas exports for Cook Inlet from 1989 to 2011. Regular exports to Japan ceased by 2011.

Locally, by the 1980s, natural gas became the primary fuel for generating electricity and for heating Alaska's largest city, Anchorage, and the "Railbelt" area tied into the electrical grid. Earlier, in the area of

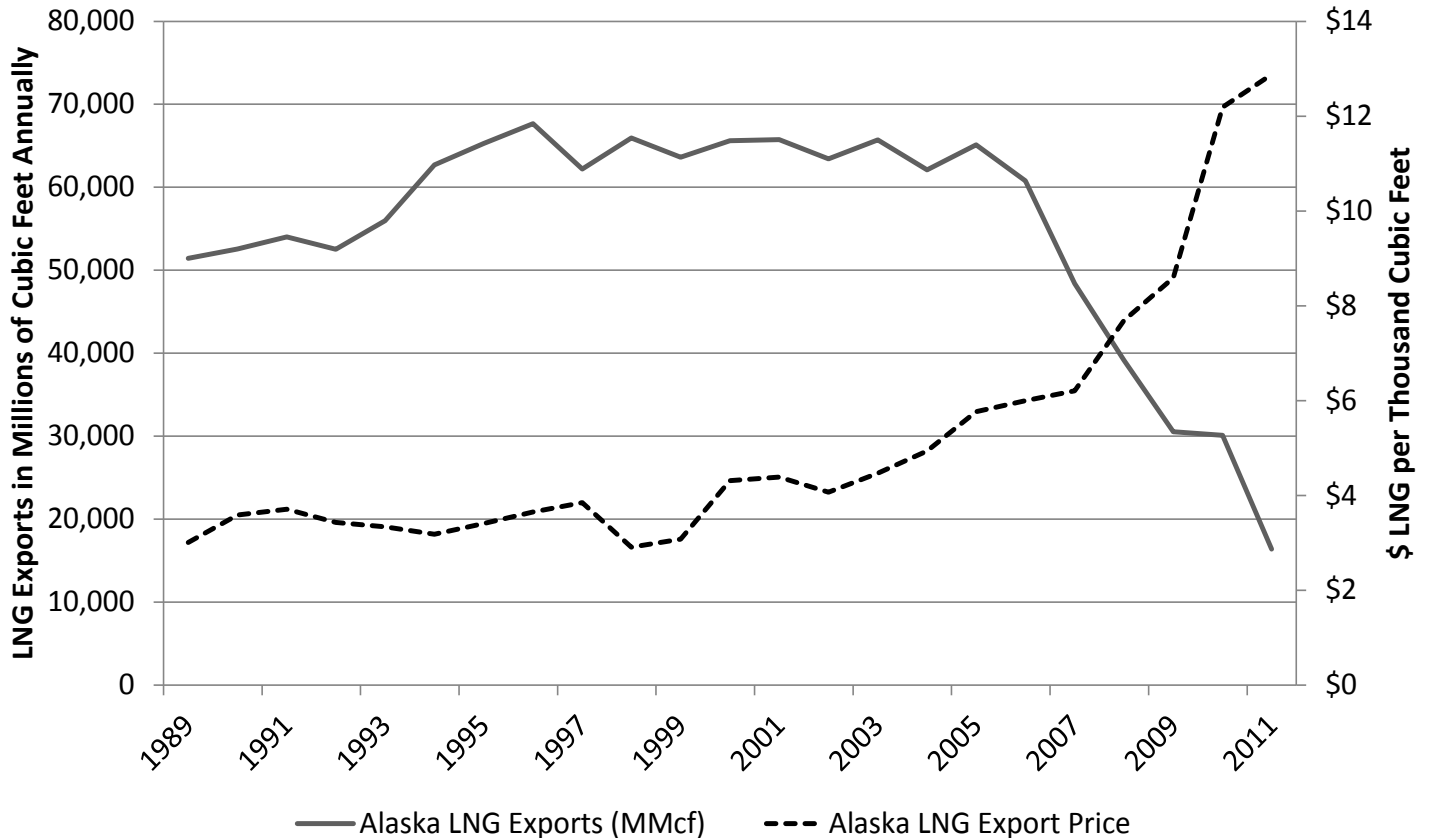
Barrow (western North Slope), the US Navy discovered natural gas as early as 1949. This field remains a source of energy for Barrow, one of the few settlements in the Arctic to be almost completely powered and heated by natural gas. The village of Nuiqsut (central North Slope) is also powered and heated by natural gas.

The export of LNG (liquefied

<sup>(1)</sup>This chapter will predominantly use the English conventions for measuring natural gas used in the United States, rather than the International System of Units (metric system).

<sup>(2)</sup>Oil and Gas Division of the Department of Natural Resources

**Figure 3-B: Alaska LNG Volumes and Price**



Source: US Energy Information Agency

natural gas) was one of the major drivers of Alaska’s economy and helped establish Alaska as an energy exporter. The export of LNG from Cook Inlet also set the stage in how the State would interact with the development of the North Slope – primarily in understanding that the act of exporting a resource outside of Alaska can be an engine of economic growth.

The possibility of a large-scale project that can export the immense North Slope natural gas resources to North American or global markets has been tantalizing and frustrating Alaskans for almost half a century. Economic

and commercial conditions for a North Slope natural gas project have not coalesced in the last forty years. Discussion about the potential of such exports is often a major issue within Alaska, and began about the same time major oil discoveries were made on the North Slope.

### Natural Gas Basics

Natural gas is a mixture of hydrocarbons, at least 70% methane (CH<sub>4</sub>) by volume, that, at ambient temperatures, is in gaseous form. The gas can be burned to release energy in the form of heat for electricity generation and steam generators, as well as residential, commercial,

and industrial heating and cooling. The heating value of natural gas within the US is defined as giving off between 950 and 1,100 British Thermal Units (BTU)<sup>(1)</sup> per standard cubic foot (scf), under standard atmospheric conditions. A barrel of oil, by comparison, gives off about as much energy as six thousand cubic feet (mcf) of natural gas. A common rule of thumb is to divide gas volumes in thousands of cubic feet by six to approximate the “barrel of oil equivalent” of gas production and consumption. The exact conversion factor varies.

<sup>(1)</sup> One BTU is the amount of energy needed to heat or cool one pound of water one degree.

Natural gas is more abundant and cleaner burning than other hydrocarbons, but is more difficult to transport and store. Like oil, natural gas can be transported over long distances in pipelines. However, unlike oil, which is liquid at ambient temperature, natural gas is difficult to ship by sea. Natural gas can be chilled to extremely cold temperatures (-259° F) to become a liquid. In its chilled state, natural gas is 600 times denser than the original gas at ambient temperatures. Liquefied natural gas can be easily transported on very large marine vessels to markets, where it is re-gasified and used as conventional natural gas. However, liquification is a costly process. One way to export natural gas from Alaska is to deliver gas by pipeline to a tidewater liquefaction plant, convert the gas to LNG and then ship it from a marine terminal to the destination market.

## **Alaska, an early global leader in LNG exports**

Alaska was one of the earliest pioneers in the global trade of LNG. A LNG plant on the Kenai Peninsula, in Nikiski, Alaska, operated between 1969 and 2011 and shipped gas to Japanese electrical utilities. This LNG plant was a globally significant project, since it was the world's second-ever intercontinental LNG project, after an export project between Algeria and Italy. In addition to monetizing a world-class natural gas source at tidewater, this project created the initial destination infrastructure that allowed Japan to become a major user of LNG from global sources. For the exporter, because of US maritime laws, primarily the Jones

Act, the LNG could be moved from Alaska overseas to Japan on low-cost, foreign-owned, foreign-built and foreign-operated tankers. This would not have been the case if LNG was delivered to the US, which would have required higher cost vessels and operating conditions related to the Jones Act.

For many years, Cook Inlet gas was considered relatively inexpensive, and was so plentiful relative to what was exported to Japan and what was locally used that the natural gas was also converted to a relatively low valued commodity, urea (ammonia) fertilizer, at a plant in Kenai, Alaska. The fertilizer was also exported. The plant was a major employer, with over 250 people employed, in the Kenai area from 1969 until 2007. Before it closed, it was the second largest producer of urea in the US.

Since the early 2000s, local demand for natural gas expanded with the growth of Alaska's population in the south-central area. At the same time, gas production declined, primarily because additional reserves were not developed within Cook Inlet. In 2011, according to the US Energy Information Administration, Alaska consumers used over 85 bcf of natural gas, which accounted for 63% of power generation in the State and 53% of heating fuel. See Figure 3-C for Alaska consumption trends from 2004-2011.

As natural gas prices in North America rose to all-time highs and the prices became higher relative to prices for LNG shipped to Asian markets, and since there was no regasification terminal to accept Alaska LNG on the US West Coast, the deposits in Cook Inlet were not

of great interest to the industry.

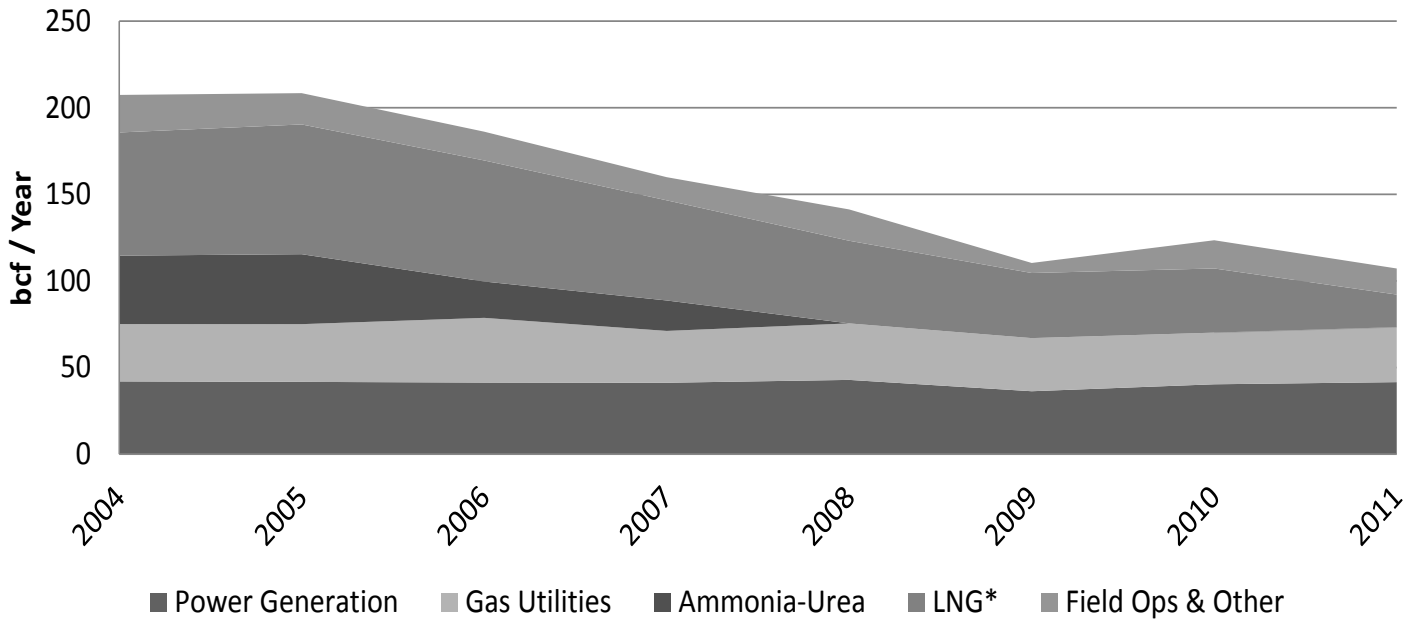
The fertilizer plant closed in 2007 and the LNG plant in 2011, as higher value use competed for diminishing gas production, and because proved gas reserves were not sufficient to meet anticipated Anchorage demand. For the same reason, lack of available gas forced the Nikiski LNG plant to close. Consistent LNG exports to Japan ceased in 2011. Figure 3-D show Cook Inlet contributions to production tax and royalty for 1991-2012.

## **Local Use of Natural Gas**

Resolving gas supply for Anchorage issue became an important issue for the Municipality of Anchorage and the State. In 2012, a gas storage facility was constructed, which allows extra gas produced in summer to be saved for use in the winter for peak demand, at times when demand outpaces production.

Several different proposals to resolve Anchorage's gas requirements included bringing natural gas from the North Slope by pipeline (small or large diameter); exploring and discovering additional reserves in the Cook Inlet and/or nearby; or, bringing in LNG into the Anchorage market. In the short-term, while production has declined and demand in south-central Alaska has increased, the overall rise in price as well as a fiscal policy that includes significant credits for exploration and development resulted in increased exploration. Increased exploration has, in turn, discovered new supply for natural gas, and the Anchorage market now has sufficient supply through 2018, according to the

**Figure 3-C: Cook Inlet Gas Consumption and Sum of Heating Degree Days Annually**



Source: Alaska Department of Natural Resources Oil and Gas Division

Department of Natural Resources.

A small amount of Cook Inlet gas is trucked to Fairbanks for heat and power. Currently, 1,100 households in the Fairbanks area use natural gas. For the most part, however, Fairbanks and most outlying areas of the State do not use natural gas for electricity generation, and face significantly higher utility costs than south-central Alaska. Fairbanks faces an energy crisis because of high prices for electricity and heating. The heating issue is exacerbated by the fact that many people are heating or supplementing their ordinary heating systems with firewood, which has created a significant problem with air quality in the area. Current limits of the facility in Big Lake (where the Cook Inlet gas is loaded on trucks) have created demand for a new supply source from the North Slope. Access to increased supply of gas for Fairbanks could reduce

the costs of both space heating and electrical generation for the Interior. Without a pipeline to supply the gas to Fairbanks, trucking gas from the North Slope has been proposed as a fast, flexible and efficient way to serve the Interior and resolve the gas supply issue for Fairbanks in the short-term. The trucking project has been discussed for several years, and may materialize in the near-term.

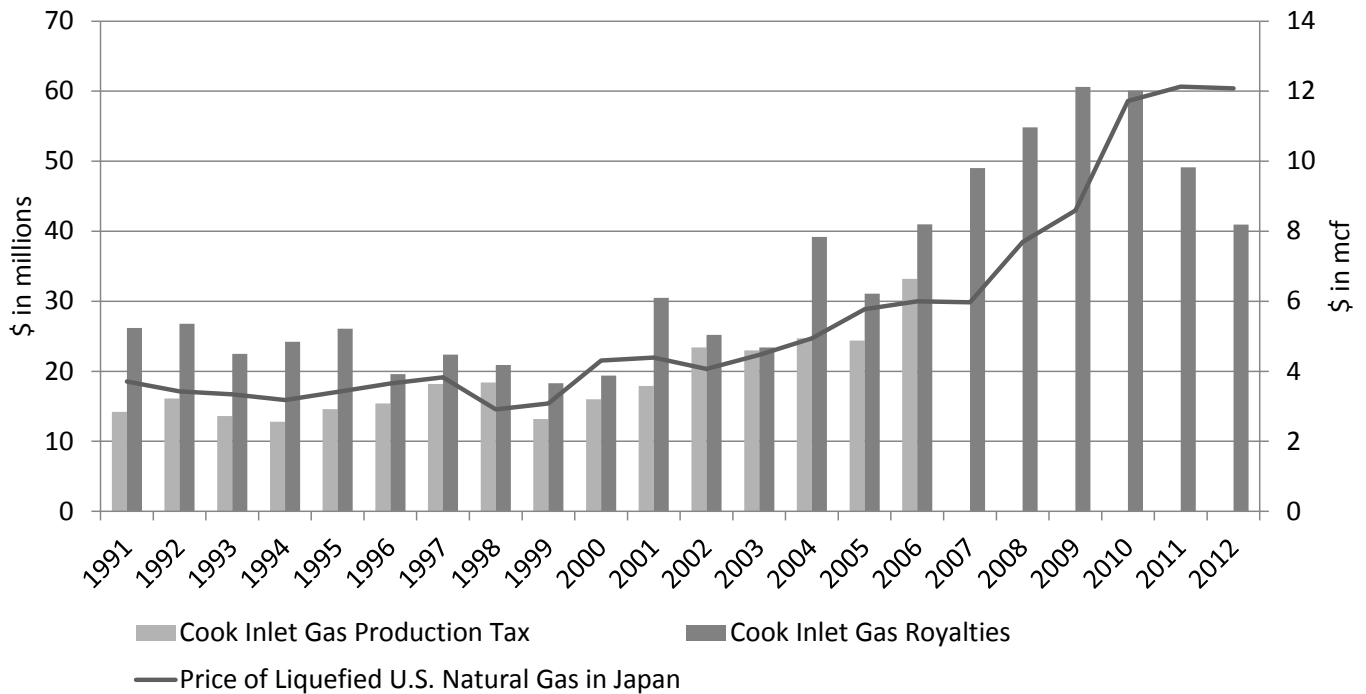
An expanded use for natural gas is a part of the discussion about the energy use mix within the State, especially in terms of electricity generation. Should North Slope gas be delivered to south-central Alaska or Cook Inlet production increase, at a competitive price, at sufficient volumes, new uses are proposed for natural gas within the State. For example, several mining projects have proposed using natural gas to power their operations. The developer of the Donlin Creek gold

mine, a major prospect located near Bethel in Southwest Alaska, proposed constructing a 312-mile-long pipeline to the mine to generate power. Pebble Partnership proposes using natural gas in its concept plan to power mine operations. This is also coupled with the thought that such a gas supply could provide a cleaner and cheaper fuel to generate electricity for the larger region, which currently relies mainly on fuel oil that is barged in. Also, any electrical energy generated in Anchorage can enter the Railbelt regional grid benefiting even the Fairbanks area population. LNG imports have even been considered should a regional source of natural gas be unavailable.

### **Past Plans for Alaska Natural Gas Export**

The Prudhoe Bay oil discovery in 1968 that led to the construction of the Trans-Alaska Pipeline System

**Figure 3-D: Production Tax and Royalty Collections on Cook Inlet Natural Gas and Japan Natural Gas Price**



Source: Alaska Department of Natural Resources

(TAPS) also included an estimated 26 trillion cubic feet of natural gas, which has been revised to over 35 trillion cubic feet of gas. Efforts to commercialize natural gas began soon after the completion of TAPS, and over forty years there have been numerous and even competing proposals to move North Slope gas to markets. However, to date, Alaska does not export North Slope gas, although natural gas is used for enhanced oil recovery and for electricity generation on the North Slope.

The use of natural gas on the North Slope is not insignificant. Producers are prohibited by law from flaring natural gas on the North Slope. Instead, they use it for power generation to support oil production. Since oil production began in 1977, 6 trillion cubic feet of gas has been used for power. Some natural gas

is produced as liquids that can be shipped through the TAPS along with oil. Since the completion of the Central Gas Facility in 1986, over 600 million barrels of gas liquids have been produced. Some of the gas is turned into a “miscible injectant” that helps increase oil production. The remaining gas is re-injected into the Prudhoe Bay reservoir to maintain pressure and help increase oil production.

In 1976, Congress passed the Alaska Natural Gas Transportation Act, which provided for expedited development of a pipeline. The following year, the United States and Canadian governments approved the construction and ownership of a pipeline along a route that followed the Alaska Highway through Canada to reach Continental US customers. A competing project at the time included the El Paso Natural Gas

project to export LNG to California, also called the “All-Alaska” route (a name used later by other Alaska projects that follow a similar route), to a marine terminal near the oil terminal in Valdez, Alaska that was rejected under the same federal certification process that approved the Alaska Highway route. Even an “over-the-top” offshore route in the Arctic Ocean to Canada and ultimately to US East Coast markets was proposed at the time.

Deregulation of the US domestic natural gas industry led to a supply increase and a price drop for the destination markets in the Lower-48 and the Alaska Highway project never materialized. In the end, none of the projects were able to answer the ultimate question to investors and project organizers: did the margin between the delivered cost and the expected price per unit of

gas result in sufficient net returns to justify the risk? In 1983, these costs needed to beat about \$3.00 per thousand cubic feet of gas in real 1983 prices, while annual average wellhead prices hovered above \$2.50 per thousand cubic feet. By 1986 were less than \$2 per thousand cubic feet. Only the southern leg of the planned Alaska Highway route was constructed, allowing gas from the Province of Alberta to help meet Continental US demand. Natural gas wellhead prices only passed the nominal \$3 per thousand cubic feet threshold in 2000.

Studies done in the 1980s revived a proposal to establish an LNG export operation for North Slope gas to Asia, but prices failed to support the commencement of such a project. Interest in a gas pipeline picked up again around the turn of the millennium due to rising prices and demand in the Continental US, primarily in using gas in electricity generation. In 1998, the Alaska Legislature passed the Alaska Stranded Gas Act Development Act, which allowed the State to negotiate special fiscal, tax and royalty terms, and regulatory terms with the North Slope oil producers, for an LNG project that exported “stranded gas,” defined as gas that, “... is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the Department of Revenue commissioner for a particular project.” The act was reauthorized

**Table 3-1: North Slope Gas Potential**

Exploration Area	Mean Technically Recoverable Gas (trillion cubic feet)
Prudhoe Bay	23
Point Thompson	8
ANWR	9
Beaufort Sea OSC	32
Chukchi Sea OCS	77
Colville-Canning Area & adjacent state waters	38
NPR-A	53
Total	240

Sources: U.S. Department of Energy, August 2007; BOEM, *2011 National Assessment*. Energy Information Administration, *2009 Annual Energy Outlook*.

in 2003 and extended to any North Slope gas pipeline project.

In 2004, Congress passed the Alaska Natural Gas Pipeline Act, which established a federal project coordinator, provided for loan guarantees, and offered tax and regulatory incentives for a pipeline project. These laws led to negotiations between the State administration and the producers that culminated in a contract in 2006 that was rejected by the State Legislature. At this time, annual average nominal wellhead prices in North America exceeded \$6 per thousand cubic feet.

In 2007, the State Legislature passed the Alaska Gasline Inducement Act (AGIA), which provided for partial reimbursement for a developer’s expenses, up to \$500 million, in exchange for agreeing to terms including following the State’s timeline. TransCanada, a Canadian pipeline company, was awarded the license on the project, and

ExxonMobil later agreed to work with them on the project. Meanwhile, BP and ConocoPhillips launched a competing proposal, called Denali – The Alaska Gas Pipeline. The plans in their various incarnations called for a pipeline to Canada to link into mid-American markets that were similar to the Alaska Highway proposals of the 1970s.

Falling natural gas prices in the Continental US due to the explosion of shale gas production drastically increased the North American supply within a period of a few years. In

2012, the three main North Slope oil producers, and owners of North Slope natural gas resources, joined together to propose a pipeline to a south-central Alaska LNG facility that would export gas to Asian markets, rather than a pipeline to North American markets. Work continues on this plan, and a preliminary concept was selected in early 2013. The current proposed project is reported to have an estimated cost of between \$45 and \$65 billion for a gas treatment plant, a 42-inch pipeline, and an LNG export facility (three trains delivering 15-18 million tons of LNG) in Nikiski on the Kenai Peninsula.

Two other LNG proposals include a recent proposal from Japanese company Resources Energy Inc. (REI) and an older proposal, by the Alaska Gasline Port Authority (AGPA), a joint venture organized in 1999 between the Fairbanks North Star Borough, Valdez, and, at one time, the North Slope Borough. The

port authority project applied for an export license, but the proposal was rejected in 2013 by the Department of Energy.

Parallel to these efforts to construct a large-diameter pipeline is an effort to construct a smaller pipeline to transport North Slope natural gas, to serve the local needs of Alaska consumers in the south-central area. In 2002, Alaska voters approved a ballot measure that created the Alaska Natural Gas Development Authority (ANGDA), which was vested with the authority to act as a shipper and obtain financing for a project. In 2010, the Legislature created the Alaska Gasline Development Corporation (AGDC), as a subsidiary of the Alaska Housing Finance Corporation. AGDC was tasked with moving forward with the Alaska Stand Alone Pipeline (ASAP) project to build a line. In 2013, the Legislature made AGDC an independent corporation and folded ANGDA's operations into it. The AGDC project itself reports a cost estimate of \$7.7 billion for a 36-inch pipeline to Anchorage and a gas conditioning facility on the North Slope \$4.9 and \$2.8 billion, respectively.

## Natural Gas Markets

The physical requirements needed to transport natural gas dictate the manner in which it is marketed and used. Countries or regions that have deposits of natural gas and have well-developed natural gas pipeline networks are able to move the gas to where it is needed. Countries or regions without natural gas or use more natural gas than they produce, must import gas either by pipeline or must import LNG at a marine

terminal. An example of the former is Germany's use of Russian natural gas that is delivered by large-diameter pipeline, and an example of the latter is Italy's import of Algerian gas by sea. South Korea, which has little domestic gas, but has a well-developed national gas pipeline network, is able to import natural gas through three injection points and distribute it relatively efficiently throughout the country. In contrast, Japan has a very rudimentary national pipeline network, and relies on over 20 marine terminals to accept natural gas. The electrical utilities own most of the LNG import terminals and the natural gas is used to generate electricity, which is then distributed throughout the country. Rigid right-of-way laws have made the establishment of a gas pipeline network problematic.

Globally, the major distinction, therefore, is between natural gas that can be delivered by pipeline overland and natural gas that is sold as LNG by sea. Historically, Alaska's natural gas, produced at tidewater in Cook Inlet, was a natural candidate as an LNG export project.

However, projects to export Alaska's North Slope gas are always faced by various options, including moving natural gas by pipeline to North American markets via a route to the closest major Canadian hub located in Alberta, known as the Alberta Energy Company (AECO) hub. Other options include moving the gas to a marine liquefaction plant for export to Japan or other markets in Asia, or, even to North American West Coast markets, which require the additional cost of constructing an import terminal at the destination. There have been other options

considered as well. There is the so-called "over-the-top" option, with a pipeline going due east along the Arctic National Wildlife Refuge, into Canada. This option would pick up Canadian arctic gas deposits, and be delivered to the previously high-priced markets of the US Northeast. This option is typically rejected because of difficult environmental permitting issues related to the federal refuge, and because the pipeline has a relatively short length within Alaska and the United States and has been couched as benefiting Canada disproportionately. In fact, there is a state resolution (HJR 44, 2002) and a federal law (Alaska Natural Gas Pipeline Act, 2004) that prohibits the "over-the-top option." There is the option of a shorter pipeline to the Bering Sea, or taking gas directly out of the Arctic on LNG vessels, but these options have significant technical challenges.

Either option requires significant lead time and large capital costs, and the construction of an overland pipeline either to Canada or to south-central Alaska. However, one option ties Alaska natural gas directly into North American markets and the extensive pipeline network, while the other, would have Alaska continue as a player in the marine LNG trade. For the export of Alaska North Slope gas, the price differentials at various times would have one option seem advantageous over the other. However, over a thirty year period, the price differential between the two destinations has been large and small, and has reversed several times.

Globally, population centers and energy basins exist in different locations. Nowhere is this more pronounced than with the Asian

economies of Japan, Republic of Korea and Taiwan. Japan, as mentioned before, is unique since its gas supply comes into many different terminals associated with an electrical utility and the national pipeline network is non-existent. These three industrialized countries are the premium markets for LNG. In addition, China, India, South America, the Middle East, India and European countries represent new and growing markets for LNG. These new LNG demand centers have more energy options than Japan and Korea, resulting in weaker premium LNG prices in these locations. Yet, these regions are reliant on external LNG sources.

Basins located in Russia, Qatar, Australia, and others are the main suppliers to the global LNG market. Suppliers to the LNG market are set to rapidly expand. Up to 25 countries have proposed plans to build export LNG terminals or add additional capacity over the next decade. These additional exporters have little or no current capacity. Ironically, with LNG prices at unprecedented highs, Alaska, one of the first suppliers of LNG in the world, has ceased to produce and export LNG from Cook Inlet.

## Natural Gas Prices

To show how these markets interact and to get a picture of the current conditions of the global market for natural gas that are relevant to Alaska, we compare major natural gas pricing points – the US Gulf Coast Henry Hub (HH), the UK’s European National Balancing Point (NBP), and the Japan-Korea Marker (JKM).

Henry Hub, in Louisiana, is the

price hub that defines the market for North American pipeline gas in mid-America. Pipeline infrastructure defines natural gas markets in North America. Henry Hub natural gas prices are the most often quoted natural gas prices in North America. Natural gas pricing in North America is lucid, despite a large geographical area the infrastructure covers. With accessible infrastructure, large reserves, cutting edge production technology, stable governments, large numbers of suppliers and consumers, financial markets and other factors, have created an unparalleled distribution system. Extensive infrastructure coupled with a massive amount of associated gas produced along with the relatively new “shale oil revolution” in North America, the US currently has some of the lowest natural gas prices in the world. Only five years ago, this was not the case. Annual average prices were almost triple what they are today at the wellhead.

The National Balancing Point (NBP) is a virtual trading location and is a price point for British gas. Unlike Henry Hub, it is not a physical location. It includes North Sea gas into the UK and has both a pipeline and LNG natural gas market component. It is also the price and delivery point for the Intercontinental Exchange (ICE) for natural gas futures contracts.

The Japan-Korea Marker is Northeast Asia’s pricing point that consists of an LNG import market connected to South Korea’s national pipeline system, and the large number of marine terminals in Japan where the natural gas is directly converted into electricity.

Japan LNG also supplies a relatively inefficient city gas market.

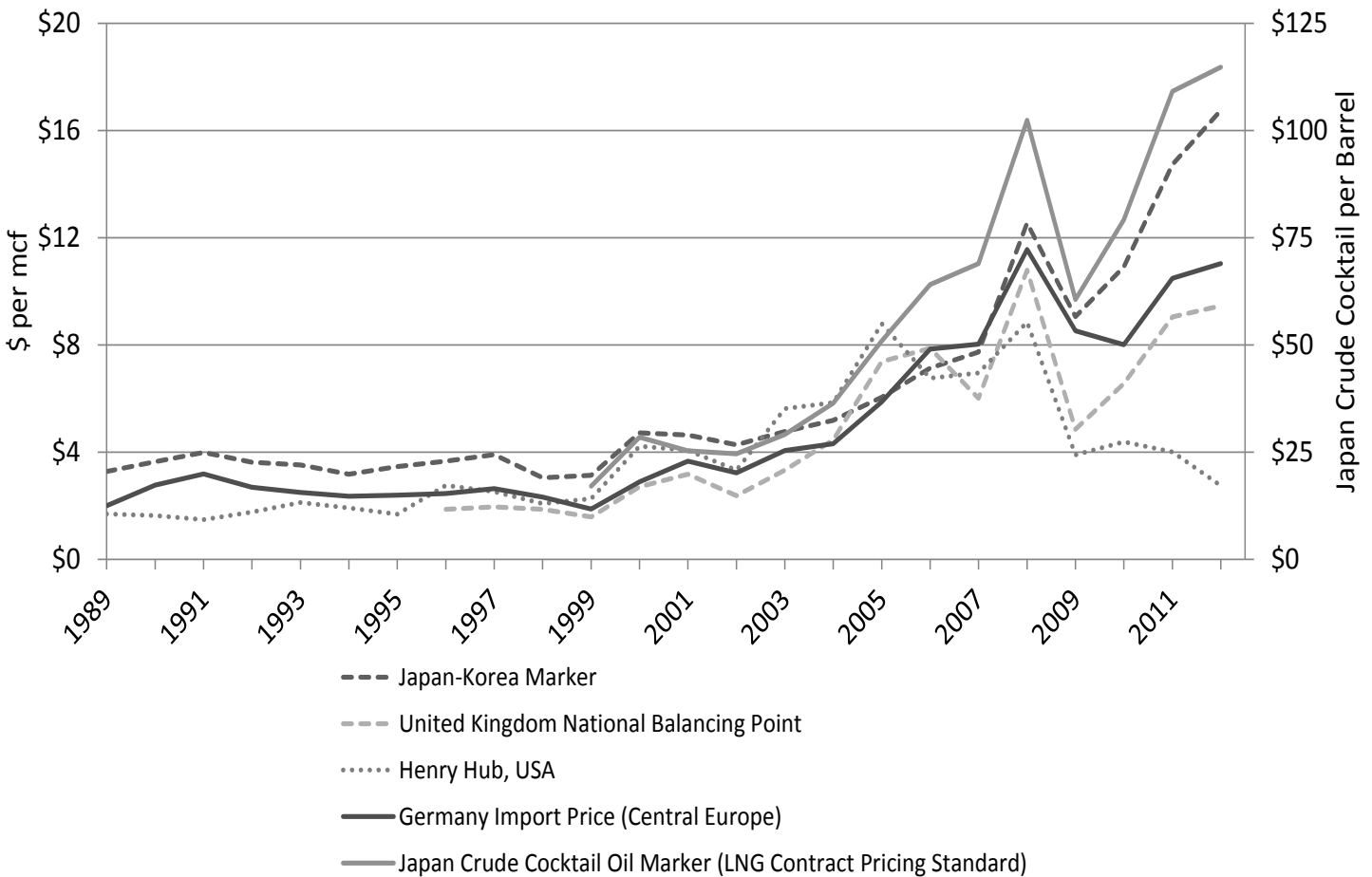
Figure 3-E illustrates natural gas prices globally, including a comparison with oil, on an equivalent thermal basis.

While the global gas price hubs continue to follow oil prices, Henry Hub notably does not. In general, the major price hubs have experienced significant divergence in price. Until 2007, these markets normally traded within \$2-\$3 of each other. Currently, the pipeline market and the LNG market differentials have never been greater, consistently exceeding \$10. The current divergence between Henry Hub and the Japan-Korea market differs by more than five times.

In the 1990s, natural gas prices in North America were relatively low and stable, and natural gas became extremely popular in electricity generation because it was a cheaper and cleaner burning fuel, relative to coal and oil. On the demand side, the US deregulation and restructuring of the natural gas industry expanded the use of natural gas in the US energy mix. On the supply side, prior to 2007, natural gas production was mainly tied to discoveries linked to oil, creating a structural relationship that existed between oil and natural gas. Oil prices started to rise in 2003 due to loss of spare capacity in the oil market, strong global growth and underinvestment by petroleum companies accustomed to a low oil price environment. Further, US supplies were constrained primarily to domestic supplies, since LNG import terminals were relatively insignificant as a source of supply.



**Figure 3-E: Global Natural Gas Prices**



Sources: BP's 2013 Statistical Review of World Energy, Bloomberg, and Reuters

As demand grew and supply was constrained, the result was a sharp increase in natural gas price in US markets.

Incidentally, the 1990s coincided with proposed plans to bring Alaska LNG into the California markets. One problem was the difficulty of permitting an LNG import terminal in the Continental US. Another problem was that shipping Alaska LNG would require vessels constructed and operated under

Jones Act requirements, considerably more costly, considering delivery to higher priced Japanese LNG markets could be delivered in foreign vessels, with foreign crews.

After 2007, the oil and gas industry in North America increased investments in developing new resources of natural gas from shale. Prices in North America collapsed, further exacerbated by a lucrative market in stripping natural gas liquids (a high price commodity

relative to gas), leaving behind a large supply of relatively low price natural gas. See Henry Hub prices in Figure 3-G. At the same time, in addition to Henry Hub prices diverging from other prices, the Japan-Korea Marker and National Balancing Point pricing diverged due to the way LNG contracts link to oil price markets. National Balancing Point price increases have been muted when compared to Japan-Korea Marker prices, which are heavily influenced

<sup>(1)</sup> NBP has both LNG and pipeline gas supplies resulting in gas on gas competition. Europe also has a wide variety of sources to obtain supplies, which include North Africa, Middle East, European sources and Russia, in other words Europe is a marginal consumer of LNG. Pipeline gas prices from Russia to Germany and central Europe did not fall as far. Gazprom, the Russian national gas supply company, was able to maintain prices due to its dominance in the European market. Gazprom is now facing an anti-trust case launched by the European Commission.

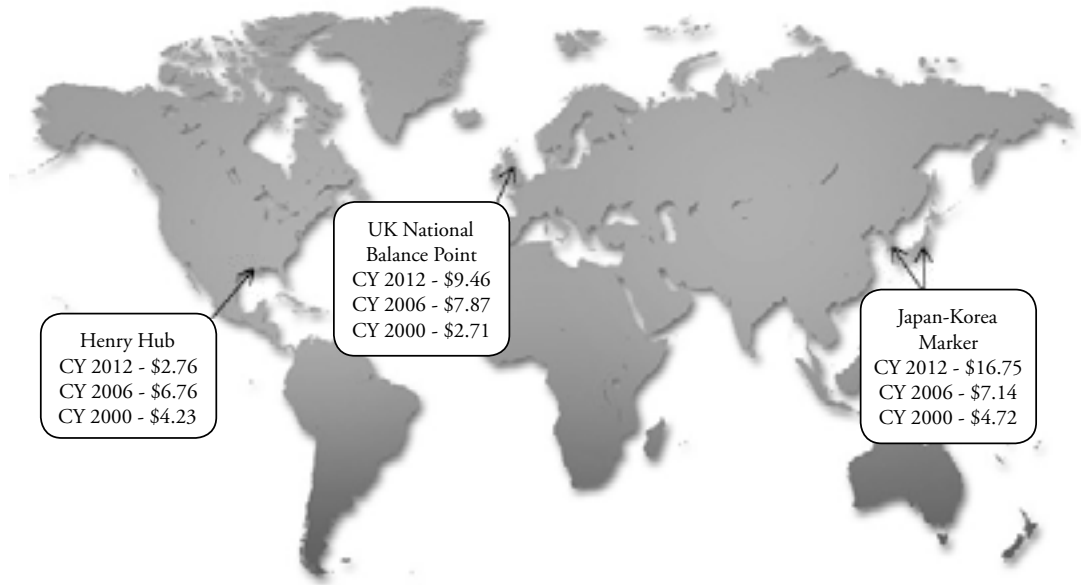
by oil linked contracts.<sup>(1)</sup>

Natural gas prices in Alberta have always been important to Alaska, since this would be the likely destination for any Alaska gas overland pipeline project that delivers gas to the Continental US. The differential between Louisiana and Alberta prices is the cost of transportation between natural gas coming from Alberta to Louisiana. This is a sign of a mature market with ample infrastructure. All other natural gas hubs in the US and Canada are based upon either

of these hubs, plus a differential to reflect regional dynamics. Prices for natural gas vary in different regions, determined by local factors such as the number of competitors selling gas, regulatory bodies, pipeline capacity, industry, abundance, substitute energy sources, etc. Currently, the processes within the US that have reduced natural gas prices are also at work in Canada.

For Alaska, price volatility (especially from the 1990s through today) has greatly affected project economics of a North American gas pipeline. In the ten years it takes to complete an Alaska project, natural gas prices could change dramatically. See Figure 3-F a geographic view of price differentials. Reduction of pricing risk is critical to the success of a pipeline from the North Slope. Regional price dynamics play a critical role in determining the final destination of the gas. Ideally, gas would be delivered to a population

**Figure 3-F: Geographic View of Price Differentials**



Source: BP's 2013 Statistical Review of World Energy

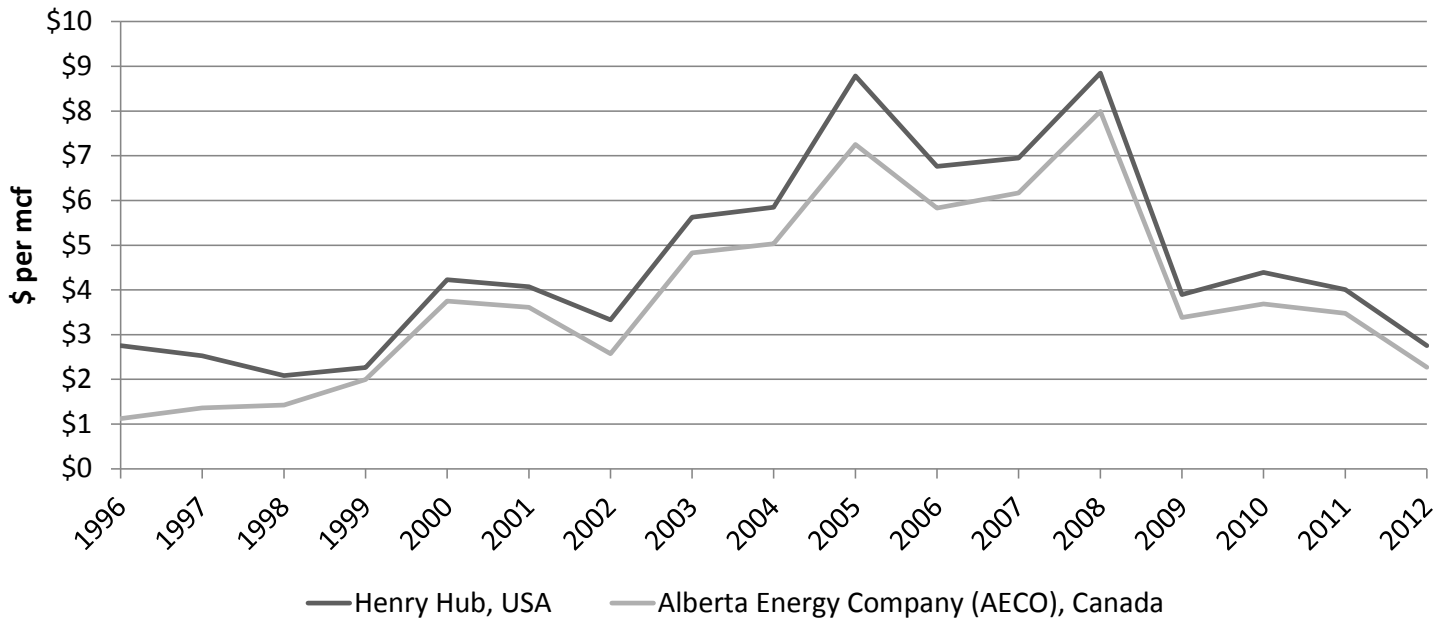
center isolated from large supplies of natural gas and that has ample demand. The location of where the gas is delivered is important as it relates to the two major pricing hubs in North America and the route the gas takes to get there.

The relatively cheap natural gas price in North America has now made it a major fuel in electricity generation. In fact, cheap natural gas burns cleaner than coal, producing 70% lower carbon emissions. This advantage has allowed natural gas to capture more of the electricity market in the US. As Figure 3-H illustrates, between 2000 and 2011 the market share of coal has decreased and natural gas market share has increased. This trend is set to continue as America's oldest electricity plants that run on coal are being retired, and are replaced by natural gas plants.

## LNG Demand

Global LNG demand has grown 7.6% per year since 2000, compared to global natural gas demand growth of 2.7% over the same time period. Asia has been the single largest contributor to this rise in demand for LNG. The Fukushima reactor meltdown has anchored LNG growth in the short- to mid-term as Japan has moved away from nuclear energy for current and planned incremental electricity generation. LNG demand seems to be set to continue expanding as nations seek energy diversification and flexibility in their energy sources. There is also a growth in infrastructure within Northeast Asia and India that allows LNG used, and there is a regional concern for hydrocarbon emission and the desire to replace coal with the cleaner burning gas. Finally, there is a surge of supply as new basins are brought online to serve

**Figure 3-G: Major North American Hub Prices**



Source: BP's 2013 Statistical Review of World Energy

the LNG demand in Asia. Europe, which has spent years developing a de-carbonization strategy, with Germany's rejection of electricity generation by nuclear energy, also a reaction to the Fukushima disaster, has not had subsequent increase of use of natural gas in electricity generation. This is primarily because Germany is one of Europe's main energy consumers and Germany's main supply of gas, by pipeline from Russia, faced the monopolistic pricing policy of Russia's state-owned gas production giant, Gazprom. Ironically, coal use in Europe has increased to compensate for the shut-in nuclear capacity.

The International Energy Agency (IEA) predicts strong global growth of natural gas usage. IEA's forecast for natural gas in 2035 is 25% of energy consumption, up from 21% in 2010. Global natural gas demand is projected to grow 1.6% per year,

whereas oil growth is projected to rise at 0.8% annually over the same time frame. Estimated LNG demand in 2030 is 24,000 bcf, double 2012 demand of 12,000 bcf. LNG demand is forecast as particularly strong through 2020, with a broad range of analysts and observers projecting 5%-6% growth per year.

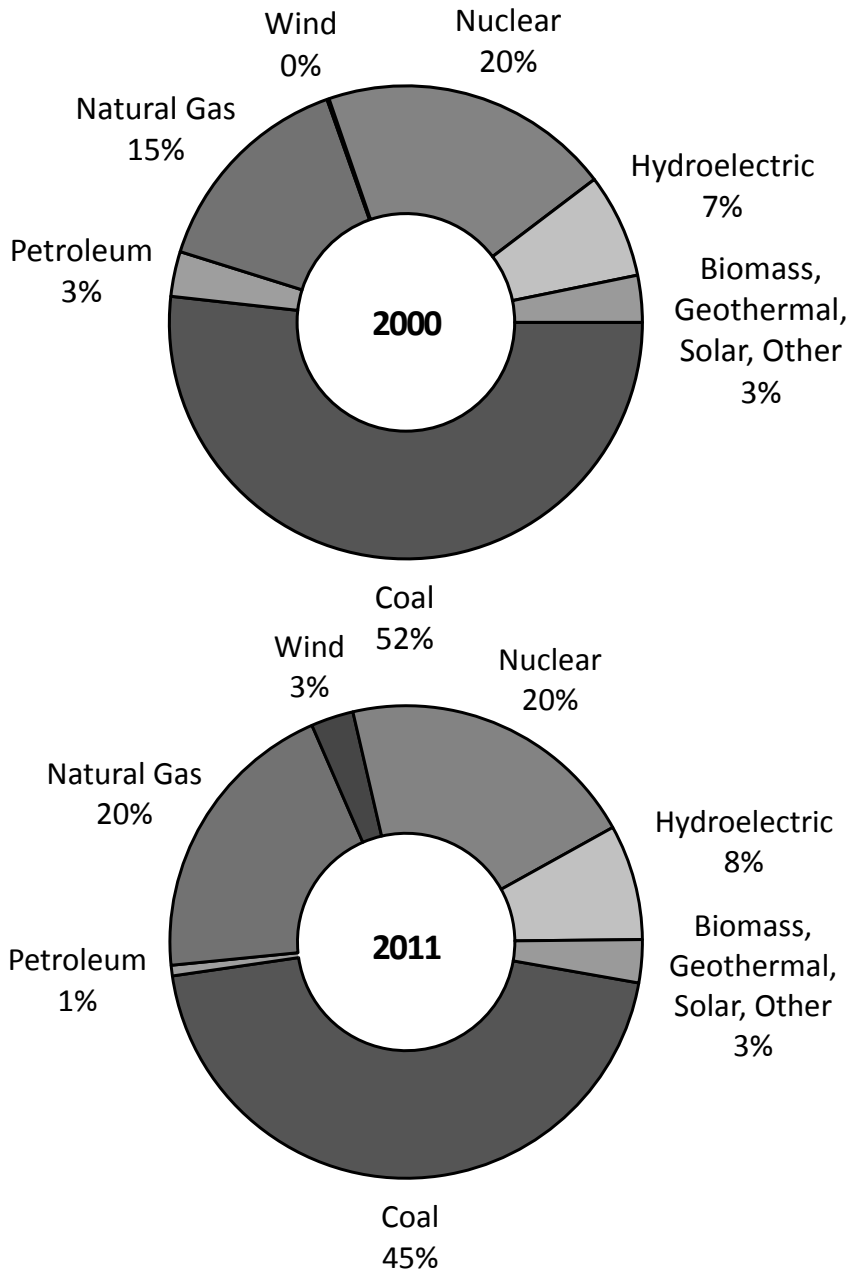
Currently, half of LNG market demand comes from Japan, Republic of Korea (South Korea) and Taiwan. These countries are classified as being heavily industrialized with limited domestic energy resources and are expected to remain the major drivers of LNG demand in the future.

New LNG demand is led by China and India. China's latest five year plan doubles the amount of LNG used from 4% when the plan came out to 8% in 2015 and 10% by 2020. In order for China to meet the goals of its "five year plan," coal consumption

must decline, likely to be replaced by LNG. Currently, China's coal consumption is seven times larger than the global LNG trade. In contrast, US coal consumption for electricity generation decreased by 26% between 2007 and 2012, according to the EIA. China does have natural gas opportunities to develop, including shale gas and pipeline gas expansions, and it has pursued these opportunities aggressively. If China's natural gas demand continues to grow, pipeline and shale gas production volumes will need to be supplemented by increased LNG imports. With multiple supply options, China should be well-supplied by domestic sources, pipeline gas and LNG contracts. Figure 3-I illustrates China's projected LNG imports.

Other countries have planned new construction or to add additional capacity to import LNG. Many

**Figure 3-H: U.S. Electricity Fuel Sources 2000 and 2011**



Source: Energy Information Administration

of these countries will be new importers. Currently, there are 25 countries that import LNG with a regasification capacity of 28.8 trillion cubic feet per year; and, by 2020, 38.4 trillion cubic feet per year of regasification capacity could exist, an

increase of 9.6 trillion cubic feet, or 33% over current capacity.

### LNG Supply Risks

Uncertainty is the key term the LNG supply chain faces. Challenges

exist in multiple forms on a global scale, from competition to unwieldy expensive large projects, and local to global economics. Since 2009, global economic growth has been slow to emerge. Many economies within the Organisation for Economic Co-operation and Development (OECD)<sup>(1)</sup> have yet to recover fully, with non-OECD countries growth being restricted because of this. LNG projects are handicapped with this uncertainty, even though current economic trends suggest that the global economy has stabilized and economic growth has returned.

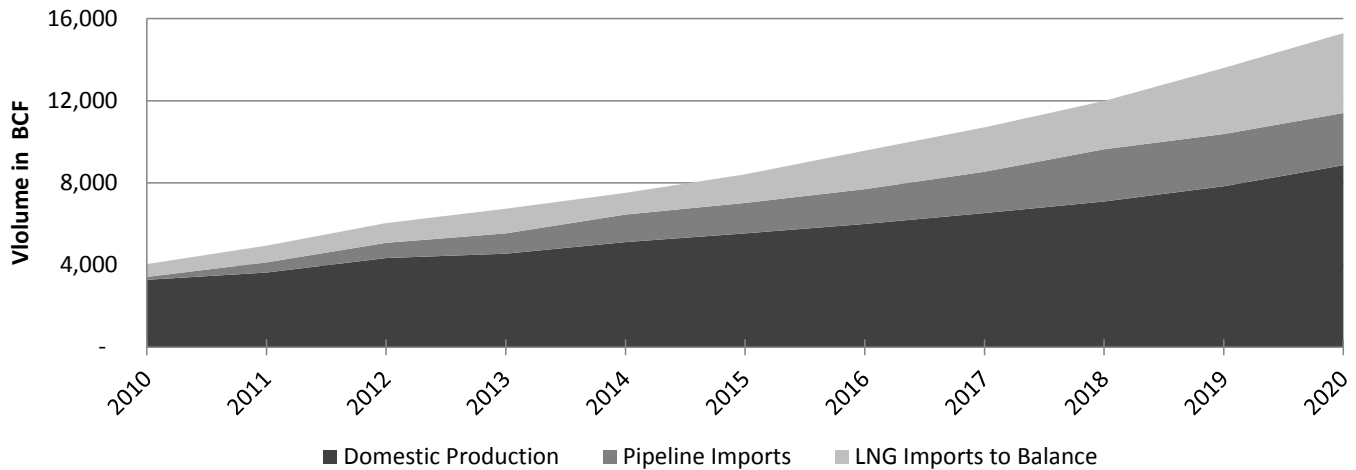
New supplies from unconventional resources such as shale gas, coal bed methane, tight gas and methane hydrates could capture potential future LNG market share. These unconventional sources also exist on the North Slope of Alaska. Ten years ago, the estimated natural gas resource base worldwide was for 50 to 60 years' worth of supplies. Now the natural gas resource base is projected to have expanded to a 200 year supply. The IEA estimates there are 752 tcm of technically recoverable natural gas world-wide.

### LNG Supply - Capacity

Global LNG capacity has developed in stages. In addition to Alaska's Cook Inlet, early LNG exporters included Algeria, Indonesia, and Malaysia, followed more recently by Australia and Qatar. The early LNG exporters still control about 60% of the global LNG supply, with Australia and Qatar providing 20% of the market. This market structure is expected to shift dramatically by 2020. Algeria, Indonesia, and

<sup>(1)</sup> The OECD economies are the world's industrialized economies.

**Figure 3-I: Chinese Natural Gas Supply Sources**



Source: Ernst & Young Global LNG “Will new demand and new supply mean new pricing?” 2013

Malaysia market share will drop to about 20% on a global basis by 2020. While Australia and Qatar are expected to expand their markets share to about 50% globally.

Australia in particular has a number of LNG projects under development representing a third global wave of projects. These green field projects will have the capacity to produce 2.8 trillion cubic feet annually.

### LNG Supply – New Entrants

Any Alaskan LNG project must evaluate future competing LNG projects worldwide. LNG projects under construction and those projects currently supplying the LNG market are not Alaska’s competitors. Those LNG projects have clients, the development costs have been partially or fully funded and risks have been resolved or negated to an acceptable level. Longer term, suppliers to the LNG market will expand as new entrants enter the market. There are up to 25 new countries who currently could become entrants to the global LNG market. Possible new

entrants include Canada, United States, Tanzania, Mozambique, Israel, Iran, and Venezuela. Some countries like Iran and Venezuela are less likely to develop their reserves due to geopolitical events and financial constraints. Other countries like the US and Canada are in much better position to begin exports.

Future LNG projects all face unique risks. Israel’s natural gas reserves are subject to national security matters. Tanzania and Mozambique proposed LNG projects have no supporting infrastructure, contain security risks and are located far offshore. Canadian LNG terminals face an uphill battle due to multiple projects competing for the same market, environmental opposition, and resource constraints if multiple LNG plants are all constructed at once.

Under current conditions an Alaska project also faces significant risk, some of which would have to be mitigated to have an LNG project move forward. This may be a strategy to provide a win-win situation, where

producers have an economically viable project, Alaska’s economy is more diversified, and state revenues are diversified and increased.

### LNG Supply – US, Canada and East Africa

The Department of Energy (DOE) must issue an export license to any US LNG export terminal according to US law. As of January 2013, there are 20 companies who have applied for an export license from DOE. Licensing for LNG exports falls into two categories, countries with whom the US has free trade agreements (FTA) and non-FTA countries. Sixteen projects have received approval to export to FTA countries and one project has non-FTA country approval. South Korea and Singapore are the only FTA countries with significant LNG demand.

Nine US LNG export facilities have infrastructure already in place. These facilities were originally designed for LNG imports. They were planned just before the advent of widespread shale gas, as a way to alleviate North

American supply constraints in the 2000s. These “white elephant” import facilities are being converted to export facilities. Conversion of this existing infrastructure into export facilities represents cost savings in comparison to new LNG facilities and creates revenue opportunities from otherwise money-losing infrastructure.

The proposed export projects represent 10.2 trillion cubic feet of LNG export capacity. It is very unlikely all this capacity will be built, as global demand was 12.0 trillion cubic feet in 2012.

Cheniere’s Sabine Pass LNG export terminal in the Gulf of Mexico is the only project near export production and its gas is all under contract. Originally, it was constructed as a LNG import terminal. Sabine Pass has export capacity of 864 bcf annually. The project has four anchor buyers and there is some gas reserved for spot sales. Contracts for buyers are structured on Henry Hub gas prices, a 15% uplift/shrinkage charge, and a fixed liquefaction charge. It is these Henry Hub structured contracts that are of great interest in the Asian markets and are of great interest in relation to the traditional oil-denominated contracts.

There is intense interest in exporting LNG from Western Canada. There are four projects planned, representing 2,400 bcf of annual capacity. These projects are based on large natural gas resources located in Western Canada, supportive government policies and openness to

foreign investment. These projects are expensive, costing tens of billions of dollars. Each project is a greenfield development, from the wellhead to the LNG export terminal, meaning everything has to be built from the ground up. Developers of the projects will own every aspect of the LNG project, requiring extremely large capital investments upfront. The basins these potential projects will access include the Montney, Horn River, and Liard. Pipeline investments alone are expected to add \$200 million to project costs.

Individual projects are worth noting for their strengths and weaknesses. There are two projects are located in Kitimat, British Columbia. The largest project is the Shell led consortium, with a planned LNG export facility of 1,150 bcf annually. Shell’s partners include national oil companies (NOC) Petrochina, and Kogoas, along with Japanese conglomerate Mitsubishi. The competing, Apache’s consortium, that also includes Chevron, is planned with a capacity to produce 480 bcf annually. Chevron brings extensive LNG experience, financing, and a clientele of existing customers. Chevron has publically stated oil linked prices are necessary for the project to be successful, while LNG importers are likely to challenge this stance.

Offshore of East Africa, there have been a number of extremely large natural gas fields found in a lightly explored area. Most of the confirmed natural gas finds have occurred in Mozambique, with more recent

finds in nearby Tanzania. There is an estimated 110 trillion cubic feet of natural gas in Mozambique alone. Project economics are dependent upon clustering of infrastructure to reduce costs, requiring cooperation between the ENI led consortium and the Anadarko led consortium. LNG export capacity from this area is unknown at this time since no project plan has been developed. Other considerations for the companies at this point are securing LNG export licenses, funding, clients, fiscal terms and cooperation between the different stakeholders.

## LNG Economics

LNG projects are expensive, and often financing is sought for the entire LNG chain from wellhead to shipping. Suppliers of future LNG look toward clarity in pricing to justify the economics of these projects. Early LNG projects before 2003 cost less than \$4 million/bcf annually. The second wave of projects cost between \$10 to \$25 million/bcf annually. Now projects under consideration are in the \$54 million/bcf annually range according to Deutsche Bank.<sup>(1)</sup>

Analysts at Credit Suisse expect several proposed LNG export projects to be built in North America and Africa.<sup>(2)</sup> Economics of these projects compare favorably to the Australian projects being developed. The US and African projects have an estimated cost of \$96 thousand per bcf per year, versus \$144 thousand per bcf per year for Australian projects. Australia’s economics did not look to be at

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<sup>(1)</sup> Deutsche Bank. *Oil and Gas for Beginners Industry Update*, 25 January 2013.

<sup>(2)</sup> Credit Suisse. Global Equity Research, *Global LNG Sector Update*, 7 June 2012.

such a disadvantage when the decisions were made to develop the LNG projects. Currency risk has hit Australian projects hard, as the Australian dollar has appreciated more than 60% against the US dollar since 2009, as has the shortage of specialized labor.

In order to offset these very high risk and extremely capital intensive projects, suppliers want iron clad LNG contracts linked to oil prices. Traditionally, LNG contracts were linked to oil prices, with Japan, Korea, and Taiwan willing to accept these contracts for imported LNG in order to diversify their energy sources. However, there may be less willingness to accept this standard going forward. LNG is developing a market as a separate commodity from oil and some analysts suggest that the LNG market will continue being more competitive in the future, although this view is far from universal. The LNG market views oil as becoming scarcer and higher priced and LNG becoming more plentiful making the linkage between the two undesirable, especially in the long-term. A response to this is the shift from oil-indexed contracts to Henry Hub based indexing, which is now growing popular in Asia.

The LNG market is following a classic trajectory toward market equilibrium. Suppliers looking at developing expensive projects need high prices to justify their development. At the same time, more price sensitive buyers are unwilling to commit to expensive long term contracts. The result has been buyers signing shorter-term contracts and strict oil indexation is faltering. Again, an example of this is the preference in Asia for Henry

Hub based contracts over traditional oil indexing.

Longer term market prices and oil based LNG prices should migrate away from each other, as suppliers of LNG will be forced to compete on price in order to remain competitive. However, the relationship between the two will likely not collapse. In order to guarantee supply, importers of LNG will pay a higher price. The same relationship holds true in the oil market. Excess capacity exists, but there is a premium built into price to ensure adequate future supplies.

The development of a more active spot market pricing for LNG would be a major next step for pricing. The development of a trading hub where supplies can be physically delivered and picked up, will increase liquidity and support the development of an active financial market. An active spot market will provide price clarity to all market participants. Singapore is the leading contender in Asia for the actively traded physical and financial market to be located. The terminal in Singapore will have both import and export capacity, enabling it to fulfill this role. Currently, weak pricing signals exist in the LNG market as pricing transparency is hindered by contracts and their terms are obfuscated.

A contrary argument is that the considerable investment for each project makes it untenable for financing should the market not remain with a predominance of long-term contracts. A sign of a mature market is when risk based premiums for commodities weaken. Instead global LNG players emerge with a portfolio of places LNG is sourced from and this is sold to a

portfolio of buyers. Major energy companies like BP and Chevron are already participants in this market development. These portfolio players will be able to sign contracts where greater flexibility will exist for a cargo's timing and delivery location. When this happens regional prices for LNG should start to converge on global price, due to arbitrage.

Even a well-developed spot market will not spell the end for LNG risk premiums. Spot markets for Henry Hub prices have had tremendous price movements. Volatility in LNG prices will force LNG suppliers to have higher rates of return in order to justify new projects.

### **Financing Large Natural Gas Projects**

Large project financing follows a straightforward formula. A project is identified, passes the project partners internal hurdles for investment, and project partners set up a separate entity to reduce risks to them. The newly created entity is funded with an equity contribution from each partner and debt issued by the new entity. Capital raised is used exclusively to fund the project through project completion. Cash flows from the project are the only means of repayment of debt and any excess capital is returned to the project partners, if the project is successful.

### **Risks**

Benefits of establishing a separate entity for a large natural gas project are centered on risk management. Project risks are considerable. Risk mitigation strategies include debt default protection, clear project funding sources, separate accounting,

limiting environmental liabilities, political risk, transportation risk, counterparty risk, supply risk, commodity risk, technology risk, inventory risk, taxation risk and other risks the project would encounter. These risks can be independent, dependent or interdependent on other risks the project faces.

A key question becomes how projects can reduce risk exposure. One way is through the assistance of government.

### Government Incentives

Large projects often require the cooperation of both industry and government. These projects can carry benefits for both industry and government. Governments can assist in making projects more attractive for financing in many different ways (as shown in Figure 3-J).

Governments have worked collaboratively on several important projects around the world. Included here is a discussion of planned projects in Russia, British Columbia, Australia, and Norway.

#### Russia

The Yamal Peninsula on the Arctic Ocean contains Russia's largest natural gas reserves, estimated at 55 tcm of natural gas. Russia's Novatek and France's Total looked to develop a green field LNG export project from the region. However, arctic conditions, high costs, long distances from customers and tax issues made the project questionable for development.

Russia is heavily dependent upon its natural resources for revenue and

**Figure 3-J: Government Incentive Programs for Major LNG Projects**

	Financial	Policy Assistance
<b>Direct</b>	Grants Subsidies Capital Investments Development Cost Funding Loans	Dedication of governmental natural resources Guaranteed off-take Expedited permitting Use of state property Condemnation power
<b>Indirect</b>	Income Tax Incentives Loan Guaranties Reduction in Fiscal Take Tax Credits Waivers of Property, Use, Sales, Franchise, and VAT taxes Use of governmental bond authority	R&D support Portfolio standards Demand incentives Fuel preference programs Consumer financial incentives Labor initiatives Building/zoning codes Interconnection planning Permitting standards

has substantial interests in the energy industry, including protectionist legislation and a mostly state-owned industry. Nevertheless, currently Russia has made the decision to cut taxes, approve LNG exporters other than Gazprom (the state-owned Russian gas company) and has provided other promises of assistance to ensure the export of Yamal gas. In 2011, the Russian government exempted LNG from the 30% minerals extraction tax. Other assistance from the Russian government will come in the form of financing of a port, an airport, gas pipelines, icebreakers, and dredging work. This assistance has an estimated price tag of \$9 billion. Regional governments are also assisting with the development, property tax exemption, and a lower Corporate Income Tax. These lower tax rates will expire once 8.8 trillion cubic feet of gas or 180 million barrels of condensate are extracted. Recently, foreign capital investment

in the project included China National Petroleum Corporation acquisition of a 20% stake from Novatek. A final development decision is expected in 2014.

#### British Columbia

Lack of infrastructure hinders the development of British Columbia's large natural resource base. Oil and gas deposits are located in remote areas, with challenging geography, and require large capital investments, and high degrees of uncertainty for any project success. Hopes for an LNG export industry are based on these greenfield oil and gas projects being developed. There are currently no LNG marine export terminals, although several are planned on the Pacific Coast.

Government supported incentives for development of these greenfield projects mainly revolve around royalty credits. These credits are for roads, pipelines and LNG export terminals. It is the intention of



British Columbia's government to generate more in royalties, than it spends in credits.

The framework for the credit program is based upon the original cost of the project submitted to the government before the project is started. Upon completion of the project the project can receive up to 50% of project costs as credits against royalties owed to the government. If a project cost \$1 billion, the developers would be able to take up to \$500 million in royalty credits.

As of June 2013, a total of \$1.7 billion was made in capital investments, including 1,243 new miles of road, representing 78 new resource roads, and 1,304 miles of new pipeline.

### **Norway**

Norway, like Alaska, is a mature petroleum production area with tremendous petroleum resources. The Snohvit gas field is currently considered as a source for LNG export. First discovered in 1984, the field took 23 years to develop. Located in the Arctic Ocean 90 miles from land, in 1,000 feet of water, the project had to confront some major obstacles and a new way of thinking about offshore development.

In order to develop the challenged Snohvit gas field, Norway reduced the tax burden on the project. Norway has a corporate income tax rate of 50% on profits generated by offshore production, plus 28% base rate paid by all corporations in the country. In order to enhance Snohvit's economics the 50% offshore tax was waived. This was done by allocating the profits from the offshore project to the onshore

LNG terminal. Another important taxation issue to consider, Norway allows for a six year depreciation schedule. A six year depreciation schedule enables capital cost recovery in a shorter time period, than in Alaska or at the US federal level.

Development of Snohvit required production equipment to be located on the sea floor with the gas piped onshore. Development costs totaled \$10 billion, well above the projected cost estimate of \$6 billion made in 2002. Snohvit has the capacity to liquefy 750 million cubic feet of natural gas per day.

## **State Tax and Natural Gas**

In Alaska, the production tax for natural gas is calculated in the same way that the tax is calculated on oil, with regional differences. The three oil and gas producing areas are 1) North Slope, 2) Cook Inlet, and 3) the rest of Alaska (collectively known as "Middle Earth").

The production tax levied on natural gas under AS 43.55.011(e) may be limited by statute and the limit is set to a certain derived price per thousand cubic feet based. Figure 3-K is a graphic that shows how the production tax is calculated for the three regions and highlights some of the similarities and differences. The distinction on the North Slope is that the tax is calculated is based on destination, whether the gas is used in-state or leaves the State. "Gas used in state" is defined per AS 43.55.900(24) as gas "delivered for consumption as fuel in state, including as fuel consumed to generate electricity." Not all gas used in state will qualify. For example, gas used

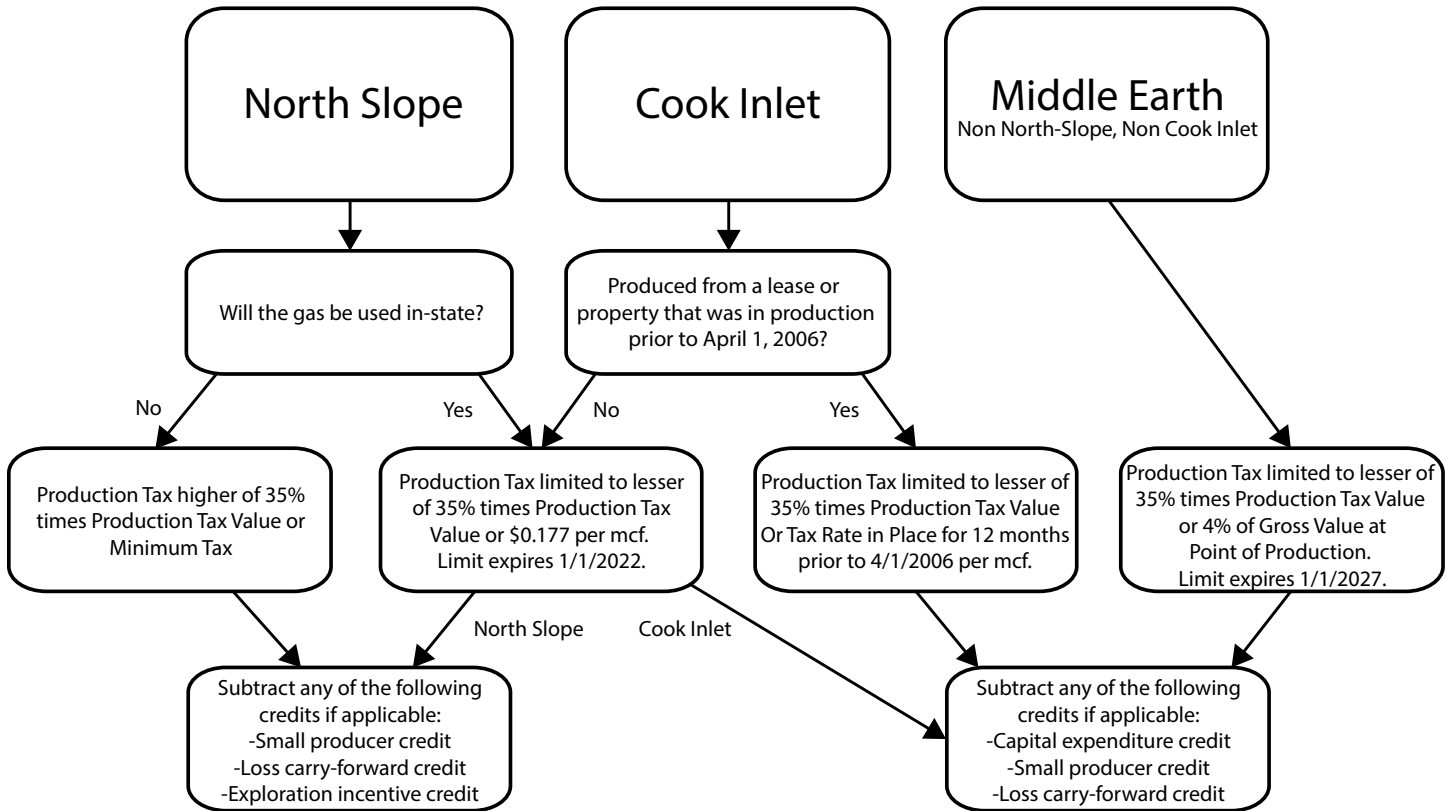
in manufacturing may not qualify. In Cook Inlet, the distinction for taxation is whether the gas is produced from a lease or property that was in production prior to April 1, 2006. Areas outside the North Slope and Cook Inlet have a maximum tax of 4% of gross value at the point of production regardless of destination, governed by AS 43.55.011(p).

For taxation purposes, natural gas volume is measured according to the average value per "barrel of oil equivalent" (BOE), a measure that equalizes the thermal value. Under the ACES tax regime, prior to January 1, 2014, including lower value gas in the same tax calculation as higher value oil reduced the progressive tax rate on oil ("progressivity"). By taxing oil and gas together, gas production reduces oil taxes even though oil operations are unaffected. This has been called the "flip the switch" problem. Under ACES, if major gas sales began, State tax revenue could have dropped significantly under certain price scenarios, including current prices. However, under the provisions of the More Alaska Production Act (MAPA), effective January 1, 2014, although oil and gas are still included in the same tax calculation, adding gas will not impact the tax rate on oil, since the legislation imposes a flat tax rate of 35%.

## **Conclusions**

Alaska's history of exporting LNG to Japan, producing fertilizer, and utilizing natural gas for local electricity generation and heating, provides the region with a long-term familiarization with the natural gas industry, including the LNG export trade. Even the analysis and discussion of several major

**Figure 3-K: Natural Gas Production Tax Calculation Diagram**



unfinanced and unconstructed natural gas export project plans over the years have provided Alaska with experts and policy makers with a better understanding of natural gas markets.

Natural gas remains an abundant resource within Alaska. LNG is natural gas that is in a form that can get to distant markets by marine transport. In deciding where Alaska North Slope natural gas should be sold, given the choice to go by land in a pipeline or by sea as LNG, the discussion should revolve around the destination price minus the costs of delivering a unit of gas over the lifetime of the project. The discussion also has revolved around the importance of profit made at the point of production, since this is where the current tax regime provides

revenue to the State. Other tax considerations include that the new tax regime has taken a step in dealing with the issue of “decoupling” oil and gas tax revenues to avoid diluting oil revenues with lower value natural gas barrels of oil equivalent.

Natural gas markets have changed dramatically within the last five years with North American natural gas prices falling and global LNG prices, especially in Asia, rising, resulting in a historic differential in prices in the market. At this time, the current price differential indicates a preference for exporting Alaska gas as LNG. However, new supply entrants are also planning to put their projects in the queue, as competing LNG projects take advantage of the current high price and supply shortfall.

In some cases, the new entrants

are supported with government involvement and support.

The window opened by current market conditions of natural gas and LNG might provide the necessary potential for new revenue, but up to now elusive, economic and commercial conditions for a North Slope natural gas project. Understanding the past and present conditions may give some insight for the future of Alaska’s natural gas resources.