Assessment of The Alaska Gasline Port Authority LNG Project

Prepared for The Alaska Department of Revenue
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Final Report

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1. Introduction & Mandate

1.1 Introduction

PFC Energy was commissioned by the Alaska Department of Revenue to conduct an analysis of the AGPA proposal in terms of cost, effect on North American natural gas markets relative to a US mid-continent destination and the likelihood of construction of the four planned LNG receiving terminals that have signed Memoranda of Understanding (MOUs) with AGPA to bring the project's LNG output into West Coast natural gas markets.

The Alaska Gasline Port Authority(AGPA) has proposed to take Alaska's voluminous North Slope gas reserves, ship them to Valdez and export it as LNG to the West Coast of North America. Included in the project is a spur line to deliver up to 500 MMcfd to Anchorage which, combined with 3.3 Bcfd of LNG equivalent for shipment to West Coast LNG receiving terminals, yields a sales gas volume of up to 3.8 Bcfd. The AGPA has executed nonbinding agreements with five LNG receiving terminal projects, four of which nominally remain in place. The AGPA has had Bechtel generate cost estimates for the project infrastructure located in the state of Alaska which was last updated in March 2005, and had secured several required project permits from the former Yukon Pacific project, which in the 1980s planned a similar project to export Alaskan gas in the form of LNG. These permits could have significant value to AGPA depending on project configuration and final liquefaction location. Substantial uncertainties remain with regard to the commercial arrangements on marketing gas within Alaska and as LNG.

1.2 Mandate

PFC Energy's mandate was to:

Assess the likelihood of the planned LNG import sites being constructed within the next ten years, including:

- Kitimat, BC
- Northern Star, OR
- Clearwater Port, offshore CA
- Port Penguin, offshore CA
- SES, Port of Long Beach

Assess West Coast gas marketing issues including determination of closest liquid gas market points and the cost of transporting regasified LNG to the first four of these points.

An LPG marketing assessment to look at the cost of transporting the project's LPG output from Valdez to Asia and the price it is likely to realize in both absolute terms and relative to the Chicago area.

Create a cost assessment of project facilities including liquefaction facilities, the pipeline to Valdez, gas processing and marine export facilities in Valdez, Jones Act-compliant LNG tankers where needed, and the first four LNG receiving and regasification terminals listed above.

Assess the need for Jones Act-compliant tankers for shipments to Kitimat, BC.

Estimate the effect on North American natural gas prices of AGPA sales into the West Coast relative to the sale of pipeline gas into the Chicago area, and a comparison of netback values to the North Slope of the AGPA project relative to Chicago based on PFC Energy gas market assessments and a pipeline tariff provided by the State of Alaska.

2. Executive Summary

PFC Energy's analysis of the AGPA project indicates that the project does not provide a superior netback value for monetizing Alaska's North Slope gas when compared to a natural gas pipeline to the Chicago area.

Below is summarized the key conclusions from the principal elements of the analysis conducted by PFC Energy.

West Coast Terminal Evaluation

- PFC Energy's evaluation of the Kitimat LNG project indicates that while it is likely to receive regulatory and environmental approvals, its relatively remote location means that it will receive significantly lower prices for regasified LNG than receiving terminals closer to major consuming centers in California. This is a disadvantage in both attracting LNG supply and maintaining high plant utilization during seasonal declines in demand. Given these disadvantages, the terminal is considered unlikely to secure financing for construction.
- The Northern Star terminal is also advanced in the regulatory process, and is well into the FERC pre-filing process. Its prospects for receiving environmental approvals are good, but not likely because of the volume of dredging needed by the project and concerns related to the release by dredging of toxic materials from sediments to the water column that then pollute fish consumed commercially and by Native Americans. Moreover the overall project's likelihood of receiving financing and beginning construction are poor because of the project's location and the limited market in the US northwest yield a significant risk that it will see seasonal variations in utilization or even be made redundant by rising Rockies gas production and other better positioned receiving terminals.
- PFC Energy's review of Clearwater Port shows that it has made little headway in the regulatory process for over a year and a half, and lags another nearby project considerably. Given the challenge of securing all regulatory approvals offshore from such a populated area and the progress of a direct competitor, PFC Energy considers the construction and operation of this project in the next ten years as unlikely.
- Port Penguin is to all intents and purposes a defunct project. Conceived by ChevronTexaco, the California Energy commission lists the project as terminated on its website according to the August LNG project update. PFC Energy considers the likelihood of construction and operation of this project in the next ten years as negligible.
- SES is well advanced in the regulatory process, but the California Energy Commission, the California State Lands Commission and the City of Long Beach have raised a number of similar objections relating the methodology of the threat assessment that, if applied, would make if very difficult to show that the project presents an acceptable level of risk to surrounding areas. Though PFC Energy expects that FERC will not incorporate these methodological assumptions into their assessment of the

project, we expect that the state will oppose the project though other means, making the project's odds of construction in the next ten years poor.

West Coast Gas Marketing Issues

- The most appropriate liquid market point determinations were made based on proximity to the terminal, and estimated the levelized costs of new facilities needed to move the regasified LNG to locations where these prices could be realized

LPG Marketing Assessment

- The cost of shipping propane and butane to Japan via long term charter or newbuild VLGC to be $1.71/barrel.
- PFC Energy's estimations of Chicago area LPG prices indicate a Chicago market premium of $1.50/barrel over Japan, and that this differential would be unchanged if the AGPA project went forward, but would decline to $1/barrel if the Chicago pipeline project went forward.

Cost Estimate Review

- PFC Energy's estimates of the AGPA project's costs were 5%-8% higher than the estimates generated by Bechtel, but for the purpose of determining project economics, the Bechtel costs were used.
- PFC Energy estimates the cost of shipping LNG via Jones Act-compliant tankers to be 54% above those of tankers not required to comply with the Jones Act, due primarily to higher construction costs and being subject to US taxes. PFC Energy believes that deliveries to Kitimat would also be subject to Jones Act requirements because
    - Canada in general and British Columbia in particular is already an exporter of natural gas to the United States, and some portion of this gas will ultimately be delivered to the United States
    - The natural gas will not be substantially processed or transformed in Canada; Kitimat's developers planned to extract LPGs from received LNG at the receiving terminal, but the AGPA project is not likely to produce multiple specifications of LNG for different terminals without incurring a thermal efficiency penalty in the liquefaction facility

Alaska Netback Comparison

- The netbacks were calculated based on levelized project cost estimates for the AGPA project and using an estimate for the Alaska-Chicago pipeline tariff provided by the Alaska Department of Revenue as well as PFC Energy's estimate of the average price realized by both projects:
    - $5.93/MMBtu for the AGPA project
    - $6.54/MMBtu for the Chicago pipeline project
- The AGPA project offers a significantly lower netback to North Slope gas than the Chicago pipeline project; PFC Energy estimates a netback to North Slope gas via the Chicago pipeline of $4.69/MMBtu, as opposed to $3.17/MMBtu for the AGPA project based on public domain asset cost estimates where available (i.e. AGPA for liquefaction facilities, LNG terminal project sponsors for

terminal costs, etc.). Using PFC Energy's internally generated asset cost estimates for the AGPA project, the difference widens, with the AGPA netback dropping to $3.05/MMBtu.

- The average price received by the AGPA project for gas sold into the West Coast is an average of $0.61/MMBtu lower than that realized by the Chicago pipeline project, due primarily to regional gas price differentials and the greater average distance of AGPA sales form major consuming centers relative to the Chicago pipeline project.
- The breakeven cost for the Chicago pipeline project to transport gas (net of LPG revenue) is $1.85/MMBtu. A levelized tariff of $2.76 would be needed for the AGPA project based on public domain costs, and $2.88 based on PFC Energy's asset cost estimates. Either way, the Chicago pipeline project has a decisive cost advantage.
- PFC Energy's assumption that the AGPA project will not be able to realize a premium for ethane in the rich gas stream has an adverse impact on this project's projected economics, but is not a decisive factor.

3. West Coast LNG Import Terminal Evaluation

Introduction

PFC Energy was asked to assess the likelihood of four specific LNG import terminal development projects successfully entering commercial service within the next ten years. A fifth was subsequently added, resulting in the project list below:

Kitimat LNG – Kitimat, British Columbia

Northern Star – Bradford, Oregon

Clearwater Port – Offshore from Oxnard, California

Port Penguin – Offshore from Pendleton, California

Sound Energy Solutions – Port of Long Beach, CA

There are many other West Coast LNG import terminal projects under development, but other projects were not included in the scope of analysis.

PFC Energy's analytical framework in this section is to look at four principal criteria, each of which can undermine a project's viability:

Likelihood of a Federal/Provincial Approval: The primary environmental review authority in Canada is the province, and in the United States it is the Federal government. For projects that have begun the permitting process, the progress to date has been considered, as well as the public record. For projects that have not yet started the permitting process, likely issues and past precedents in LNG terminal permitting are considered.

Likelihood of State/Local Permits: In addition to the main project permitting process looking at major environmental impacts, there is a plethora of other smaller permits that are essential for each project to succeed including coastal zone management, stormwater management, zoning and road construction, and others depending on local requirements. One of the main considerations here is local support/opposition. Though local support/opposition plays a role in the Federal/Provincial permitting process, the permitting delays and lawsuits that can result from organized and determined local opposition can pose a substantial obstacle to project development, while community support can be an invaluable asset.

Likelihood of Being the First Project In the Area To Be Ready for Financing: For most of the projects under consideration, there are other projects in development in close proximity. For each area (British Columbia, the Columbia River, Offshore Los Angeles), multiple projects will not be viable. In addition to the difficulties of placing such large volumes into these areas in competition with pipeline supplies, the economics of expanding existing sites are compelling enough to make additional project developments unlikely. Though multiple sites have been developed in close proximity on the US Gulf Coast, they are generally larger projects, and in an area with far higher gas transmission/offtake capabilities.

Index to terms used and the approximate likelihood represented	
Excellent	>95%
Likely	80%
Good	65%
Mediocre	50%
Fair	35%
Poor	20%
Negligible	<5%

Likelihood of Financing and Construction: For projects that are the first to be ready for financing and construction, this assesses the prospect of winning commercial financing, based on strength of local markets and market size. Major consideration is given to project location and ability to access higher value markets. The graph below shows historic differentials for several liquid gas market trading points relative to the PG&E city gate price near San Francisco, the highest value West Coast gas trading point, illustrating that the further north the trading point, the greater the discount to the highest value West Coast market.

3.1 Kitimat LNG - Kitimat, British Columbia

The proposed Kitimat LNG terminal site is close to the private port of Kitimat in British Columbia, close to other industrial facilities including an aluminum smelter and a currently disused methanol/ammonia production complex. The project enjoys considerable local support and is ahead of its main competing project in British Columbia in the permitting process. Its northern location is a disadvantage with respect to commerciality, however, because it is so far removed from large consuming centers.

The Kitimat project is well advanced in the provincial Environmental Assessment (EA) process. The project requested and received a temporary suspension of the 180-day provincial EA process in order to have time to provide additional information. Such delays are not uncommon, particularly in light of the aggressive 180 day schedule for the review. A review of the public record reveals no major flaws in the project, though not all of the record is in the public domain.

The project has apparently resolved aboriginal issues with the Haisla First Nation by changing the site's preferred location from Emsley Cove to Bish Cove (closer to Kitimat on the same waterway). The Haisla had consistently expressed a preference for the Bish Cove site, and once Kitimat LNG changed the preferred location to Bish Cove, the Haisla announced support of the project. An additional benefit to Kitimat LNG is an agreement with the Haisla that should the Bish Cove site not receive a permit despite Kitimat LNG's best efforts, the Haisla will support the Emsley Cove site.

The change in project location necessitated additional site evaluation at Bish Cove, some of which must wait fro spring as it relates to the evaluation of local flora and fauna. Assuming timely completion of the requisite studies and incorporation into EA filings, the provincial Environmental Assessment Office submitting may submit its report and recommendation in the second quarter of 2006, and PFC Energy's review of the project has not found anything that argues strongly against the project's success in winning approval.

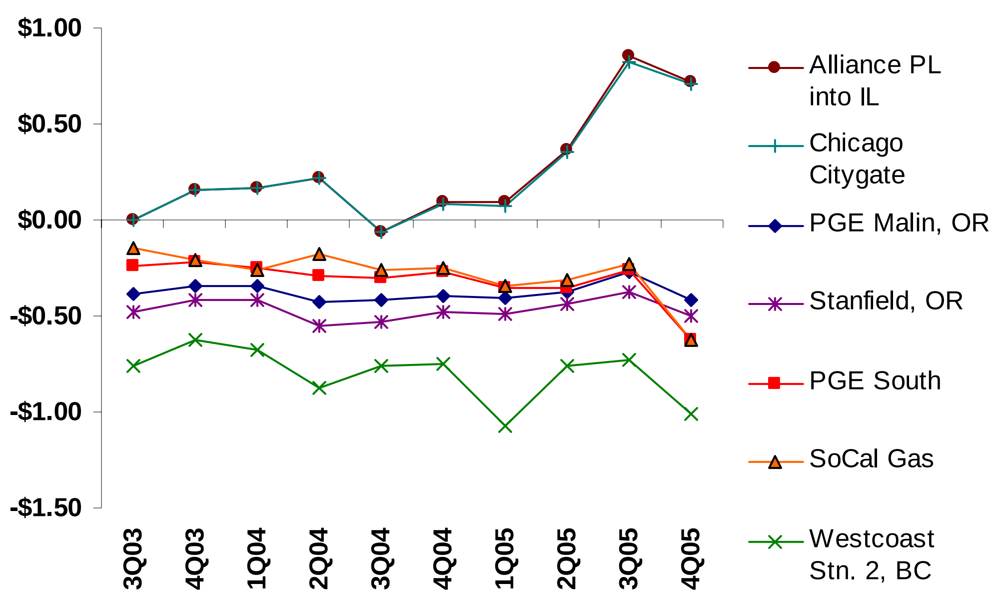
The local permits would likely be less difficult than the provincial authorization provided the project maintains good relations with the Haisla. The project's potential economic benefits are substantial and the area is home to numerous other industrial developments. Indeed, much of the local economy is driven by resource development and industry, making local communities more aware of and receptive to the benefits of industrial development.

The expansion of the Pacific Northern Gas (PNG) Pipeline from Kitimat to Westcoast pipeline station 4A at Summit Lake, BC will also require provincial and other regulatory approvals. The line's current capacity of 115 MMcfd is well below what is needed to service Kitimat LNG. PNG has assembled and posted on its website a description of its proposed Pipeline Looping Project which would add a 24 inch diameter high pressure pipeline to the existing system to provide adequate takeaway capacity for Kitimat LNG. Without this pipeline, the Kitimat LNG project would lack market access, and not be viable. PNG's project description summarizes the project, the main approvals needed and environmental and socio-economic impacts of the additional pipeline, as well as environmental mitigation measures including rerouting the additional pipe around environmentally sensitive areas currently traversed by the existing PNG pipeline right of way. Because most of the 500 km of new pipe is to be laid in existing rights of way, PNG is of the position that the project involves less than 75 km of new right of way and therefore does not require a comprehensive study of the project. Whether PNG prevails in this view or not, because there is an existing pipeline and right of way, PNG is likely to be successful in permitting its expanded transmission pipeline.

Kitimat LNG is well ahead of the WestPac Terminals project near Prince Rupert, British Columbia, and is likely to remain so as the project has not yet begun the EA process.

Though its remote location has facilitated the regulatory review process, its location works to the detriment of the project's economics. The local gas market is relatively small and readily supplied by gas production in British

Differential to PG&E City Gate Price For Different Gas Market Trading Locations
Prices in $/MMBtu



Columbia and Alberta along existing pipelines. Its location 1400 miles away from Los Angeles also means it is not well positioned to serve a high-value market, and if constructed, would likely function as a marginal supply source so long as LNG cargoes can be sold at a higher price through other import terminals.

The location of the Kitimat LNG project is such a disadvantage that were it the only site that could be permitted on the Canadian and US West Coasts (Mexico has already permitted a site), PFC Energy considers it likely that no import terminal would be constructed. The Rockies supply basins are closer to the premium markets of southern California, reducing the cost of incremental transmission pipelines, and ex-regasification supply economics are similar to the production economics of Rockies unconventional gas supply sources such as coalbed methane and tight sands, leaving the Rockies gas with a cost structure advantage. The West Coast gas price differentials graph illustrates this point, by showing the size of the discount of British Columbia Prices to those in Oregon or California. The closest gas market liquid trading point for the Kitimat project is Station 2 on the Westcoast pipeline, which saw average price discounts below the PG&E city gate of $1.25/MMBtu in 2004 and $1.46/MMBtu in the first half of 2005. Add in the cost of transporting regasified LNG from Kitimat to Westcoast station 2 (the current westbound firm tariff was C$0.50 per Gigajoule, and the netback to Kitimat is nearly $2/MMBtu below the PG&E citygate price, a substantial handicap for the Kitimat site.

It should be noted that the locational disadvantage would likely grow more severe with larger terminal capacities. Though the cost structure of the terminal would receive some benefit from economies of scale that would lower average costs, the market differential would suffer as the terminal displaces even more gas produced in British Columbia and has to access more distant markets to absorb a higher plant capacity. The Kitimat LNG terminal's initial phase of 610 MMcfd has been incorporated into the market analysis covered in Section 7 of this report, but the plant will be permitted for a capacity of 1,000 MMcfd. The project's sponsors have said the plant can be expanded to full permitted capacity as conditions warrant. PFC Energy modeled the project based on initial capacity so as to provide a conservative assessment of the project's economics on the assumption that higher volumes would have lowered the average revenue per Mcf received for Alaskan LNG sales based not only on the average prices as modeled, but also further depression of the British Columbia market price relative to Henry Hub.

Summary for Kitimat LNG – Kitimat, BC	
Likelihood of a Federal/Provincial Permit	Likely
Likelihood of State/Local Permits	Likely
Likelihood of Being the First Project In the Area (BC) To Be Ready for Financing	Excellent
Likelihood of Financing and Construction	Poor
Conclusion: Likelihood of Construction In the Next Ten Years	Poor

3.2 Northern Star – Bradford, Oregon

The Northern Star site is one of several proposed on the tidal Columbia River running between Washington and Oregon. The Northern Star site is zoned for marine industrial use and has been approved as a port site by the State of Oregon, but would require some dredging to facilitate LNG tankers. Its current planned initial capacity is 1 Bcfd, and the project is seeking permits for three 165,000 cubic meter LNG storage tanks, planning to build two for initial operation and complete the third if traffic warrants.

Northern Star is in the FERC pre-filing process, which is intended to give the public an opportunity to learn about the project and to facilitate communication between the project and various permitting bodies regarding the nature of the project and the documentation required for the FERC permitting process. The pre-filing process can ideally shorten the period required for consideration of the formal project application by raising and addressing potential problems early in the process, but this presupposes that amicable resolutions are possible.

Few major issues have been raised regarding the project's application beyond those raised by the Columbia River Inter-Tribal Fish Commission, whose central concern is the health of area fisheries and are concerned about the loss of fish habitat and also the potential for dredging to release buried toxic sediments into the water column where they can be ingested by local salmon and steelhead which, as a staple food, would pose a health risk to the Nez Perce and the Confederated Tribes of the Umatilla Indian Reservation. Both the Confederated Tribes of the Umatilla Indian Reservation and the Nez Perce, as sovereign governments, have requested government-to-government consultations on the matter. The Columbia River Inter-Tribal Fish Commission and The Nature Conservancy have raised the issue of the proposed project site's proximity to the Julia Butler Hansen and Lewis and Clark National Wildlife Refuges. Additionally, The Nature Conservancy owns and manages a nature preserve on the western shore of Puget Island in Washington which is approximately one kilometer northeast of the proposed project site across open water. Proximity to these areas opens the possibility for magnified wildlife impacts of both the terminal's construction and associated dredging. Analysis of the dredging and other wildlife impacts is still underway, however, complicating PFC Energy's assessment of their effect on the project's overall environmental impact and likelihood of permitting success.

One point in favor of the project is its decision on LNG vaporization. The project considered using river water to provide vaporization heat, but has since elected to construct a small electricity cogeneration plant and use its waste heat to provide vaporization heat. While this change may lengthen the pre-filing period as additional environmental impact analysis takes place, it is likely to remove larger complications associated with the impact on river water. Planned Gulf of Mexico LNG import terminal projects that have proposed to use open rack vaporizers (using Gulf waters to provide vaporization heat) have proven controversial given potential impacts of changes in water temperature on marine life. Given the existing concern regarding the impact of the project on Columbia River fisheries, avoiding use of the river water avoids what could have proven a troublesome issue.

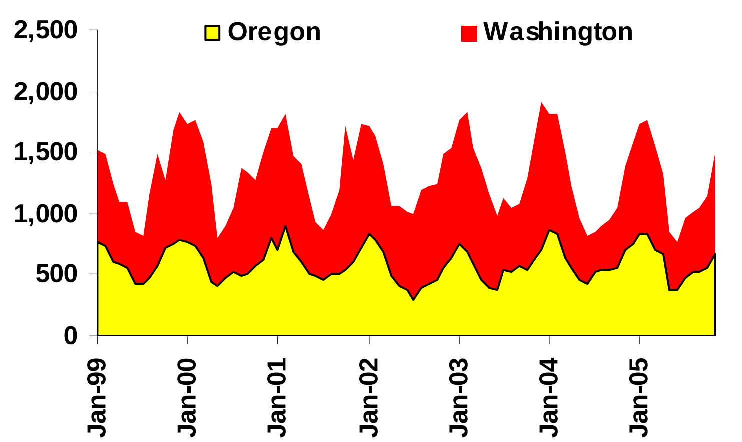
A review of the public record shows that some local issues have been raised which could need to be addressed. The land owned by the project sponsors has several different zoning designations in different areas, some of which would not be consistent with industrial use. The project does not propose to use the whole property, but there is also the question of applicability of local permitting given the Energy Policy Act of 2005's granting to FERC authority to supersede local zoning. To further complicate the issue, even if FERC can override local zoning decisions, those same zoning issues can be raised in determinations of whether the project complies with the state's Coastal Zone Management plan, which could have the effect of limiting FERC's ability to override local zoning.

Another potential issue relates to exclusion zones around the terminal and LNG tankers arriving and departing the terminal, and their potential impact on commercial and recreational users of the Columbia River and its shorelines. Commercial fishermen are concerned about not being able to fish or transit the river when LNG tankers are in transit or in port, affecting their livelihood. Recreational boaters are concerned about the potential loss of recreational opportunities. The Wahkiakum Port District #2 has expressed concern about how their 70 acre riverside recreational facility, the shores of which are less than 500 feet from the Columbia River navigation channel, would be affected by LNG tanker exclusion zones, not only for its boat ramp but also for onshore uses.

The ultimate impact of both of these issues on the process of creating the Environmental Impact Statement and on overall project approval is difficult to gauge because the analysis of dredging and exclusion zones are not yet complete. It is not uncommon for such issues to be raised, and the point of the pre-filing process is to raise such issues in order to facilitate their equitable resolution. Both issues have the potential to weigh against the project, but their ultimate impact depends on the analysis that is still underway. Some state and local issues have been addressed, however, such as relocating rather than abandoning a seldom-used rail line across the proposed project site.

The Northern Star terminal is the most advanced project with respect to the environmental assessment/regulatory process of all proposed Columbia River LNG import terminal projects. Other projects such as Skipanon LNG, Port Westward LNG and others have yet to begin the FERC prefiling process which Northern Star started in February 2005. Because this head start is a very significant but not insurmountable advantage relative to other projects, it is likely that should the project receive FERC and other approvals and permits, it would be the first Columbia River LNG import terminal to be ready for financing.

Monthly Gas Consumption in Oregon and Washington
Million cubic feet per day



The likelihood of financing and construction of the Northern Star LNG import terminal is poor due to several factors stemming from location. Its location away from main consumption centers means that the price received is lowered by the cost of transporting gas to California demand centers, and that the regasified LNG will be in direct competition with Alberta and Rockies gas supplies for existing gas transmission pipeline capacity and market share.

The project would have substantial throughput risk on both a seasonal and long-term basis. The seasonal risk would come from the highly seasonal nature of gas demand in Washington and Oregon, where gas consumption routinely falls to or below 1 Bcfd in the late spring/early summer. Additionally, given the heavy reliance of the northwest on hydropower, variations in rainfall will drive fluctuations in gas demand from power generation. In a dry year, gas will be in higher demand for power generation, but in a wet year with high hydro power production, gas-fired generation will be marginalized. This serves to highlight the project's dependence on the California market; even if the project could have 100% market share in its closest markets, it could not operate at capacity for 12 months per year without accessing the California market. The long-term throughput risk stems from alternate gas supplies, including growing Rockies gas output and other West Coast outlets for Alaskan LNG. California LNG terminals will have an advantage over Columbia River terminals given their proximity to major consuming centers. In the long term, the economics of supply into California from the Rockies or California LNG terminals may prove to be lower cost options than supply from Northern Star, pushing the terminal into a seasonal or marginal supply role. It should be noted that even the presence of long term supply and offtake contracts is not a guarantee of throughput, as the experience of US LNG in the 1970s and 1980s demonstrated – if some LNG supply sources are no longer competitive, such obligations can be renegotiated or abrogated, and in extreme circumstances, annulled by bankruptcy proceedings.

Summary for Northern Star – Bradford, OR	
Likelihood of a Federal/Provincial Permit	Good
Likelihood of State/Local Permits	Good
Likelihood of Being the First Project In the Area (WA/OR) To Be Ready for Financing	Likely
Likelihood of Financing and Construction	Poor
Conclusion: Likelihood of Construction In the Next Ten Years	Poor

3.3 Clearwater Port – Offshore Oxnard, California

Crystal Energy has proposed to convert an existing offshore oil production platform in water over 300 feet deep roughly thirteen miles offshore from Oxnard, California into a facility to import and regasify LNG called Clearwater Port. The platform no longer actively produces oil, but does remain in service to support another nearby platform. The port would regasify LNG and then send the gas ashore through a new gas pipeline following the same right of way as the existing oil production pipelines that were constructed to service the platforms, but unlike other projects, it would not have LNG storage capacity. By using existing infrastructure and accessing the Los Angeles area market directly, the project aims to have cost advantage and to enter service faster than competing projects while having less environmental impact.

The project was announced in March 2003, and in early January 2004 submitted its application for a deepwater port license. In late January 2004 signed a Memorandum of Understanding with the Alaska Gasline Port Authority to supply up to 800 million cubic feet of gas per day, the first nonbinding step in negotiating an LNG supply agreement. In October 2004 Crystal Energy signed an agreement in principle with Woodside Energy for technical assistance in developing the terminal, to provide funding to Crystal for the permitting and approvals processes undertaken by the project, and to grant Woodside preferential access to most of the project's 800 million cubic foot per day capacity. Following the expiration of this agreement with Woodside, Crystal announced in late June 2005 that it was redefining its relationship with Woodside to include non-exclusive discussions for LNG supply, but that Woodside would still have preferential access to a portion of the terminal's capacity. In January 2006, Woodside announced that it plans to develop its own assets for importing LNG into southern California.

The US Maritime Administration, who oversees the deepwater port licensing process, returned Crystal Energy's application as incomplete, and has not yet received an application it has determined to be complete. This complicates the issue of determining the likelihood of a deepwater port license, as there is no public domain record to study. As two years have passed since the application's initial submission, however, it is clear that the process is not progressing in a timely manner, raising the question of whether the company is receiving adequate resources from its backers to complete the deepwater port license application (with associated environmental studies). The experience of Cabrillo port, also located offshore from Oxnard, California northwest of Clearwater's proposed location, shows that the process of permitting offshore California is particularly difficult. Cabrillo's sponsors filed a deepwater port application September 3, 2003, and it was found to be incomplete, but additional materials were submitted and it was found to be complete on January 27, 2004. The application process has a statutory 365 day timeframe, but this timeframe was suspended in April 2004 to allow time for additional materials to be submitted, and restarted on September 3, 2004. The Draft Environmental Impact Statement was released in October 2004 and, based on comments received, the statutory timeline was again halted January 5, 2005 as additional information regarding the project's description, public safety, maritime traffic, Air Quality, Terrestrial and Marine biology, geology noise and water quality, and has not resumed as of 3/17/2006.

The level of scrutiny afforded both the Clearwater and Cabrillo deepwater port applications is exceptional due not only to the diligence of federal authorities, but also to the high environmental standards of state and local authorities in California and the large number of nearby residents who have taken the opportunity to participate in the environmental review process. The result is the need for the highest quality of environmental impact analysis possible and the resources to see though a lengthy environmental review process.

Given the limited recent progress of Clearwater Port's deepwater port application and attendant environmental review and the regulatory challenges to such a project demonstrated by the experience of Cabrillo Port, PFC Energy assesses the likelihood of Clearwater receiving its deepwater port license as mediocre at best. The likelihood would be lower if not for the possibility of the project receiving additional external support at a later date.

Regarding state and local permits, the prospects are at best fair. The city of Oxnard has repeatedly stated its opposition to both the Clearwater and Cabrillo projects, and because part of the pipelines that will deliver the projects' gas to the California pipeline grid run in part through the City of Oxnard, it is in a position to substantially complicate the process of local permits and approvals. In addition, popular sentiment as indicated by the deepwater port application/environmental assessment public record is overwhelmingly negative. Such broad opposition represents an additional hurdle in obtaining necessary state and local permits.

The Clearwater Port project likelihood of being the first California project ready for financing is poor, as it is running well behind the Cabrillo Port proposal in the deepwater port licensing process. The Sound Energy Solutions plant in the Port of Long Beach is also further advanced with its application to the Federal Energy Regulatory Commission for its onshore terminal proposal.

The likelihood of financing and construction of the Clearwater Port project is poor. The lack of any apparent recent progress submitting materials in support of its deepwater port application, the substantial progress of a nearby, directly competing project and the questionable need for two very similar projects puts Clearwater Port at a clear disadvantage. Additionally, because of the similarities of the two projects, a permitting/environmental analysis failure of Cabrillo Port is unlikely to improve the prospects of Clearwater Port as Clearwater would likely have any of the same deficiencies found in the Cabrillo proposal. Furthermore, it is unlikely that the Southern California Gas transmission system could absorb the supply of both projects without substantial investment, triggering an expanded environmental review that could severely disadvantage the second project. These factors together make it difficult to imagine a circumstance in which the Clearwater Port project is completed.

Summary for Clearwater Port – Offshore Oxnard, CA	
Likelihood of a Federal/Provincial Permit	Mediocre
Likelihood of State/Local Permits	Fair
Likelihood of Being the First Project In the Area (CA) To Be Ready for Financing	Poor
Likelihood of Financing and Construction	Poor
Conclusion: Likelihood of Construction In the Next Ten Years	Poor

3.4 Port Penguin – Offshore Pendleton, California

ChevronTexaco proposed an offshore LNG terminal off California, the project development effort apparently did not make substantial progress and now appears abandoned. No applications have been filed, the project does not appear on ChevronTexaco's website and the California Energy Commission's listings of LNG projects indicate that the project is no longer under development. It is possible that ChevronTexaco's development focus shifted to the Terminal GNL Mar Adentro De Baja California project near the Coronado Islands off the Mexican coast near the California border. This, too, is an offshore terminal concept, a gravity base structure similar to that approved for Port Pelican in the US Gulf of Mexico and reportedly considered for Port Penguin.

Given the apparent absence of a project development effort, it is difficult to apply a meaningful likelihood of success. It is safe to say, however, that without effort, the odds of success in obtaining a deepwater port license are negligible. The same can be said of state and local permits and authorizations, the likelihood of being the first terminal ready for financing and the likelihood of the project being constructed.

Summary for Port Penguin – Offshore CA	
Likelihood of a Federal/Provincial Permit	Negligible
Likelihood of State/Local Permits	Negligible
Likelihood of Being the First Project In the Area (CA) To Be Ready for Financing	Negligible
Likelihood of Financing and Construction	Negligible
Conclusion: Likelihood of Construction In the Next Ten Years	Negligible

3.5 Sound Energy Solutions – Port of Long Beach, California

Sound Energy Solutions (SES) has proposed a LNG import and regasification terminal for the Port of Long Beach on a brownfield site. While this proposal has the advantage of reusing a site already used for marine industry purposes, the Port of Long Beach is one of the United States' busiest ports, raising concerns regarding effect on other commercial marine traffic and potential cascade effects in the event of a serious accident. The project will include gas processing facilities to remove any excess LPGs from the LNG in order to meet US gas specifications for energy density, an ethane pipeline to a nearby refinery and also include a facility for loading LNG truck tanks to facilitate the delivery of LNG as a vehicle fuel.

The project is well advanced in FERC's project evaluation process, and a Draft Environmental Impact Statement/Draft Environmental Impact Report (DEIS) was released for public comment in October 2005. SES remains actively engaged with permitting bodies.

Absent from the DEIS were comments relating to the Coast Guard's Waterway Suitability Analysis (WSA), which is required for final approval. On page 4-164 of the DEIS, FERC states that issuance of preliminary and follow-on WSA are prerequisites to the issuance of a final Environmental Impact Statement (EIS). The WSA will be important as it addresses one of the principal issues of the project, namely the suitability of the Port of Long Beach as the site for and LNG terminal given the potential impact on commercial vessel traffic from moving exclusion zones around LNG tankers, and risk to maritime operations in general. Another issue in the WSA is the Coast Guard's evaluation of planned maritime security measures. Division of security costs between state and local authorities and LNG terminal developers can be a contentious issue, and if this has not yet been resolved, it would hold up the final maritime security plan and the WSA, which is meant to evaluate the final maritime security plan. Indeed, the California Energy Commission has contended that because the DEIS does not include WSA input, the DEIS is incomplete and flawed.

PFC Energy's analysis of the FERC record for the SES project (docket CP04-58) indicates substantial differences between the FERC and the State of California on the standards to apply in assessing the risks of LNG vessels and facilities. The California Energy Commission and the California State Lands Commission had similar but not identical comments on the DEIS; for the purpose of this discussion, both will be referred to jointly as the State of California (SoC). It should also be noted that comments filed by the City of Long Beach included some of the same points as those raised by the SoC. A partial list of potentially important differences includes:

- The FERC uses a radiant heat exposure of 1600 Btu/square foot to establish the threshold of acceptable exposure for unprotected people. The SoC notes that at that exposure level blistering of the skin can occur in less than one minute, and contends that a more appropriate standard is one at which long-term exposure can be sustained with no measurable adverse health effect. The SoC nominates an exposure threshold of 450 Btu/square foot as the appropriate level for the purpose of risk estimation. If this level were used, the need for exclusion zones and the estimated impact of igniting vapour clouds, accidents and facility fires would grow accordingly. The SoC also contends that lower thresholds for structures outside of the facility boundary should apply in establishing exclusions zones (800 Btu/square foot as opposed to the 3000 Btu/square foot used in the DEIS).
- The FERC does not agree with analyzing worst-case, high-consequence, low-probability events without accounting for the beneficial effects of preventative or mitigation measures as part of a risk management process. The SoC, however, has asserted that a full range of potential releases and their probabilities should be assessed, including cascade accidents, terrorist takeovers of LNG tankers and natural disasters such as an earthquake or a tsunami.
- The SoC has disagreed with some of the DEIS work on assessing the risk from flammable clouds resulting from accidental LNG releases, including disputing the assumption (made by the risk assessment consultant to SES) that large flammable clouds will not travel long distances because of ignition sources along the way; the SoC contends that this assumption is unsupported and that in its absence, the risks of drifting flammable releases traveling substantially greater distances before ignition place a much larger geographical area at risk than depicted in the DEIS.

Each of these factors individually could significantly increase the estimate of risks associated with the SES Long Beach LNG terminal. In combination, they would result in a very significant increase in assessed risks from the project (i.e. lower thermal exposure thresholds from larger potential releases drifting greater distances suggests far larger exclusion zones that can be accommodated in Long Beach).

The U.S. Energy Policy Act of 2005 included a provision granting FERC exclusive authority over the project permitting process for onshore LNG terminals, but requires consultation with state and local authorities, and leaves several processes (such as coastal zone management) in state hands. The legislation does not specify the form of the consultation, and as such, there is almost no precedent to guide how much input the state is granted into the permitting process. With California specifying its objections in the FERC project evaluation record, the state may pursue challenges to the project should the final EIS resolve the outstanding issues to the satisfaction of federal standards and the FERC grant the project approval to proceed. Such challenges could cause project delays of indeterminate length.

It should also be noted that because the Coast Guard's WSA may pose a challenge to the issuance of a final Environmental Impact Statement. The WSA is meant to assess, among other things, the suitability of security arrangements for transiting LNG tankers and unloading operations. The security arrangements will not be finalized until SES and state and local authorities agree on a proposed security plan and a cost sharing agreement to fund the plan. If some of these state and local authorities consider the project's risks to be substantially higher than has been assessed in the DEIS (as indicated in the points above) they may be interested in a higher level of security than the terminal sponsors, and be less willing to share the costs, making it much more difficult to achieve agreement on a marine security plan. Failing to agree on a marine security plan with financing could therefore stall the WSA and the issuance of a final environmental impact statement. Even with agreement on financing and security arrangements, a favorable WSA is not assured, but given the port's already substantial hydrocarbon traffic, many of the requisite security provisions may already be in place.

One of the key issues in assessing the likelihood of the construction of the Long Beach terminal in the next ten years is the extent to which California can assert its own standards on the project. Applying California's standards (rather than those applied by FERC) would dramatically reduce the likelihood of the project winning approval given the increased assessment of risk to areas near the terminal, though until such time as the assessments are undertaken, it is not possible to quantify the risk.

PFC Energy considers it likely that FERC will maintain the risk assessment standards used in the DEIS rather than incorporate the SoC's standards. Given the risk assessments in the DEIS, the project can be approved subject to the resolution of some issues such as cost sharing agreements for plant and marine security and backing up the assumption that LNG vapor clouds will not drift long distances. A recommendation to approve the project in the final environmental impact assessment is not assured but, given the assessments to date, is possible. Given the uncertainties, PFC Energy considers the likelihood of the FERC review process to result in a recommendation to approve the project as good. It should be noted that the prospect of challenges to such a ruling are not factored into this rating, but are included in the Likelihood of Construction in the Next Ten Years assessment below.

PFC Energy expects the project to face considerably more difficulty in securing requisite state and local approvals. SoC comments on the DEIS indicate that they see the project as posing more risks to the vicinity of the terminal site than federal authorities. The California Energy Commission, the California State Lands Commission and the City of Long Beach expressed similar concerns about the project, and in the absence of their concerns being addressed in a way that still indicates negligible risk to life, state and at least some local government support will be lacking. In addition, many residents of adjacent areas have expressed opposition to the project, though others have expressed support. Though the requisite state and local permits and approvals may not bear directly upon the issues raised by the SoC to the DEIS, the odds of securing those approvals are adversely affected by them. Should the project sponsors choose to challenge any adverse results, the time required may suit the interests of the SoC if the SoC is opposed to the project. Accordingly, PFC Energy considers the likelihood of State and Local approvals to be poor.

As discussed in the assessment of Clearwater Port, the Cabrillo Port project is well advanced in the project assessment portion of its application for a deepwater port license, having released its DEIS for public comment in November 2004. Cabrillo Port is approximately 60 miles west by northwest from the Port of Long Beach, so the two could be seen as competing projects, but California consumes more natural gas than the combined capacity of the two projects, and it appears that the existing Southern California Gas transmission and distribution system can absorb both projects without substantial new investment. The SES project has already reduced its planned sustained operating capacity from 1,000 MMcfd to 700 MMcfd because of the capacity of Southern California Gas's current facilities to absorb the project's output. Southern California Gas's facilities could be expanded, but the environmental impact of this expansion activity would have to be measured and weighed as part of the terminal project's environmental assessment as an impact directly attributable to the project. Cabrillo and SES are on different segments of Southern California Gas's trunkline system, so the two do not appear to compete for existing capacity in the same way Cabrillo and Clearwater do.

Given the absence of projects that would pre-empt the market opportunity for the SES terminal, PFC Energy considers the prospect of the SES terminal being the first to be ready for financing/construction to be excellent. While PFC Energy used larger areas for the evaluation of other terminals (British Columbia for Kitimat, Washington and Oregon for Northern Star) both of those areas were dependent on external demand for part or all of the project's year-round output. For these projects feeding directly into the Southern California Gas system, they are tapping into a much larger market, and so there is room for both.

In the event of receiving all regulatory approvals, PFC Energy expects the project sponsors would have no qualms financing the project internally if debt financing could not be secured. The project sponsors have substantial resources and can proceed without external finance.

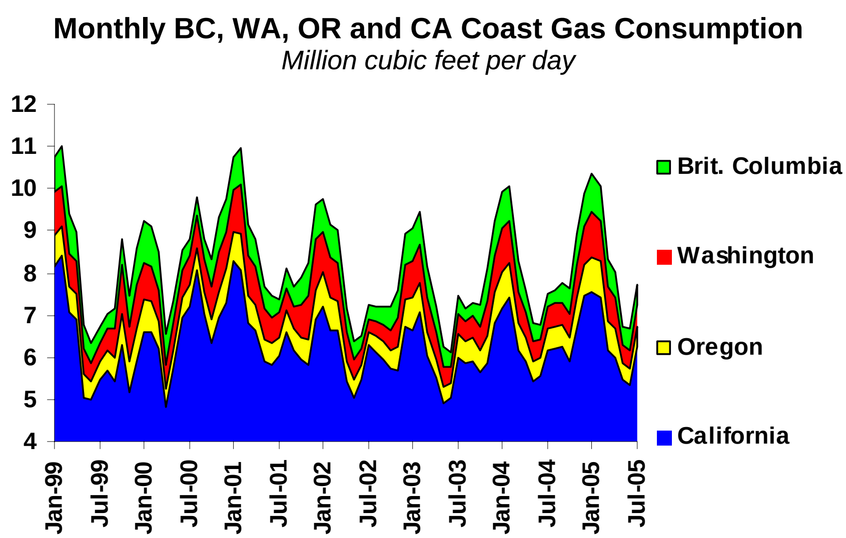
PFC Energy's determination of the likelihood of financing and construction in the next ten years is heavily influenced by the objections to the DEIS raised by the California Energy Commission, the California State Lands Commission and the City of Long Beach. Given the objections raised, it is extremely difficult for the project to be viewed as having acceptable risks to the area when applying SoC criteria. In keeping with this assessment, the State of California and perhaps other local government bodies would be expected to oppose the project where it can do so while staying consistent with relevant regulations and procedures for approvals. This may well extend to challenges to the project in court. The state's objections to the DEIS could be appealed through the courts if the project is recommended for approval to FERC. Additionally, individuals and nongovernmental organizations could also oppose the project. The project's site inside the perimeter of the Port of Long Beach reduces the likelihood of on-site protests, but this was not the primary threat to the project. Delays in negotiating security and cost sharing agreements with local government as well as delays and opposition in Coastal Zone Management approvals are examples of the challenges the project may continue to face. Because the project sponsors'

Summary for SES – Port of Long Beach, CA	
Likelihood of a Federal/Provincial Permit	Good
Likelihood of State/Local Permits	Poor
Likelihood of Being the First Project In the Area (CA) To Be Ready for Financing	Excellent
Likelihood of Financing and Construction if approval granted	Likely
Conclusion: Likelihood of Construction In the Next Ten Years	Poor

resources are substantial but not infinite, PFC Energy regards the odds of financing and construction of the terminal in the next ten years to be poor.

Conclusion

Many more LNG import terminal proposals have been advanced than can succeed, and the West Coast is no exception. While it is true that North America needs substantial and geographically diversified LNG import capacity, the comparatively modest size of the West Coast market and its proximity to steady West Canadian and rising Rockies gas production mean that its need for LNG import capacity is modest, and it would be difficult for the West Coast (even including Mexico) to import 3.3 Bcfd of regasified LNG given the volume of US and Canadian produced gas that would have to be displaced into East of Rockies gas markets and the sunk costs in pipeline infrastructure that would no longer be needed. On the Gulf Coast, terminals can replace declining production volumes and use existing infrastructure, while East Coast terminals can more directly access high value markets that are well removed from major gas production areas. Indeed, given the market, it will be difficult to support any four large West Coast LNG import terminals, and it is highly unlikely that four of the five the specific terminals discussed above will be constructed.



4. West Coast Gas Marketing Issues

4.1 Liquid Market Points for Each Terminal

For each LNG receiving terminal, PFC Energy ascertained the most appropriate liquid market point based on proximity to the terminal. For a graphical representation of these liquid market points relative to the terminal sites, please refer to the map in section 7.2.

Terminal	Liquid Market Point
Kitimat, British Columbia	Westcoast Station 2, British Columbia
Northern Star, Oregon	Stanfield, Oregon
Clearwater Port, Offshore California	SoCal Gas, Southern California
Port Penguin, Offshore California	SoCal Gas, Southern California

4.2 Cost of Moving Regasified LNG to Liquid Market Points

The Asia-Pacific LNG market's progression toward a phase of broader growth provides importers with some new gas market dynamics and emerging market demand growth potential. As a result, supply/demand fundamentals of this increasingly diversified market begin to play a larger role in future price movements and contracting methods in the basin. With less mature gas markets expected to provide a larger call on LNG in the basin (i.e. China, India and the West Coast of the U.S./Mexico), the uncertainty of the level of future demand for LNG increases. Also, as new buyers have begun to seek more innovative contracting terms than has historically been the case in this basin, the price link between LNG and oil markets could become less connected.

Note: Northern Star and Kitimat gas price assumptions take into account tariff charge estimations to deliver gas from regasification facility tailgate to the liquid market point. Assumed that Port Penguin and Clearwater Port terminal have minimal cost related to accessing the SoCal gas system. Estimates include new pipeline costs to link to major pipeline system.

The various terminals have laid out plans for investments to link the terminals to the main pipeline networks. We have estimated costs for these links and believe that they are accounted for in the costs for the terminal.

There are however some additional costs for transporting gas from the entry point of the main pipeline to the market liquidity points. We summarize these costs/unit costs in the table below.

Terminal	Comment	Estimated cost $ million	$/MMBtu Equivalent
Kitimat	500 km of 24" 1440 psig pipe between summit Lake and Kitimat	$96	$0.12
Northern star	Reported Tariff	N/A	$0.31
Clearwater Port	Assumed minimal costs as close to market	N/A	N/A
Port Penguin	As above. Project is not defined in terms of location	N/A	N/A

5. LPG Marketing Assessment

5.1 LPG Marine Transportation Costs to Asia

The rising cost of steel and high demand on shipyards have made new LPG tankers of all sizes more expensive in the last several years, just as it has made new LNG, crude oil and refined product tankers more expensive. Additionally, shipyards have been stretched by rising vessel demand, also contributing to higher newbuild costs. For the purposes of this assessment, PFC Energy has assumed the lowest cost option for transporting LPG to Asia, a Very Large Gas Carrier (VLGC) with a cargo capacity of 78,000 cubic meters. Larger ships realize greater economies of scale, reducing shipping costs per unit of cargo, and have been the trend in LNG ships as well. It has been estimated that the newbuild cost of a 78,000 cubic meter VLGC has risen from $58 million in 2002 to $89-91 million today. This LPG shipping cost estimation is based on current vessel costs.

PFC Energy has assessed costs in three categories:

- Capital Costs, which reflect the cost of the ship
- Operating Costs, which reflect the costs of crewing and maintaining the vessel in seaworthy operating condition
- Voyage Costs, which reflect the variable costs of operating the vessel such as fuel and port fees

A review of recent vessel construction contracts indicates that the price for a new 78,000 cubic meter capacity VLGC from a Korean shipyard is approximately $90 million, which is consistent with a reported long term bareboat charter[1] price of $23,000 per day. These values have been used as the estimates of capital costs.

Operating costs have been assessed at approximately $4,900 per day. This estimate is subject to a relatively wide range of error given the number of options regarding the costs of crews with different levels of experience and qualifications, along with maintenance spending assumptions.

Voyage costs are estimated at $16,100 per day based on oil prices in the first half of 2005. PFC Energy elected to use the first half rather than the second half because the oil market impact of the US Gulf Coast hurricanes was exceptional, and not a suitable basis for projections.

Combined, this yields a daily operating cost for a vessel in active use (as opposed to resting at moorings waiting for charter) of $44,000 per day or $16.1 million per year. Combined with calculated sailing distances, an assumed sailing speed of 15.7 knots and a total allowance of 2.5 days for loading and unloading, PFC has calculated the shipping cost estimates in the table below.

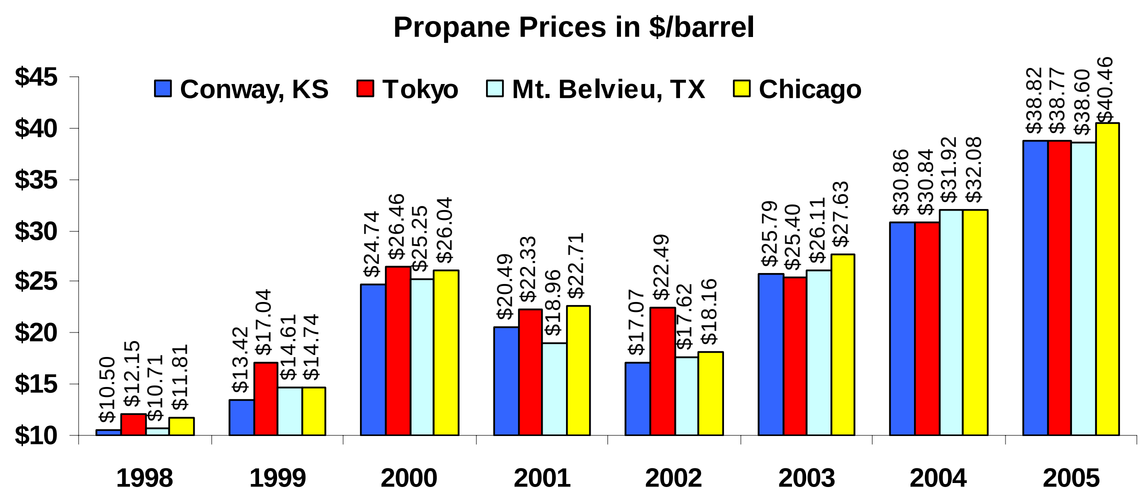
[1] *Similar to a vessel lease*

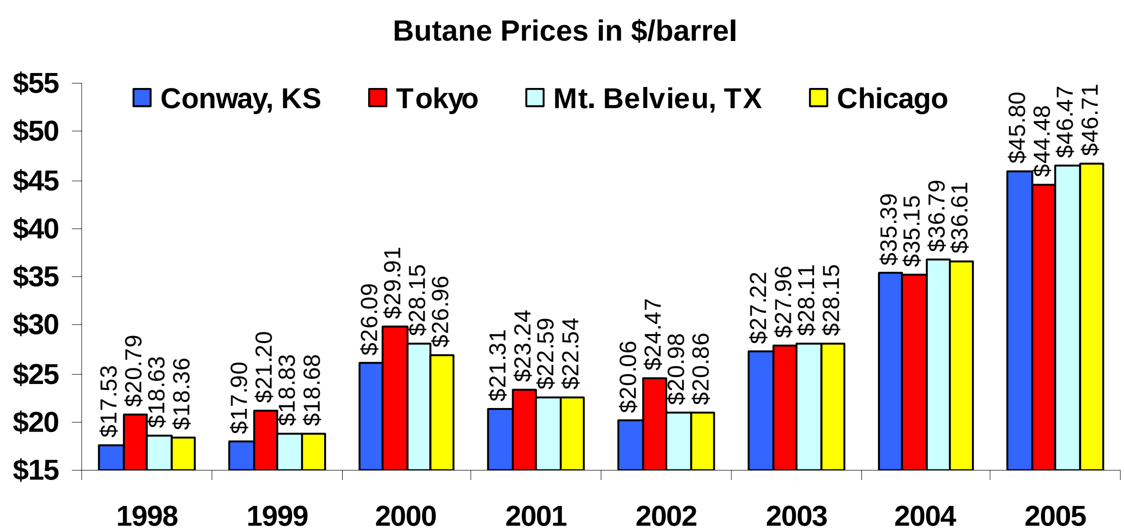
Estimated costs for long-term charter and resulting cost per gallon transported						
		One-way sailing time				
	Nautical Miles	Days	Hours	Voyage Days *	Voyage Cost	Voyage Cost/gallon
Yokohama	3,320	8	7	19.1	$839,667	$0.041

** Including allowances for loading and unloading time*

5.2 LPG Price Relationships

In the beginning of this decade, Tokyo propane prices were at a frequent premium to those in the United States Mid-continent, but the change in US gas market fundamentals that has accompanied supply constraints has also altered gas processing economics and LPG supply demand balances. The net result is that Tokyo propane prices are typically on par with those in Conway, Kansas (the closest major market center to Chicago). Furthermore, Chicago prices are at a premium to Conway, leaving Chicago at a modest premium to Tokyo, as





illustrated by the graph below.

Declining production in the mature oil and gas producing basins of the Gulf Coast as well as Western Canada are reducing locally-produced LPG volumes. Gulf Coast production is declining as well as mature onshore and shallow water offshore declines exceed increases from deepwater production and LPGs extracted from imported liquefied natural gas.

The northern Mid-continent area, including Chicago, is linked to both the Gulf Coast and Canada by pipelines which allow LPGs to be imported. The TEPPCO oil product pipeline that also carries LPGs from the Gulf Coast runs north from Texas to southern Illinois and Indiana and then east to the Philadelphia area, creating a linkage for LPGs from the mid-continent to the East Coast. Furthermore, LPGs can move from Alberta to the Mid-continent two ways: via oil products pipeline or via the Alliance "wet gas" pipeline (which transports partially processed gas which includes much more ethane, propane and butane than would be allowable in a normal pipeline). Both options create an LPG market linkage from Alberta to the northern mid-continent and, in the case of the Alliance pipeline, to the Chicago area where the line's southern terminus is located.

As a result of these low-cost transportation options, oil markets in most of the United States and western Canada are closely interlinked. The primary significance of this is that a change in supply or demand can be absorbed more readily than if they were each isolated systems because there are more options for supply and demand to re-equilibrate quickly and efficiently. In the case of the startup of the Alliance pipeline in 2000, which introduced a new supply of LPGs to the Chicago area, the result was to reduce the mid-continent's imports of LPGs from the Gulf Coast and Alberta.

The chart below shows that Mid-continent[2] propane demand has demonstrated a rising trend over the last eight years. While Mid-continent supplies from natural gas processing plants and refineries have been steady, net receipts from other parts of the United States and imports from Canada have risen to meet demand. From 1997 to 1999, net imports and net receipts of propane averaged 107 kb/d, but they averaged 138 kb/d from 2002 to 2004. Indeed, this understates the increase in propane transfers into the Mid-continent because it excludes propane receipts from Alberta via the Alliance pipeline, which are counted with other gas processors in the field production category.

The introduction of LPGs from an Alaskan natural gas pipeline to the Chicago area would transform the Mid-continent from a substantial net importing region to one that is a modest net importer. In 2004, net imports and net receipts (from the Gulf Coast) averaged 135 kb/d. The Alaskan gas pipeline project would bring roughly 50 kb/d of propane into the northern Mid-continent in the second year of operation and an average of over 67 kb/d in years 6-10 of operation, with volumes remaining near this level through the 30th year of operation. The butane

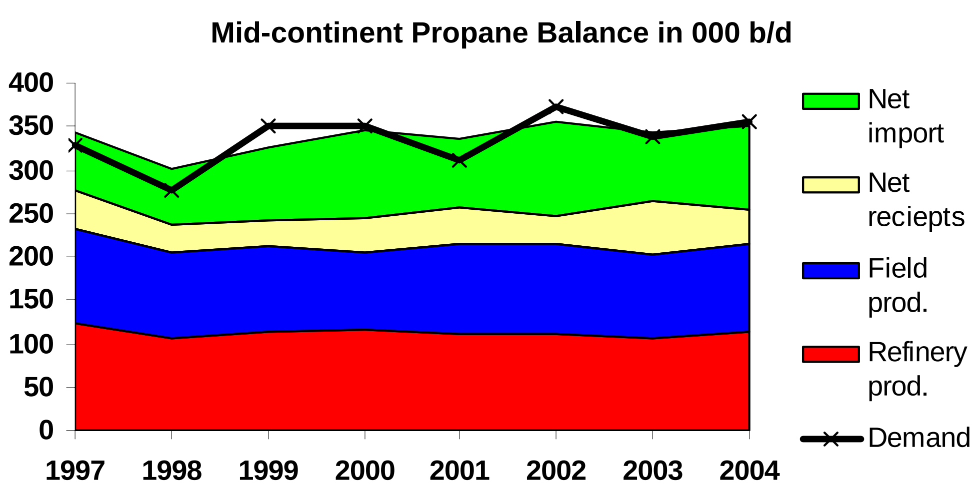
[2] *Defined here as the Energy Information Administration's PAD 2*

volumes would be 13 kb/d in the second year of operation, average 17 kb/d in years 6-10, and rise further to peak in the 30th year of operation.

The introduction of such large LPG volumes would change the flow of LPGs to and through the Mid-continent. 40 kb/d of propane were shipped from the Gulf Coast to the Mid-continent, and another 68 kb/d transited the Mid-continent en route to the East Coast. If the Alaskan LPGs could be used to replace the Gulf Coast supplies for both the Mid-continent and supplement supplies for the East Coast, the full volume would be marketed, but due to pipeline logistics, this is unlikely. It would require a pipeline from the Chicago area terminus of the Alaskan gas pipeline to the TEPPCO pipeline in southern Indiana of approximately 225 miles. Compared to building a pipeline from Alaska, this is a very modest distance along an existing pipeline right-of-way. It may also be possible to reorient some of the existing Mid-continent LPG-capable pipelines to carry Conway production south toward the Gulf Coast and reduce Gulf Coast imports. The alternative is for the Mid-continent to reduce both net receipts from the Gulf Coast and imports from Canada.

The linkages with other markets will clearly mitigate the price impact of the increase in Mid-continent LPG supplies from an Alaska gas pipeline. PFC Energy estimates it would lead to a decline in Chicago-area prices of roughly $1/b for propane and a similar amount for butane relative to where prices would have been without the additional supplies. The level of price adjustment required to back out current alternate supplies from outside of the Mid-continent is relatively modest because of the number of physical market linkages discussed above. Nevertheless, $1/b is not trivial, particularly when viewed in the context of the lower price levels that prevailed before 2003, when $1/b was 5% or more of the average Chicago price.

If the Alaskan LNG project goes forward, the volume of LPGs it adds to the Asian market should have no impact on propane and butane prices or differentials. As a much larger market that is heavily reliant on imports from the Arab Gulf, Alaskan LPGs will not become the marginal supply source and therefore have minimal impact on



regional prices.

From 2003 to 2005, the average premium of Chicago prices over Tokyo prices has been $1.50/b for both propane and butane. Given the above analysis, the premium is expected to decline to $0.50/b in the event that an Alaska-Chicago gas pipeline brings substantial new LPG volumes to the Chicago area. In the event of the AGPA's LNG project proceeding, the Chicago area LPG premium to Japan would remain $1.50/b.

6. Cost Estimate Review

The complex nature of the proposed Alaska LNG project and the multitude of pieces required to make the project work bring a great deal of uncertainty regarding the financial viability of the project. There is significant risk related to the costs of the facilities being built and the timing of project start-up due to the large scale of construction required. In this section, PFC Energy estimates the break even costs of each segment of the project, for both the infrastructure funded by AGPA and outside parties (i.e. Gas Conditioning Plant and regasification facilities). The costs related to these different segments have been estimated using two methods – PFC Energy's internal estimates based upon a bottom-up costing approach, and capital estimates available in the public domain (partially from AGPA's published costs from Bechtel). In estimating the break even costs of each segment of this project, PFC Energy has used the publicly available costs, but parallel PFC Energy cost estimates were generated in order to provide potential cost risks. As will be shown in following sections, however, the PFC Energy cost estimates are typically higher than public domain estimates. The range of costs however do not change the conclusions derived from the economic modeling. In fact, the PFC Energy estimates make the economics of the AGPA proposed project look slightly worse.

6.1 Jones Act Implications for the AGPA Project

The Jones Act was passed by Congress in 1920 to protect the US domestic shipping industry. It essentially requires vessels engaged in U.S. domestic shipping to be:

- U.S. built
- U.S. flagged
- U.S. owned and operated
- Or, if rebuilt abroad, not be more than 500 tons
- Are subject to US laws, taxes, regulations - i.e. labor laws, minimum wage, tax liabilities, health and safety protections, and environmental standards

Of course U.S. shipyards are not yet at a point at which they can build very large, self-propelled vessels at prices that equal some foreign shipyards. Various prior studies have suggested that these US vessels would cost some 30% -300% more than an equivalent foreign built vessel. In addition there have been claims that a reduced level of competition for vessels from fewer US yards would result in higher prices. Over time one would expect U.S. shipyards to make progress in closing the cost gap with foreign shipyards on these vessels, but it will take time and practice. Foreign shipyards have spent years perfecting their building techniques and with the aid of government subsidized construction contracts.

Several U.S. laws exist apart from the Jones Act, including environmental, labor and tax laws. These themselves may significantly increase the costs of vessels operating in U.S. waters. Additionally, open-ended spill liabilities (which places no limit on the amount for which a party can sue a vessel owner) for shipowners/operators may further increase costs to those participating in the U.S. market. PFC has not taken account of these open ended costs in our assessment.

In the sections that follow PFC energy has analyzed industry data on both LNG tankers and other ships to estimate what the additional costs of a Jones act tanker might be. No LNG tanker has been built in any US shipyard since 1980, when General Dynamics delivered the last two of 10 LNG tankers constructed under the since-discontinued construction differential subsidy program. This program, which would likely be disallowed under World Trade Organization rules if attempted today, endeavored to subsidize the construction and operation of US-flag ships to defray additional costs of running a US-flag vessel and maintain a US-flag commercial fleet.

PFC Energy considers it highly likely that the first yard to do so will have a higher cost base for the construction of new tankers above and beyond the difference in wage costs due to the costs of starting a new specialized product line. We show in this section that to deliver the proposed LNG to the West coast and Canada that 11 LNG tankers will be required to be built specifically for this purpose. The assessment that follows shows PFC Energy's views on what the cost reductions would be as each successive tanker is built.

We will show that we believe that these tankers will cost on average some 54% more than a foreign built equivalent. The first will be 113% more expensive and the eleventh will be 35% more expensive.

In this assessment we have assumed that all tankers, even to Kitimat in British Columbia, Canada, will need to be Jones Act compliant. The Jones Act applies to shipments between US destinations and because British Columbia (and Canada as a whole) is an exporter of natural gas to the United States, incremental gas supplies received in British Columbia will be destined for onward shipment to the United States. PFC Energy expects that even if Kitimat LNG's gas is sold to Canadian customers, the resulting increase in exports of Canadian-produced gas to the United States would trigger the Jones Act.

In order to clarify the issue, PFC Energy requested an opinion from US Customs and Border Protection's Office of Regulations and Rulings, Cargo Security, Carriers and Immigration Branch. This opinion has not been produced in time for this report.

6.2 LNG Marine Transportation Costs

PFC Energy has used its own cost estimates and economic models to assess the likely costs associated with shipping Alaskan LNG supply to various market entry points on the West Coast of North America. Due to the Jones Act stipulations on the construction of marine tankers for domestic transport of any product, Alaskan LNG must be shipped to the US via US built tankers. PFC Energy has estimated the effects of this rule on the costs of shipping LNG.

As with the LPG shipping costs discussed in section 5, PFC Energy modeled LNG shipping costs on the basis of three main variables:

- Capital Costs

- Operating Costs
- Voyage Costs

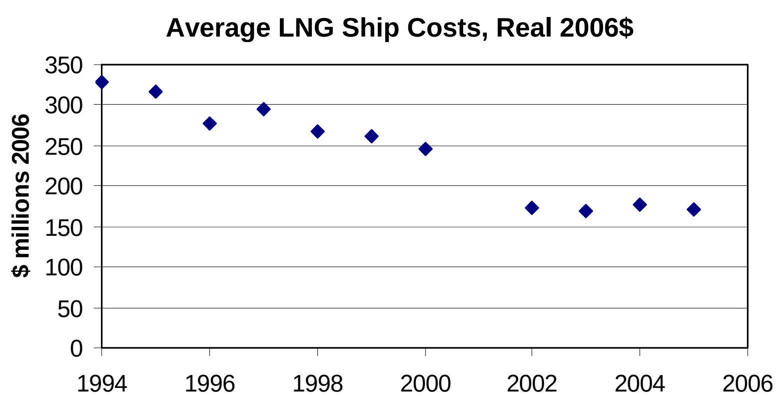
In the sections that follow, we take each of these and discuss them accordingly.

LNG Capital Costs

In modeling LNG tanker capital costs, PFC Energy has executed the work on the assumption that each ship built for this project will have a capacity of 160,000 cm of LNG. Based on the publicly available new-build LNG carrier order book, there are currently 26 LNG tankers on order with the approximate scale of 160,000 cm (the range includes tankers between 150,000 – 175,000cm) for which cost information was available (all of which are to be built in a foreign yard). Average costs for this sized tanker are reportedly $202mm. In the cost comparisons that follow we have assumed that costs remain constant in real terms, so by default we have not accounted for the possibility of higher than expected inflation levels, the potential for material cost increases, and or higher labor costs in the country of construction (US or abroad).

Trends in the US

LNG shipping costs have substantially reduced over the last 10-20 years, some 50% in real terms over a period of ten years.



Note that the above graph has not been corrected for tanker size. The LNG industry is building larger capacity ships, resulting in lower per unit LNG shipping costs than what is illustrated in the graph.

This can be attributed in part to:

- Technology and other efficiency gains in construction
- A reduction in costs associated with a learning curve associated with building many tankers
- A reduction in costs associated with an increasing competition between yards

In the case of US shipbuilders none currently has the specific expertise or is setup to efficiently build LNG tankers. There are few (up to 4 yards that potentially could compete for this work). Costs would therefore be higher than an equivalent Asian built tanker.

PFC Capital Cost Estimates

In the assessment that follows we have compared the costs associated with building tankers in the US with that of a Korean yard. In constructing this assessment we have considered costs in the following categories

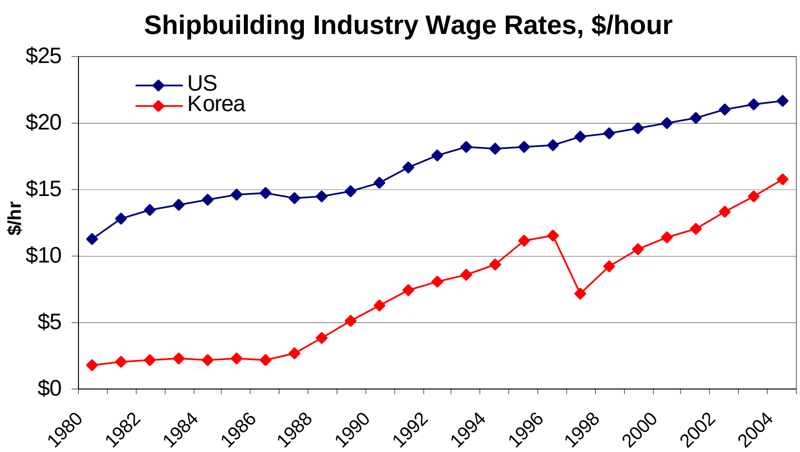
- Additional labor costs – Korean labor is less expensive than the US – what effect would this have on the costs of building US tankers
- Extra costs associated with learning – “the experience curve” – the first tanker would be more expensive than the 11th
- Additional costs associated with a reduced level of shipbuilding capacity in the US
- Additional technical assistance required – use of more expensive consultants from outside of the US particularly on the construction of storage tanks – would be required for the first few tankers

The extra costs associated with these variables would change with the number of tankers built. PFC energy has used various analogies with other industries as well as an analysis of LNG tanker data to estimate the effect of these variables on the costs of building tankers for an Alaskan LNG scheme. We present this analysis below. Note in each case we have isolated the effect of these variables alone.

US vs Korean Labor

As can be seen in the figure below average Korean shipbuilding rates are some 40% lower than the US.

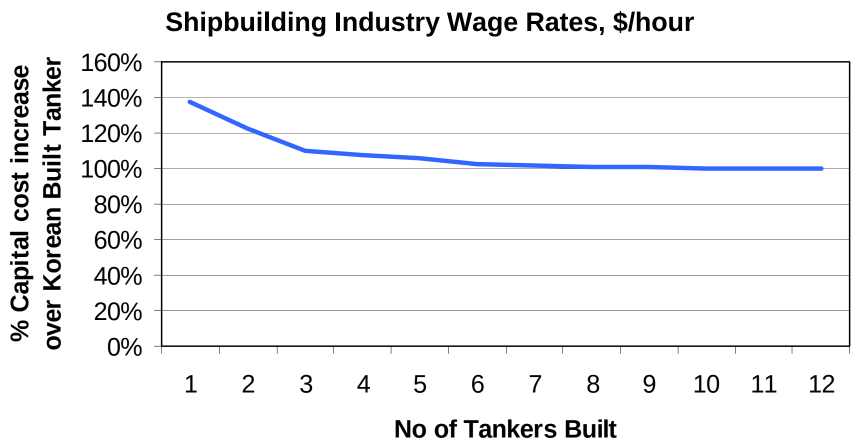
On a typical LNG tanker, Labor makes up an estimated 64% of total capital construction cost. Therefore, with US wage rates for the shipbuilding industry estimated at about 40% higher than those in South Korea, tankers built in the US are likely to cost an additional 25% as compared to the average tanker built in South Korea. Accordingly



*Maritime Business Strategies.

this equates to a capital cost assumption of approximately $250mm. Of course this does not take account of any of the other additional costs to be discussed below.

Learning Curve Cost Reductions



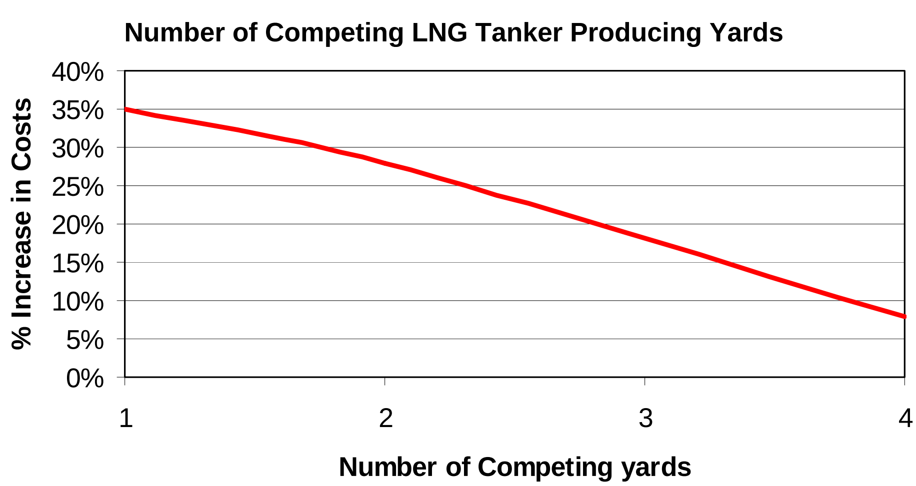
Using data from the LNG industry and experience in the US oil tanker market, PFC has derived a learning curve for the construction of LNG tankers.

We believe that this equates to an average increase in costs of roughly 8% over that of a foreign built equivalent (based on 11 tankers).

Competition between yards

There are currently 12 yards outside of the US in the process of building LNG tankers but there are currently none building tankers in the US. PFC Energy believes that there could be up to 4 yards could be used to construct LNG tankers including:

- Kvaerner Philadelphia Shipyard, PA
- National Steel and Shipbuilding Company, CA



- Avondale, LA
- Newport News, VA

It is clear from global data that there is a correlation between the number of yards and the costs associated with building tankers. Using advanced statistical tools we have isolated the impact of competition between yards and the realized cost reduction affects related. This relationship is shown in the figure below. This correlates well with analogies from other industries

By using one of 4 US yards rather than a foreign builder, PFC estimates that an additional costs of around 8% could be incurred.

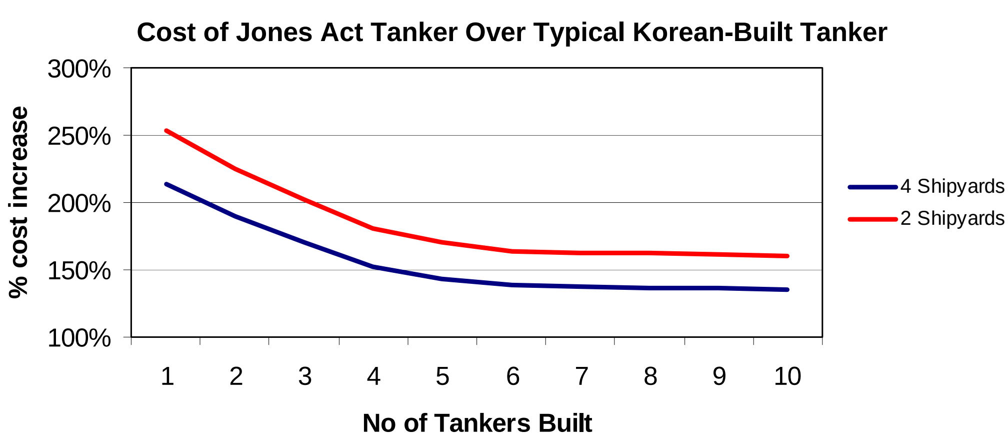
Technical Assistance

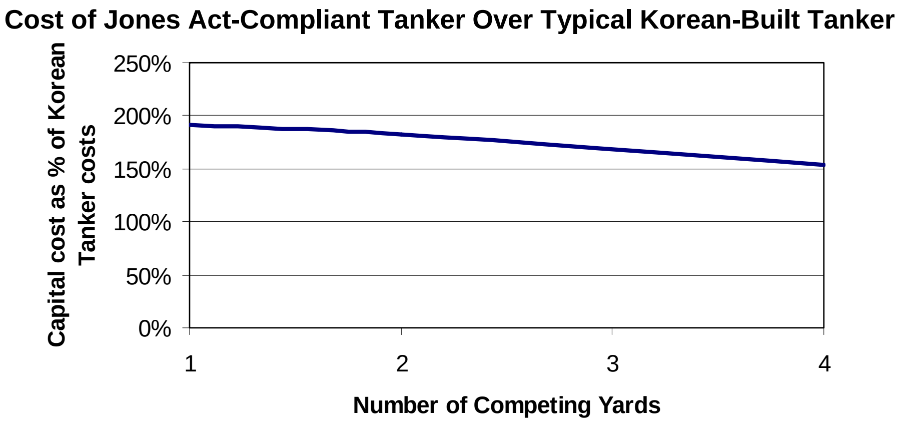
There is a possibility of contracting technical assistance from outside countries, such as France, where the LNG tanker building experience is already established, but where the loss of cost competitiveness has made them willing to help establish new LNG tanker construction capability. This additional expertise would be applied to certain parts of the construction such as the storage tanks. By contracting highly specialized labor at consulting rates, which could be 3-4 times higher than the yard's own internal rates, overall costs for the first few tankers could be 15% higher than an equivalent Korean tanker (PFC Energy estimate). This would likely only apply to the first 2-3 tankers built.

Overall Capital Cost increase

By combining each of the four elements discussed above, PFC Energy has derived an overall cost curve taking into account the number of tankers built and the number of competing US tanker yards. This curve represents the cost of a Jones Act compliant US-built LNG tanker over an equivalent Korean-built vessel.

If we assume that there will be four competing US yards, the average capital cost of building 11 tankers would be some 54% higher than an equivalent Korean tanker. Therefore, 11 tankers would cost some $1.2 billion more than a comparable foreign built vessels.





Operating Costs

Operating and maintenance (O&M) costs also have a considerable wage cost component. With the assumption that a US crew will man LNG tankers transporting the product from Valdez to the US West Coast as per the Jones Act, O&M costs were adjusted accordingly. PFC Energy assumes O&M costs derived from several key variables, including:

- Labor costs related to manning LNG tankers
- Insurance costs
- Costs of repairs and maintenance
- Parts storage and lubes
- Administrative and miscellaneous

Over the life of the vessel operating costs for a US crewed tanker could be some 19% higher than a foreign crewed one.

Voyage Costs

In PFC Energy's economic models analyzing LNG shipping costs, voyage costs are separated from O&M costs due to the uncertainty of fuel costs going forward. Fuel makes up the majority of voyage costs, while port fees make a small portion as well. Important factors relating to annual costs of LNG tanker voyages include distance of travel, speed, cargos per year, unloading/loading port time and fees, and cargo losses. PFC Energy assumptions include:

- Average bunker fuel costs of $230/T
- Time spent in ports = 3 days per round trip (2 for un-loading and 1 for loading)
- Average port fees of $50,000 per call
- Average tanker speed of 19 knots (approximately 22 miles/hour)
- Tankers are available for use for 350 days per year
- Tankers will burn-off approximately 0.15% of cargo volumes per day of journey

In the graphic below, we provide a graphical representation of the annual costs related to LNG tanker voyages at various distance and fuel cost assumptions.

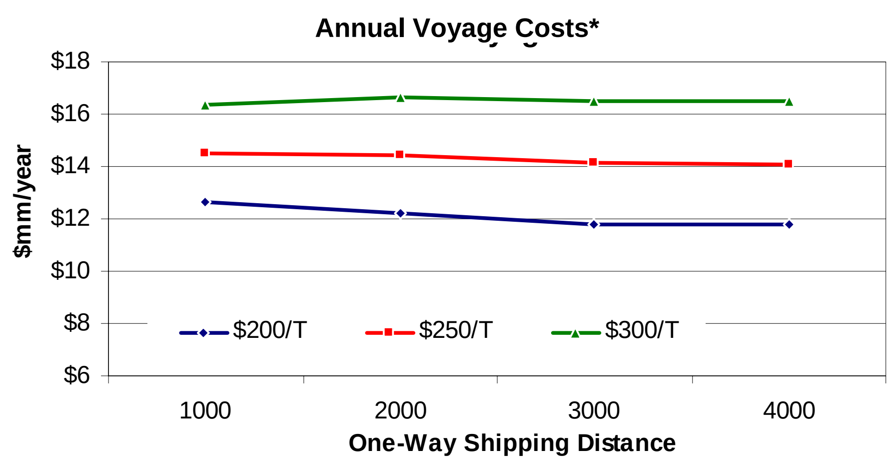
As shown in the graphic above, costs related to LNG shipping voyages could be in the range of $5mm/year higher per tanker depending on bunker fuel cost assumptions. PFC Energy has assumed the low case in providing the economics estimates for this project.

AGPA LNG Tanker Statistics

Terminal	Distance from Valdez, AK	Round-Trip Journeys	Terminal Capacity	Tankers Required	Capital Costs	Jones Act Tankers?
name	*miles*	*# per year*	*MMcfd*	*Number*	*$mm Total*	*Yes/No*
Kitimat	825	57	610	1	$311	Yes
Northern Star	1,400	42	1000	3	$933	Yes
Clearwater Port	2,260	30	1000	4	$1,244	Yes
Port Penguin	2,375	29	750	3	$933	Yes
Total		**158**	**3,360**		**$3,422**	

*Assumes full utilization of tankers for 350 days/year (capacity of 160,000 cm of LNG)

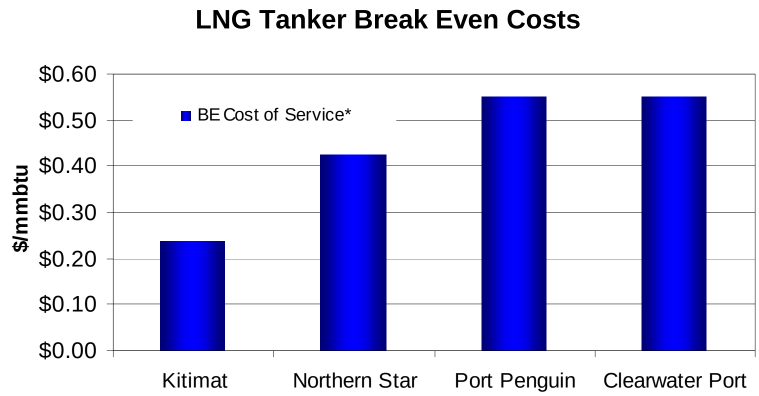
For tanker utilization rates, PFC Energy has assumed that each tanker will be called on to operate as much as possible over the 350 days available per year. This assumption, along with traveling speed, distance, days at



port and other assumptions allowed us to estimate the number of tankers required per target regasification project.

PFC Energy estimates that requirements for tankers to be built in the US under the Jones Act stipulation will increase total LNG tanker costs by approximately $1.2bn (for 11 tankers total).

The following graphic relates the break even cost of shipping LNG from Valdez to the various AGPA port options subject to the following:



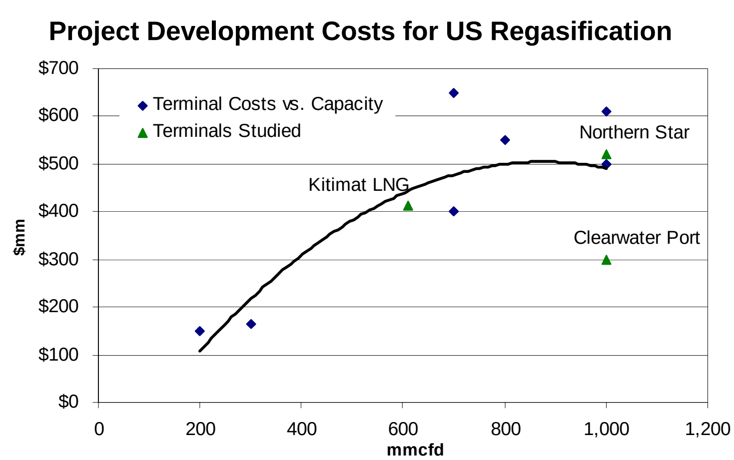
*Based on a tariff required to achieve an assumed required ROR of 8% and PFC Energy capital and operating/voyage cost estimates.

- Takes into account all cost assumptions as mentioned above
- Assumes that the AGPA will order the number of ships required to reach max terminal capacity (1 tanker for Kitimat, 3 for Northern Star, 4 for Clearwater Port, and 3 for Port Penguin)
- Costs assume an after-tax rate of return (ROR)
- Assume a general US corporate tax regime for the tankers

The shipping cost estimates show the difference in costs related to supplying LNG to the various terminal locations mentioned. PFC Energy estimates regarding Jones Act tanker costs have been included in this analysis in order to derive a post-tax break-even unit cost of shipping ($/MMBtu).

6.2 Regasification Terminal Costs

PFC Energy has used its proprietary after-tax cash flow modeling software to generate the break even costs of the four primary LNG receiving terminal projects under review for this report. While each terminal has announced a public domain cost estimate for the planned construction of the terminal, PFC Energy has also generated its own internal estimates based upon the information provided by each project participant. The process for estimating the capital and operating costs of each terminal includes a method of estimating material, labor and other related costs to install each major component of the plant based on various operational factors. The costing includes estimates on process and utility equipment, storage, metering, loading/off-loading facilities, and marine facilities. The estimate will also take into account construction "indirects", i.e. spares, engineering and commissioning, administrative, site



*Port Penguin terminal is not shown above due to lack of public domain cost estimates. All other terminal capital costs are derived from public domain development (including dredging), etc. The information gathered for each terminal was solely that which is in the public domain. In some cases, specific information that is necessary was estimated based upon PFC Energy's understanding and experience in dealing with the design of these types of facilities. A number of factors can have an impact on project costs, including:

- Costs related to raw materials – likely levels of steel, cement, nickel and other raw materials
- Number of storage tanks and size
- Likely costs of dredging and site work
- Length of jetty and marine facilities required
- NGL separation facilities required (if any)
- Pipeline costs (gas and NGL)
- Utilities constructed on site
- Offshore structure construction
- Peak send-out capability

PFC Energy has found that typically the estimations quoted in the public domain are overly optimistic on the part of project developers. In using our internal costing methodology, we can get a better feel for the likely break even costs of each plant on an after-tax basis. The graphic below shows the range of planned West Coast terminal capacities and their associated costs. This wide range implies that regasification project costs are not only related to terminal size, but also to specifics of each site and the characteristics of the terminal (i.e. gas processing facilities, etc.). The graphic below depicts terminal costs related to baseload capacity only, not considering the peak capacity potential for each plant.

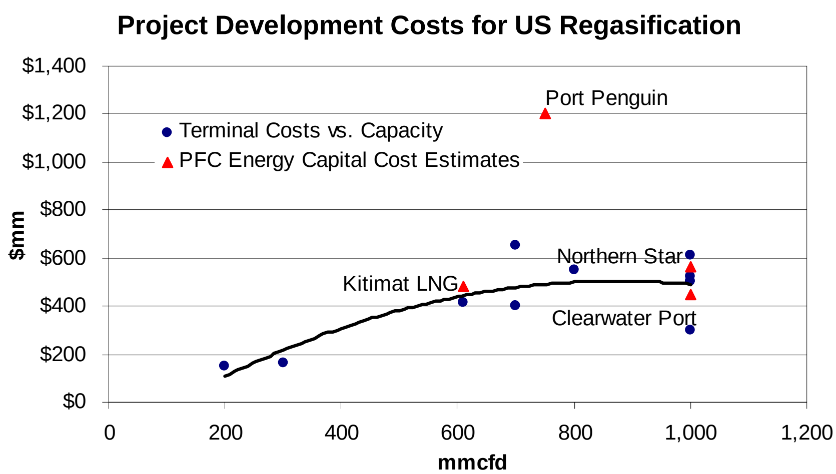
With PFC Energy estimations, the graphic looks somewhat different. As shown below, the red points highlight PFC Energy internal cost estimates. The consistency of our internal cost estimates, even if they are based on limited information, at least put all terminals considered on the same playing field. Many publicly announced capital expenditure figures are related to terminals in the early stages of development where cost estimates may be based on some broad assumptions.

AGPA Project LNG Receiving Terminal Statistics

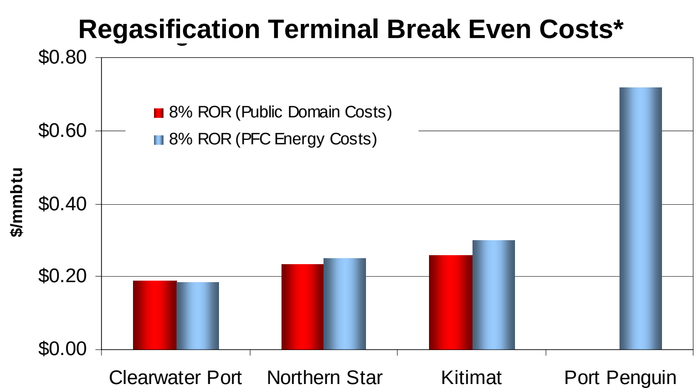
Regasification Cost Estimates	Baseload Capacity	Peak Capacity	Storage	Public Domain Cost Estimates	PFC Energy Cost Estimate	Difference
	MMcfd	*MMcfd*	000 cm LNG	$mm	$mm	%
Kitimat	610	1,000	320	$413	$484	17%
Northern Star	1,000	1,500	320	$520	$561	8%
Clearwater Port	1,000	1,200	0	$460	$450	-2%
Port Penguin	750	1,250	276	n/a	$1,200	n/a

Note: Non-PFC Energy terminal cost estimates were derived from public domain sources

In looking at the specific LNG receiving terminals targeted by the AGPA, PFC Energy has used its after-tax economic model to estimate the break even cost for each regasification terminal, on a $/MMBtu basis. The model does this by assuming a required tariff to meet an acceptable rate of return[3]. Capital costs related to



construction of each project become a major differentiator in terms of the likely regasification tariff (costs) for each terminal. The four terminals modeled in the project have a fairly wide range of reported costs, from $413mm to approximately $1,200mm. These, of course, depend upon the specifics of the project. For example, in looking at the Port Penguin terminal project, one in which very little public information is available, PFC Energy has estimated a cost of $1.2 bn based on other projects around the globe with a similar engineering design. A table of the comparison between PFC Energy and public domain cost estimates follows.

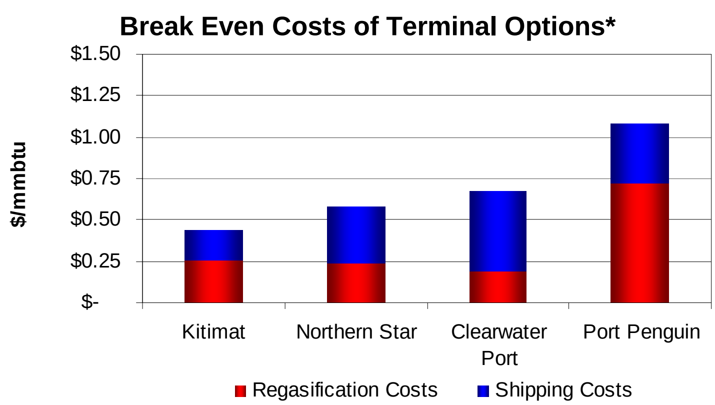


*Based on a tariff required to achieve an 8% ROR on investment. Terminal operating and capital costs estimates derived from public domain sources where available.

[3] *PFC Energy used assumptions provided by the State of Alaska Department of Revenue for the purpose of comparability with the State's tariff for the US Midwest pipeline project used in the netback analysis section (7). These assumptions were and 80/20 debt to equity ratio, 6.5% return on debt and a 14% return on equity for US onshore facilities and a 12% return on equity for Canadian onshore facilities, which works out to a weighted average return of 8.0% in the United States and 7.6% in Canada. PFC Energy adopted 8.0% as the required rate of return for LNG tankers.*

PFC Energy has used the publicly available data to estimate regasification break even costs. As shown in the graphic, cost of regasification, based on tariff requirements to meet required rates of return, range from $0.20 - $0.72 per MMBtu.

When looking at the combined costs for regasification and LNG shipping, three terminals are likely to cost in the range of about $0.45 - $0.70/mmbbtu regardless of the cost estimates used for the modeling. The Port Pelican cost structure is considerably higher, with a likely cost of about $1.40/MMBtu. These figures assume all investment required to transport and regasify the gas necessary to meet full capacity at each regasification terminal. The Kitimat terminal option has a considerable cost advantage in terms of shipping because of its shorter distance from Valdez. In the graphic below, the full break even cost for the LNG shipping and regasification chain for the AGPA project volumes are shown, using public domain regasification terminal costs where available.



*Tanker operating and capital costs are PFC Energy estimates and assume an 8% ROR. Regasification terminal break even costs are based on public domain capital/operating costs (where available) and an 8% ROR.

6.3 Liquefaction Plant and Marine Terminal Cost Review

In the AGPA report outlining the proposed plan for the LNG project in Valdez, it was noted that Bechtel carried out a detailed engineering, procurement and construction (EPC) study in order to estimate the costs related to development of the AGPA LNG plan. This study was updated in 2005, and PFC Energy has used its costs as a basis for some of the netback and project economics assumptions. While the Bechtel estimate was updated less than a year ago, it is very possible that this study does not capture some of the more recent trends realized in the development costs of LNG export facilities throughout the world. Based on various industry press and company sources, PFC Energy has followed these cost trends closely. There are several factors which have driven up the costs of liquefaction facility development in recent months. Some LNG projects which have come into service in the past year have reached record efficiency in terms of costs (i.e. Egypt LNG) on a $/ton of LNG capacity basis. However, it is clear that currently, this environment no longer exists. The rapid rise in costs is related to a number of factors both directly and indirectly linked to the growth of LNG development activity. Some of the recent increased cost pressures realized include:

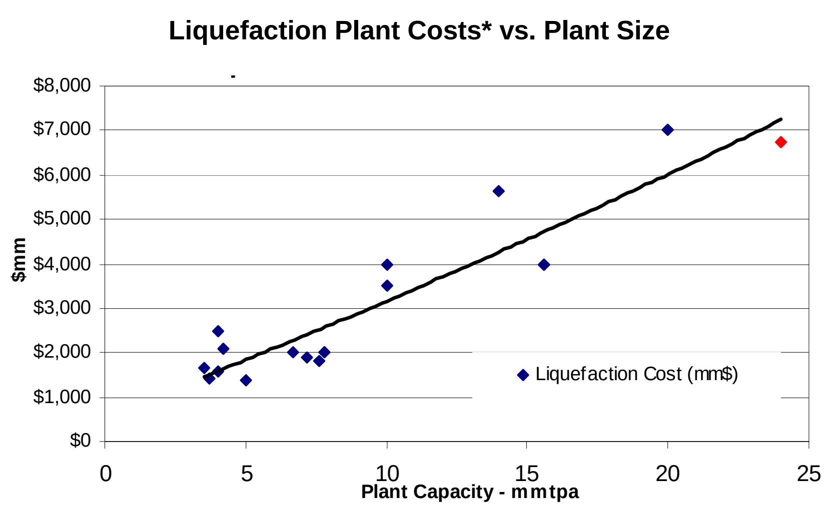
- Raw material costs including steel, cement and nickel have seen major price increases
- EPC contractors with the capability of developing LNG facilities are limited and the near-term build-out will likely continue to constrain that sector of the energy services business, causing prices to rise
- High oil prices are maintaining demand for similar services and materials for a wide variety of energy projects throughout the world (i.e. drilling rigs, platforms, pipeline construction, etc.)

The graphic below represents recent trends in the costs related to LNG developments. Several projects that have taken a final investment decision to develop LNG export facilities in 2005 have announced costs per ton far exceeding what had become the industry norm of around or below $250/ton of capacity. In September 2005, the Yemen LNG project signed and EPC deal calling for costs of about $2bn for a 6.7 mmtpa two-train facility. This equates to $300/t of liquefaction capacity. This trend is likely to continue in the near term as the boom in LNG construction continues, led by Qatari, Nigerian, and other project developments.

According to the AGPA documentation of the proposed LNG project, total costs of liquefaction (does not include upstream, pipeline, and other project costs) would be approximately $280/ton of LNG capacity. This is considerably lower than some of the recent project costs per ton quoted in the public domain. PFC Energy cost assessments are explained in the section below.

PFC Energy Pipeline, Liquefaction/LPG and Gas Conditioning Plant Cost Assessments

As mentioned in prior sections, PFC Energy has performed a cost assessment of total project costs. While some of the specific details regarding the project specifications were not always available, PFC Energy estimates are based on standard project requirements in terms of materials, site developments, utilities, labor costs, location factor (adjustments for extreme weather conditions) etc. A comparison of the cost estimates from Bechtel and PFC Energy are presented in the following table.



Liquefaction Plant Costs* vs. Plant Size

Liquefation/Pipeline Cost Estimates	Max Capacity	Distance of Pipeline	Bechtel Cost Estimates	PFC Energy Cost Estimate	Difference
	MMcfd	*miles*	$mm	$mm	%
Gas Processing Plant	3,800	n/a	$5,100	$5,165	1%
Valdez Pipeline	1,100	806	$8,600	$7,921	-8%
Valdez Pipeline Expansion	2,700	806	$3,200	$3,493	9%
Anchorage Spur	500	175	n/a	$387	n/a
Liquefaction & LPG Terminal	3,300	n/a	$6,720	$7,855	17%

Project Economics / Netbacks

PFC Energy was asked to calculate a netback to the well-head for two scenarios. The first scenario includes the full construction of the North Slope Gas Pipeline project with gas supply start-up to Chicago in 2014. The second scenario assumes that the same volume of North Slope gas is transported to four select terminals in western markets of North America beginning in the same time horizon. To estimate this netback, PFC Energy made use of cash flow models (where appropriate) to calculate post-tax tariff for each segment of infrastructure in the project required to generate the required rate of return. This cost is expressed in this section on a $/MMBtu basis.

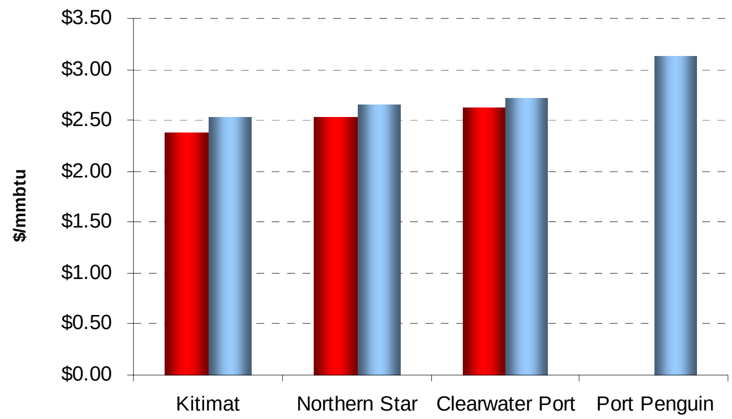
The pre-tax economics (or before considering payment in lieu of taxes, also called PILTs) and the annual $370 mm distribution to the state of Alaska) for the AGPA liquefaction project (based upon stated costs of $280/ton) includes costs broken out between:

- 806-mile pipeline transporting North Slope wet gas to Valdez
- Valdez LNG export facilities
- Valdez LPG export facilities
- Pipeline spur to Anchorage

A gas conditioning plant is needed on the North Slope to remove carbon dioxide and other impurities and chill the gas below freezing in order to preserve the permafrost in which the pipeline will be laid. The GCP has been assumed to be built by North Slope producers and used on a tolling basis by the AGPA project. PFC Energy has calculated the likely cost economics based on the published costs provided by AGPA ($5.1bn) for the GCP associated with this project. The fee for the GCP is shown in the graphic below. The calculation of the tariff required for this plant was made in a similar manner as other infrastructure estimates to this point, using a ROR requirement assumption. This generated a cost assumption of $0.58/MMBtu.

The total capital expenditure (capex) for all facilities constructed by the AGPA in Alaska will amount to approximately $18.4 bn. This capex also includes LPG extraction and export capabilities which will be associated with the LNG project, but assumes no additional investment for LPG extraction capabilities in

Comparative Integrated Break Even Costs of Terminal Options, $/MMBtu



Anchorage on the assumption that existing facilities can be adapted. The capex figure does include funds required to build the 350 MMcfd pipeline to Anchorage from Glennallen based on PFC Energy's estimate of maximum economic demand (shown in Section 7). Thus, the economics of the gas supplies after production through the liquefaction process are as shown below. Note that the gas tariff requirements also take into account assumptions on LPG revenues and the positive cash flow effects for the project.

The graphic below assesses costs of the full value chain ex-field, based on the assumptions explained throughout this section. The costs include the economic benefits realized by the sale of LPG in both Valdez and Anchorage. This revenue in effect nets out a portion of the costs (approximately $0.44/MMBtu) for delivering the LNG. More information regarding LPG sales is provided in the following section.

PFC Energy has estimated total costs from the point of gas inlet to the GCP for moving gas to the West Coast of the US at a range of between $2.38 and $3.13/mcf ex-regas (based on a 8% ROR), depending on the terminal of destination. This calculation does not include the estimated cost of upstream development for gas supplies. In other words, in order for producers to achieve a positive netback on gas supplies produced from the North Slope, gas prices in the destination market after regasification must remain above approximately $3.00/mcf, depending upon the import terminal, plus the cost of gas production.

6.4 Valdez LPG Extraction Facility Cost Review

As discussed in section 5, PFC Energy did account for the revenues generated from LPG export in association with LNG production. AGPA has lumped expected costs of LPG facilities into the total liquefaction costs in recent documentation. Therefore, PFC Energy has used its internal estimate to calculate the likely cash flow effects of LPG export on this integrated project. Based on PFC Energy models and specific knowledge of this type of facility, the CAPEX estimate for LPG export from Valdez was set at $720mm. In Anchorage, a processing fee was assumed for LPG extraction, but this figure was considerably smaller than costs at the Valdez plant considering the difference in LPG volumes.

7. Alaska Netback Comparison: Pipeline vs. LNG

The critical evaluation of project netbacks for the Alaskan North Slope gas supplies in this section provides a comparison between the two options for transporting gas to the lower-48 US markets – via pipeline or LNG. Some of the key factors include costs and economics as outlined in the previous section (6). Also important are the likely prices which can be expected for revenue generation in each project – that is the market price is netted back to the North Slope producers. Because of the difference in destination of the gas supplies in the two cases (North Slope pipeline to the Midwest and LNG to the Pacific Northwest and California), market characteristics also play an important role in generating price and revenue expectations. Regional market fundamentals and the impact of these increased gas imports from Alaska will have a marked effect on project netbacks. In order to carry out the complex analysis of the impact of these two options for Alaskan North Slope gas, PFC Energy has used a number of models, methodologies and interacting sets of data to establish our internal assumptions for the netback evaluation of these two projects. Throughout this section we will explain both the results from our various model analysis, as well as the methodology and assumptions used in each case.

7.1 North America Natural Gas Model Overview

Uncertainty regarding supplies, prices, inter-fuel competition, regulation, and a number of other variables requires a rigorous analysis of newly developing fundamentals in the US gas market. In order to address the uncertainties inherent going forward in this market, PFC Energy has utilized an established set of dynamic market risk assessment models and frameworks. With the assistance of these tools, PFC Energy is able to better understand the most critical pressure points in the market and in particular how basis pricing points, such as Stanfield, OR, may evolve through time. These tools, along with our proprietary set of detailed US market supply/demand databases, have been used to generate a detailed analysis of the US Gas Market. This assessment has split the country's markets into 10 separate regions as is shown below. The analytical output has been used to show the impact of variations of supply from Alaska on likely price paths going forward for supply, demand and US gas prices under different assumptions.

In particular we have looked at two main scenarios:

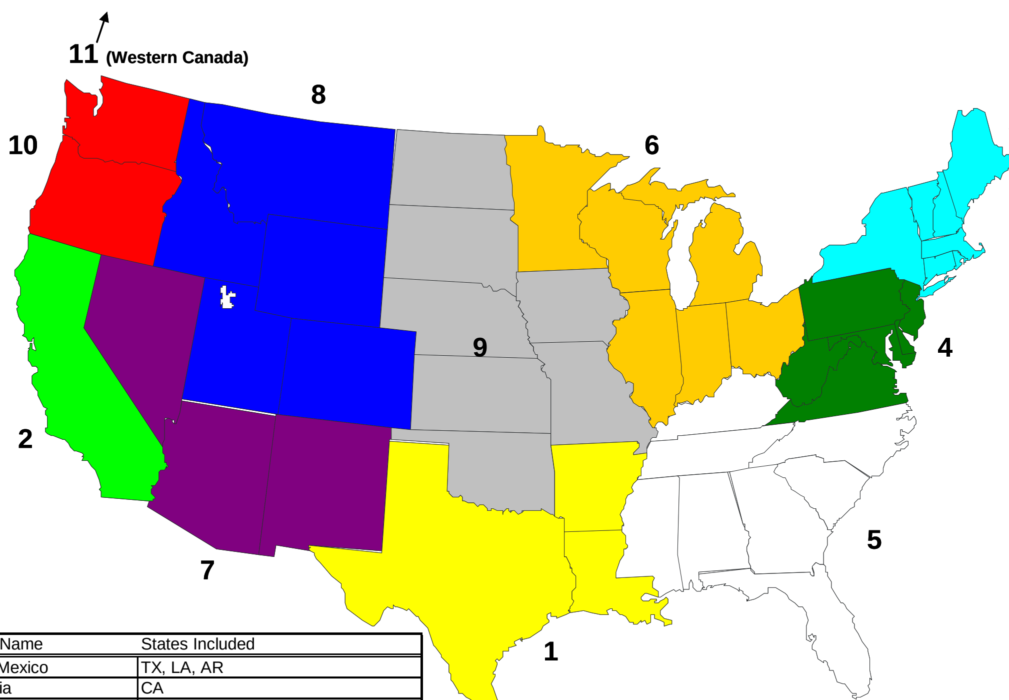
- The first scenario envisages the transport of Alaskan gas via the Alaska Highway Pipeline (or North Slope Pipeline) to connect with the Canadian Mainline (with the majority of supplies moving to the US Midwest (Chicago)
- The second scenario modeled looks at the option of sending that gas via LNG to the US West Coast (including the four terminals mentioned in previous sections) for marketing in California and the Pacific Northwest

The dynamics of the North American gas model allow us to track the market reactions and price effects in different regions based upon the different scenarios.

PFC Energy's US gas model includes but is not limited to:

- Development economics for ~3,000 gas supply tranches including supply by basin, LNG import and Canadian projects
- Demand which is responsive to price, by region
- The impact of technology on price and volume
- Regional constraints (related to physical infrastructure) on production and LNG imports
- Global LNG potential to the US

The graphic below shows the regional breakdown used within PFC Energy's North America Gas Model framework. While this project focuses on the West Coast (for LNG import) and the Northern Plains (for the pipeline import case)

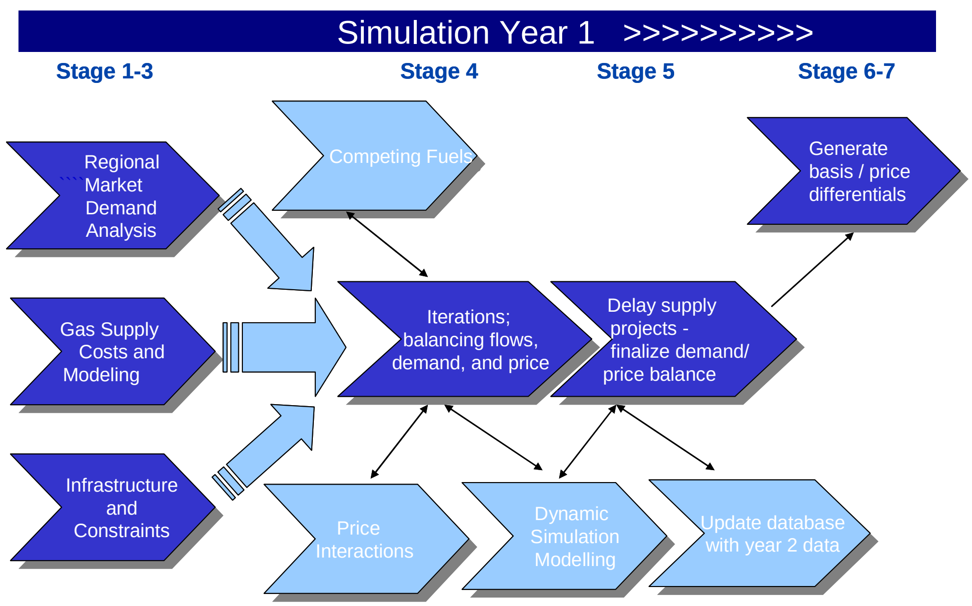


Regin Number	Region Name	States Included
1	Gulf of Mexico	TX, LA, AR
2	California	CA
3	Northeast	ME, NH, VT, MA, CT, RI, NY
4	Mid-Atlantic	NJ, PE, DE, DC, MD, VA, WV
5	Southeast	NC, SC, KY, TN, GA, AL, MS, FL
6	Northern Plains	OH, IN, MI, WI, MI, IL, MN
7	Southern Desert	AZ, NM, NV
8	Mountain	MT, ID, WY, UT, CO
9	Central Plains	ND, SD, NE, IA, MO, KS, OK
10	Pacific Northwest	WA, OR
11	Western Canada	Alberta and British Columbia

regions, it was necessary to model the entire gas system throughout the lower 48 states (and Canada) in order to generate the necessary price, volume, and gas flow results. PFC Energy takes into account the potential flows to and from all regions, as well as imports from other provinces in Canada, and LNG imports. The model runs iterations to analyze the likely movements of gas based on demand, supply, transport and other variables as each relates to the changes in gas pricing (per year). For example, while Alaskan pipeline gas may not reach the markets of the Northeast, a large import of gas into markets in the Northern Plains could increase the availability of gas supplies from other areas, i.e. the Gulf of Mexico region. This dynamic interaction takes place throughout all regions as the model balances flows throughout the gas market and deciphers the likely costs at each regional pricing point.

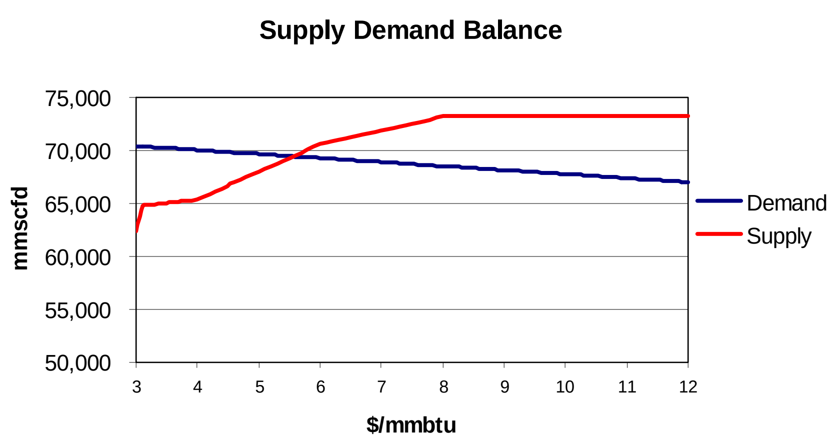
Detailed Gas Market Model Methodology

As shown by the simplified schematic below, PFC Energy's North America Gas Market model uses a complex structure to analyze the likely interactions between market players and variables in different region. The final output of this specific version of the model, which was customized for this project, derives a gas price differential (basis) to the Henry Hub price, which is typically deemed the key benchmark for gas prices in the country.



Gas Supply Component

With each year simulated, an inventory of potential supply tranches for that year is assessed. Included in this data is the location, potential markets served, costs to market (including transport), etc. This includes not only projects currently under development, but also PFC Energy's views on likely future exploration activity, costs of bringing on new reserves, and likely LNG and pipeline imports that have yet to be contemplated. This analysis requires that PFC Energy take a stance on several areas that are highly uncertain. However, because of the model's interaction with both price and market consumption dynamics, we feel that this is the best way to analyze the potential for certain gas supplies to be developed over a long-term horizon. One of the model's dynamic characteristics is to simulate the interaction between potential buyers and sellers of gas in order to come to a balancing point for each regional market, for prices, flows and demand. This works by taking into account the buyer's desire to minimize costs, while the sellers in each of the major supply regions will look to maximize profits by diverting gas supplies to the highest value market. The demand/supply balances change as price filters through the equation and as new potential supply tranches are assessed each year. The supply database includes not only new gas supply volumes, but also looks at the likely price effects that each market will have on projects currently producing (committed) and the likely volumetric flows of all supplies due to dynamics in the market. In each year of simulation, markets will balance, with buyers looking to fulfill regional demand via the cheapest gas available. For gas supplies that were too expensive to be selected, project development is delayed and the project goes into the database for the following year. The simplistic basis for this modeling is shown in the graphic of the available. For gas supplies that were too expensive to be selected, project development is delayed and the project remains available for development in the following year. The simplistic basis for this modeling is shown in the graphic of the supply/demand price curve below. This fundamental piece of analysis is carried out in each region for every year modeled.



Gas Demand Analysis

Regional demand projections take into account a number of factors related to the specifics of each gas market in the previously designated regions. Some of these factors include:

- Power development and likely future alternatives to gas-fired power (new-build and existing facilities)
- Economic growth in the region
- Likely sensitivity to various gas supply costs (i.e. at what level does gas loose competitiveness)
- Competing fuel options (power and other)
- Requirements for various weather extremes (i.e. peak demand in hot or cold climates)

Infrastructure Constraints

Infrastructure in place and planned for the future is a key variable for the modeling of the US gas market. Because of the unique regional characteristics of each market, the basis prices for the regions examined will be impacted a great deal by available infrastructure. For example, the map below shows the detail used to analyze the impact of gas infrastructure on the Pacific Northwest and California gas model (model regions 10 and 2 respectively).

While the work of analyzing the gas price differential for California and the Pacific Northwest includes technically only three states (and two regions), a host of other issues from various regions are at play. Pipeline connections with Texas link California to the country's largest gas supplying region (largely from the Permian Basin). Therefore, market dynamics in other areas of the country (i.e. the northeast or Chicago) could affect the California market and prices could react accordingly. Also important are California and the Pacific Northwest connections with major supply basins in the Rocky Mountains (Mountain region), Western Canada, and New Mexico (Southern Desert). Other infrastructure questions include timing and availability of LNG supply (both for export terminals and import facilities), pipeline expansions, and other dynamics which could interfere with long-haul gas supplies. One specific example includes the potential for increased demand for gas in Western Canada, likely to be a result of the rapid build-up of new Canadian Oil Sands projects currently under development. This will likely change the availability and costs of gas from the traditional Alberta basins where the US Northwest gets a substantial portion of gas supply. This is an example of one of many issues that has been contemplated and modeled in PFC Energy's process of balancing gas supply/demand for each region. The model also allows us to track the market's likely reaction to a major new supply tranche, i.e. the effects of brining North Slope gas to the lower-48 states.

Gas Market and Price Optimization

In each year, regional supply and demand forecasts were generated taking account of the costs of supplies and demand's sensitivity to prices. Flow of gas around the US subject to production and transmission constraints was optimized to produce the lowest cost to the system. Gas prices at the key nodal points were then calculated to clear the market. This process represents the potential for arbitrage across the liquid trading points.

Drivers of Market Price Projection Results

Results from this regional market interaction model can vary widely depending upon the input data and assumptions used. Some of the assumptions made by PFC Energy in this modeling effort include (for the base case):

- Increased access to Rockies region acreage for oil and gas development

- A regionally balanced flow of LNG through various entry points around the US, including 1 terminal in Pacific Northwest region and terminals with California access
- Alaskan pipeline volumes to Chicago starting in 2014
- Demand forecasts by region and that demand's sensitivity to various gas price levels
- The underlying cost of gas supply to the US, including domestic supplies from conventional fields, CBM, tight sands, shale, and other un-conventional gas plays, as well as LNG and other import costs
- Transport costs and constraints, assumptions on the likely new-build infrastructure
- Global LNG supply (spot and long-term) availability and responsiveness to US gas price volatility
- More efficient use of natural gas in residential and commercial sectors
- More efficient use of electricity in all sectors
- Technology gains and their impacts on future cost of supply
- Assumptions regarding land access, market regulation, and other important political uncertainties
- Analysis of competing fuels and the likelihood of gas to maintain, increase or decrease competitiveness
- Historical relationship between various market pricing points and a view on how those will adapt going forward
- Views on oil prices and general energy market developments over the long-term

7.2 Natural Gas Price/Basis Differential Forecast and Analysis

PFC Energy used its regional North America gas pricing model to generate forecasts for regional prices in West Canada, Pacific Northwest, California, and Chicago (Northern Plains region) from 2014 - 2030. This was carried out using the two scenarios discussed, the first related to the Alaska pipeline project and a second being the Alaska LNG project supplying California and the Pacific Northwest with both project scenarios starting in 2014. The graphics below show the comparison between price forecasts for each scenario modeled. Because of the impact on the regional markets of entry for such a large volume of gas, the price forecast for each scenario is considerably different. This is significant because these price curves are used in generating the netback forecasts to North Slope producers in each of the two scenarios. Over the period of 2014-2030, the average forecasted gas price at the relevant market points is as shown in the table.

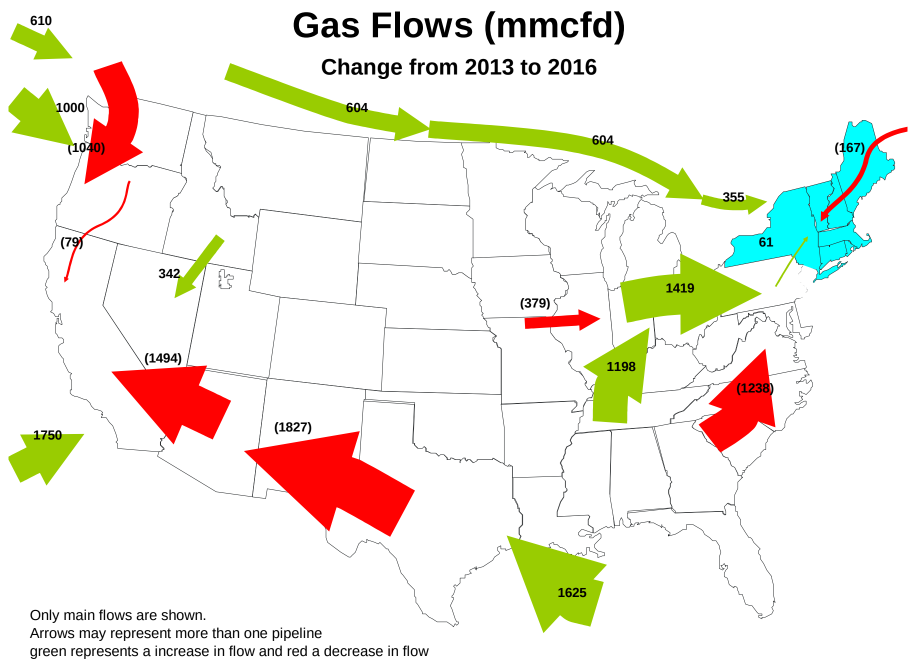
Substantially similar levels of total US and Canadian natural gas production, LNG imports (excluding Canada) and production underpin both scenarios for the sake of comparability. There are naturally regional differences between the two scenarios, but a conscious effort was made to maintain comparability for the sake of a fair comparison between the two projects. Furthermore, a relatively simple demand projection algorithm was used to further reduce the potential for regional market result differences that do not result from supply side issues.

Changes in US Gas Market Flows

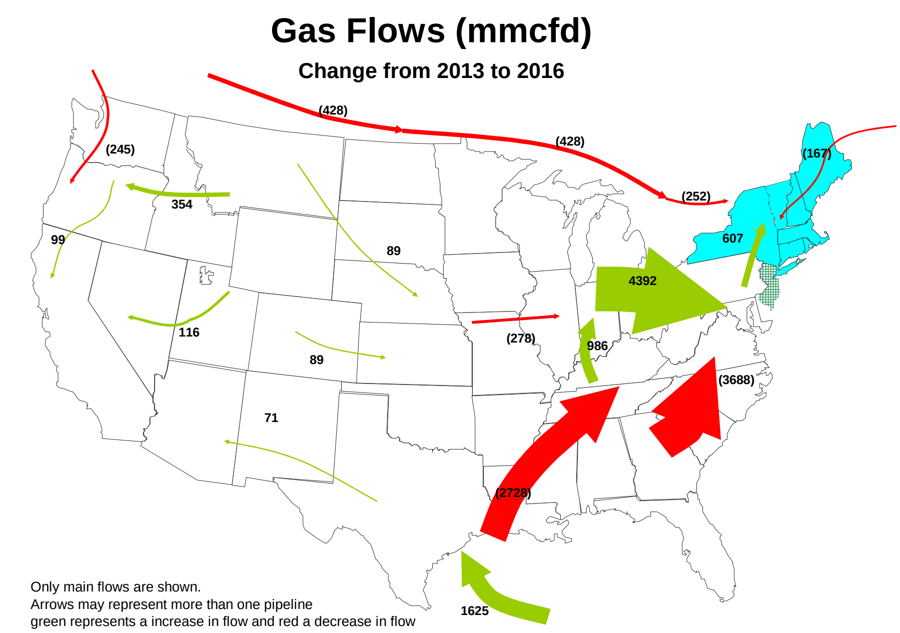
Each of the Alaskan gas transportation projects would result in significant changes in North American gas market flows as the new supplies displace existing to find their most efficient destinations. To that end, this section will focus on the change in flows between 2013 and 2016, when the impact of each project will be most evident.

With the AGPA project, PFC Energy's gas market model has AGPA gas supplies displacing volumes from the Gulf Producing region and, to a lesser extent, from West Canada. The decline from West Canada nearly matched the volume of gas from the Northern Star terminal in Oregon, appearing to be a straight displacement. Similarly, the decline in volumes transiting the Desert Southwest from the Gulf Producing region into California are a rough match. Volumes into Kitimat displace West Canadian production into the Northern Plains and points east. Indeed, the Kitimat terminal seems to be the only one that results in incremental volumes moving east of the West Coast; gas from Northern Star and the California terminals remains on the West Coast and displaces

Changes in Natural Gas Flows 2013-2016: AGPA Scenario
Million cubic feet per day



Changes in Natural Gas Flows 2013-2016: Chicago PL Scenario
Million cubic feet per day



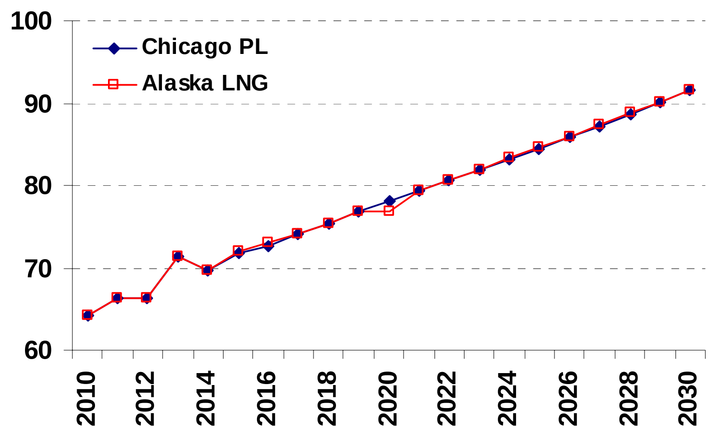
other gas volumes from the Canada or the Gulf Coast.

Changes in flows due to the Chicago pipeline are almost entirely east of the Mississippi. The Alaskan supply into Chicago pushes Gulf Coast supplies out of the Mid-Atlantic region at the expense of Gulf Cost flows to the Mid-Atlantic via the southeast. Some of the New Alaskan supplies move into the Northeast via the Mid-Atlantic, but most stays in the Mid-Atlantic, displacing Gulf Coast supplies. The high cost of incremental Gulf Coast production makes it vulnerable to displacement in the model, and it is projected to decline as new Alaskan supplies ramp up. On the West Coast, Western Canada increased volumes to the Pacific Northwest and California driven in part by displacement from traditional Northern Plains markets by the new Alaskan volumes.

Gas Demand

US Gas demand is almost identical between both scenarios, averaging nearly 2% per year in the long term. This is similar to the long term average regional growth rates observed in the model output. Though the demand algorithm used is price sensitive, regional differences in demand between the two scenarios remained quite small, averaging less than 0.2%. Had some of the larger gas price basis impacts resulting from major new supply tranches been more persistent, larger regional demand variations may have emerged, but the basis impacts of the introduction of each Alaskan supply scenario is substantially reduced within 4-8 years of the start of each new supply tranche.

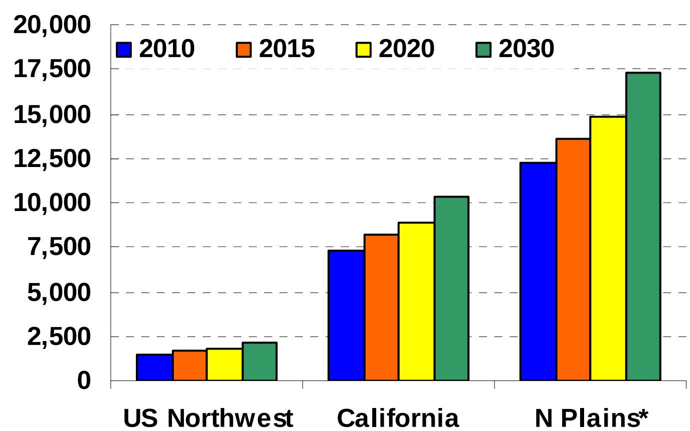
US Natural Gas Demand By Scenario
Billion cubic feet per day



LNG Imports (Excluding Supplies From Alaska)

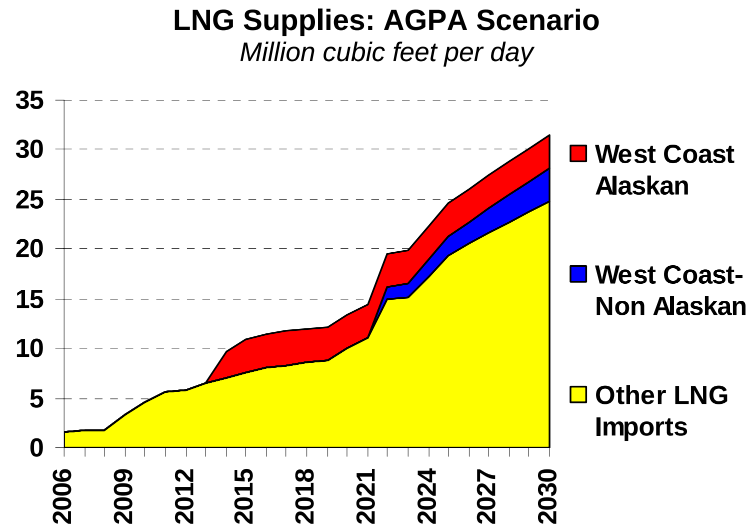
The profile of non-Alaskan LNG supplies is similar in each of the scenarios evaluated. Total LNG supplies are understandably higher in the AGPA case, reflecting the project's volumes. There are minor differences in the increase in LNG volumes between the two scenarios reflecting the model's behavior in crossing thresholds to call for additional LNG supplies, but the overall pattern was made quite similar.

Gas Demand in Key Regions
Million cubic feet per day



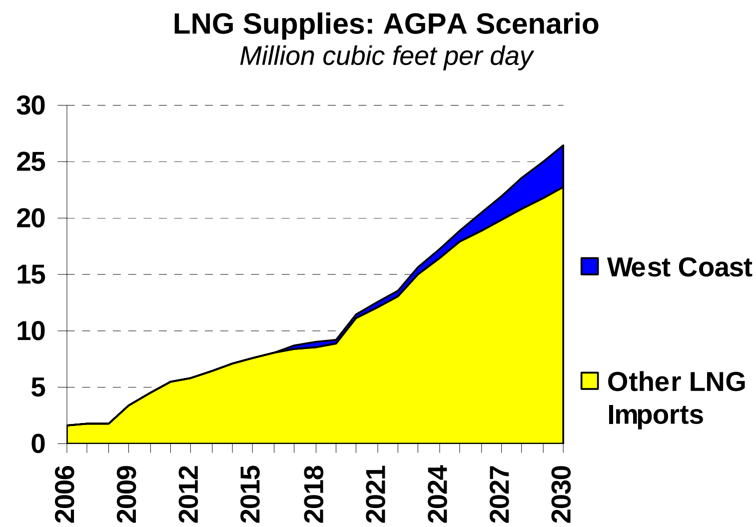
** Includes Chicago*

The average difference in non-Alaskan LNG volumes between the two scenarios is less than 700 MMcfd, with the AGPA scenario having the higher average. The largest differences between the two scenarios come after 2020.

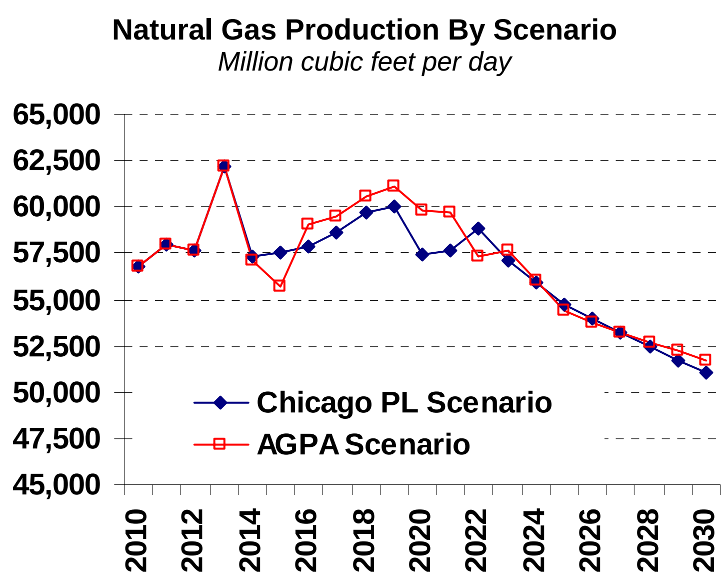


Gas Production

Natural gas production is similar for both scenarios, but not identical. After the assumed 2014 startup of each project, the AGPA scenario typically, but not always, has slightly higher production. By 2023, however, the two scenarios are nearly identical.

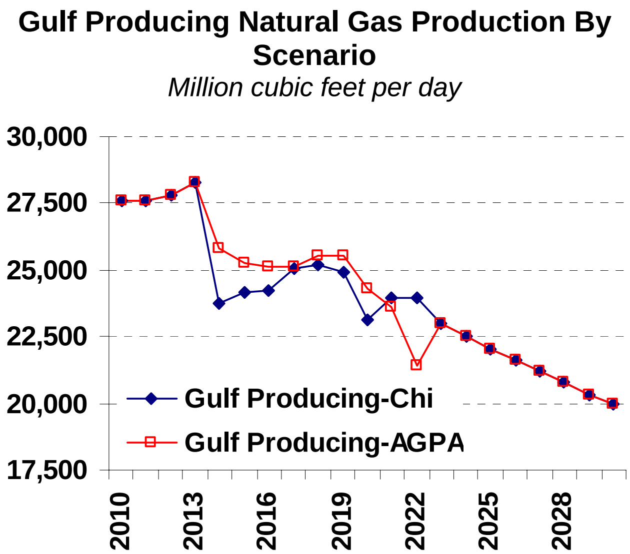


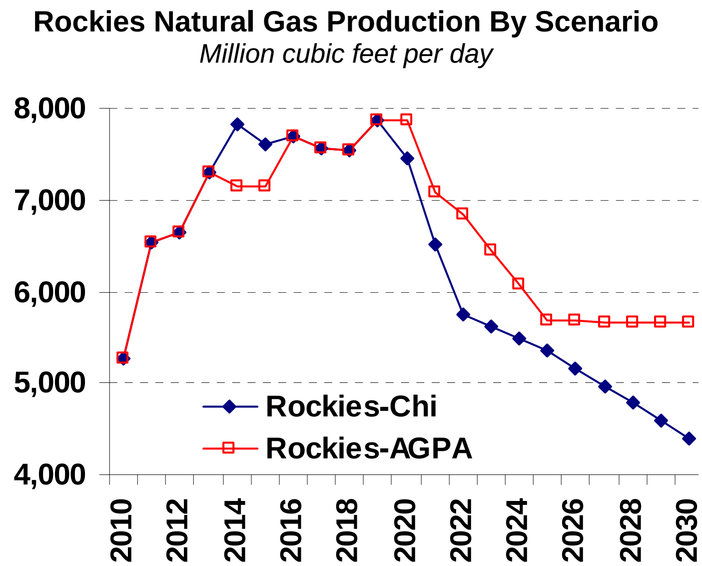
As with the LNG figures, the model's thresholds for triggering new supply tranches are the same in both scenarios, but the model reaches these triggers at different but similar points. PFC Energy endeavored to keep the production levels as similar as possible between the two scenarios as the model allowed.



In both scenarios, the Gulf Producing region sees protracted declines, due in large part to the high level of production and declining reserves. As discussed in the flows section, both scenarios displace more gas from the Gulf Producing region than other regions. Additionally, most of the growth in LNG imports comes into the Gulf Coast region, competing with local production.

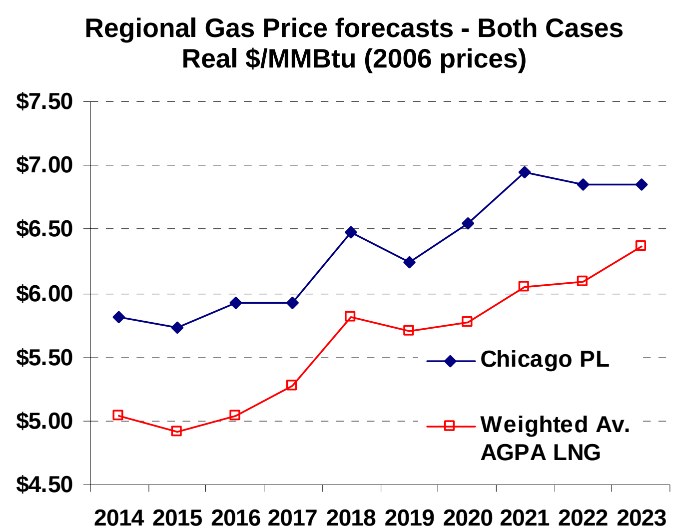
The Rockies region production results show a bigger difference between the two





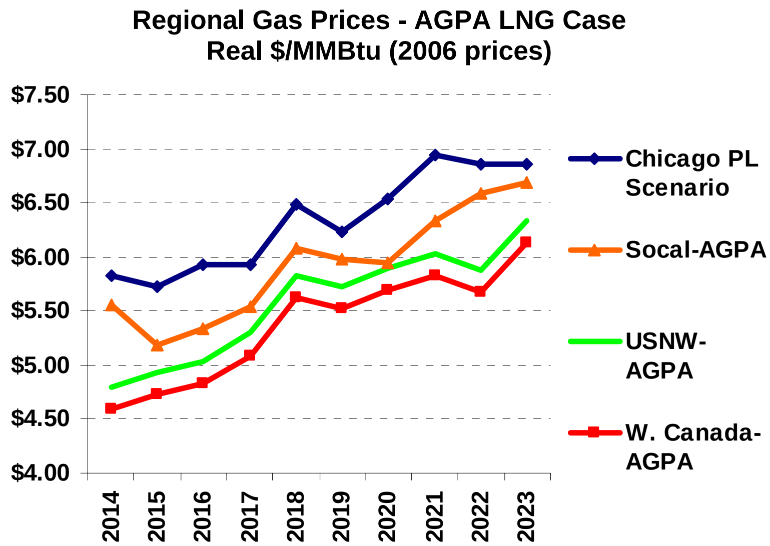
scenarios, but because the difference emerges after 2019, this difference is not directly attributable to incremental volumes from new Alaskan supplies.

Gas Prices



Both the AGPA and Chicago pipeline scenarios come in a rising price environment, but the Chicago pipeline case leads to higher average realized gas prices for the sale of Alaskan gas. For the first ten years of operation, the average natural gas price realized by the Chicago pipeline is $0.73/MMBtu higher than in the AGPA project. Much of this difference is attributable to location. Almost half of the AGPA project's sales are in a net exporting region like Kitimat in British Columbia or a gas transit area like Northern Star in Oregon. Gas from both of these locations must travel considerable distances to market areas or compete with other sources of supply transiting the region to serve local demand.

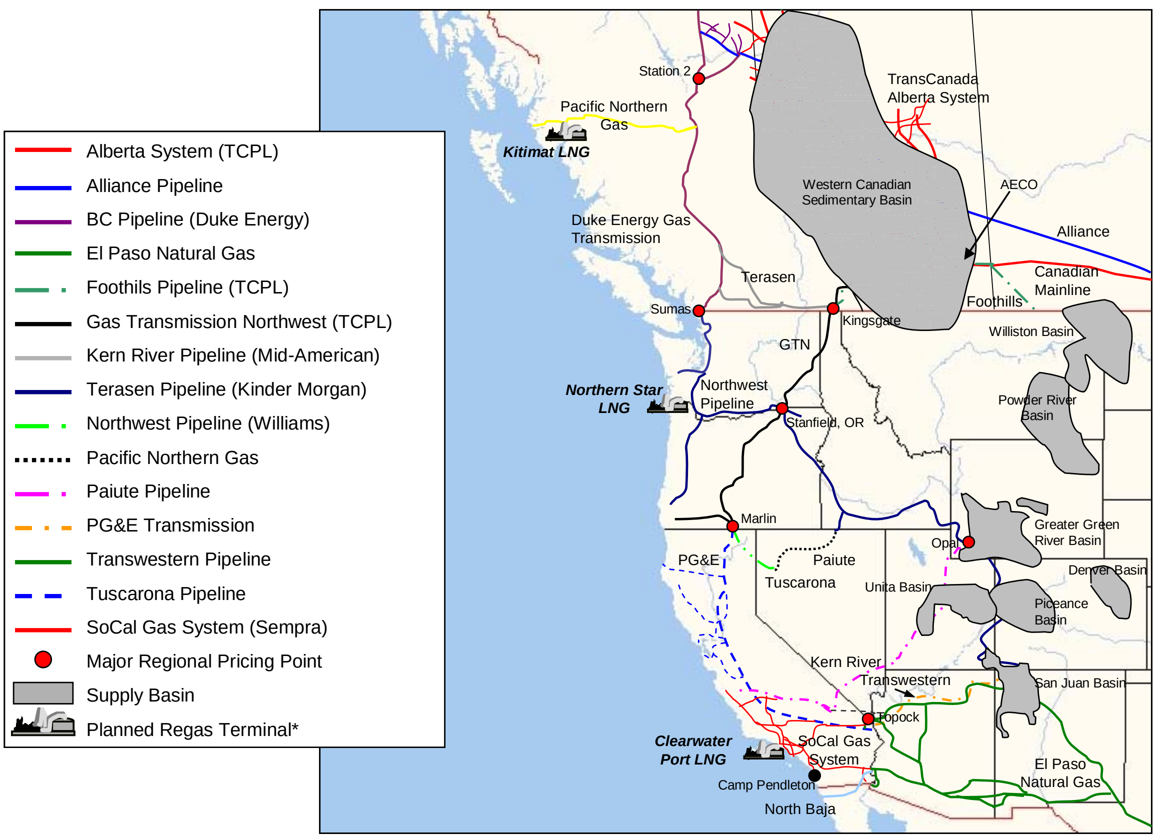
Average Price Forecasts	**Real $/MMBtu (2006)**		
	2014-2020	***2021-2030***	***2014-2030***
Chicago Pipeline Scenario	$6.10	$6.87	$6.54
SoCal AGPA	$5.03	$5.99	$5.60
Northern Star AGPA	$5.66	$6.65	$6.24
Kitimat AGPA	$5.05	$6.01	$5.62
Weighted Average LNG Markets (LNG Scenario)	$5.36	$6.34	$5.93



The two California terminals realize the highest prices of all the AGPA sales, but even there, the size of the incremental supply relative to the market can be seen weighing upon the SoCal price in the earliest years of the project.

These marker projection results are contingent on the timely construction of necessary infrastructure. PFC Energy expects that given the lead time required for either Alaskan gas transportation project, companies would incorporate the incremental supplies in their pipeline capacity planning activities, smoothing the transition. If companies do not do so, then the introduction of Alaskan supplies could prove more disruptive than indicated here, and price discounts for the new gas supplies would be greater than projected here in the first 3-5 years of either new project.

US West Coast and Western Canada Existing Gas Pipeline Infrastructure



*Includes only LNG import terminals with which AGPA has signed an MOU regarding LNG supply.

7.3 Anchorage Gas Market Issues

In order to simplify assumptions, PFC energy projected Anchorage gas demand and local production in order to assess the opportunity for North Slope gas as per the AGPA plan. In this work, in addition to internal analysis, PFC Energy drew upon the South-Central Alaska Natural Gas Study commissioned by the US Department of Energy and released in June 2004.

Anchorage area gas demand can be broken into four principal components including:

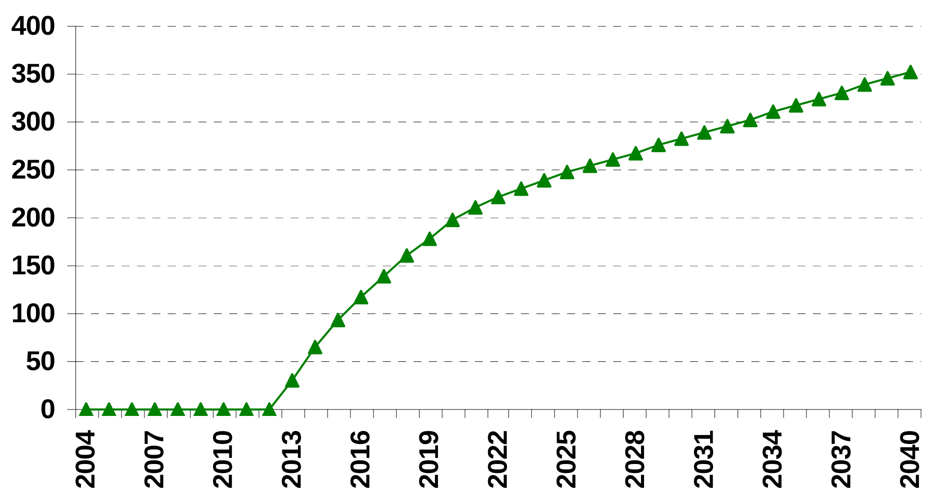
- Direct gas demand supplied via the ENSTAR distribution company
- Gas used for power generation
- The Kenai gas liquefaction plant exporting LNG to Japan
- The Agrium ammonia/urea fertilizer plant

The first two categories have very different economics than the last two; the first two are based on local demand which, if not met with gas, must be met with other energy sources at prevailing local prices while the last two are based on being competitive on a cost basis with similar projects elsewhere in the world.

Pipeline gas distribution needs are projected to grow for the foreseeable future. One of the main applications for this gas is space heating, the need for which will continue given the climate of Anchorage. A combination of economic and population growth will drive continued growth in this category.

Gas used for power generation is projected to remain near current levels. Given the structural change in gas prices expected in this period with the shift from stranded Cook Inlet gas supplies to North Slope supplies which could alternately be sold into the lower 48 gas market, gas will lose the cost advantage it has enjoyed for the last several decades, curbing future growth.

Projected Anchorage Area Demand For North Slope Natural Gas
Million cubic feet per day

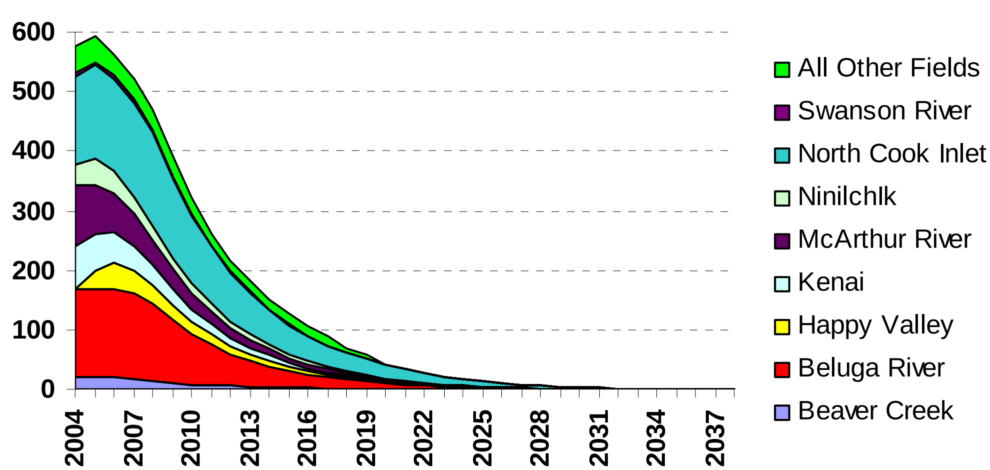


The Kenai gas liquefaction plant has been in service for 37 years, and is approaching the end of its economic service life without major refurbishment. As the first commercial LNG export plant in the world, it has already had a very long service life, and even projects that started operation after it have seen output decline due to depletion of available gas supplies (most notably Arun in Indonesia). PFC Energy believes that with structurally higher gas supply costs, the plant probably could not conduct a major refurbishment and continue to operate profitably with both higher capital and gas supply costs. It may have been able to sustain one or the other (depending on magnitude) but with numerous other international LNG supply options setting the threshold for viability, the substantial cost increases faced by the Kenai plant make its continued operation highly unlikely. Accordingly, it has been assumed to cease operation by the end of is decade.

The Agrium fertilizer plant faces similar gas supply cost threats to its economic viability, as do plants elsewhere in the United States and Canada. Countries with stranded gas supplies that are not large enough to support an LNG based gas export project frequently monetize these resources by constructing large methanol or ammonia plants to capitalize on low gas costs to minimize total production costs and then export the output to destinations around the globe. North American gas-based petrochemicals such as ammonia and methanol producers have been among the parts of the economy with the most adverse impact from higher natural gas prices in the last several years, and this has happened despite the fact that most of these plants are more than 20 years old, and are fully amortized so that they have a capital cost advantage over newer plants.

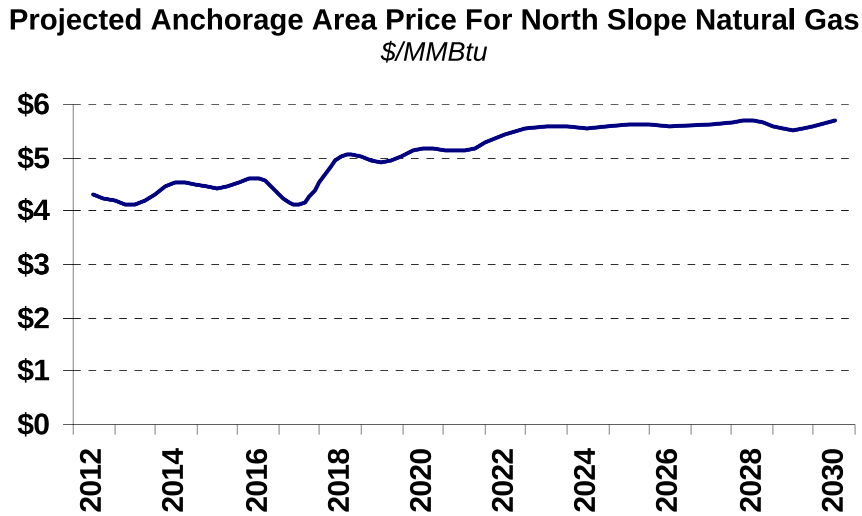
The Agrium plant is in a similar position of facing substantially higher gas costs, but also has the disadvantage of not being in a demand center; while a US plant in the lower 48 can sell its output locally, the Agrium plant must ship its product to relatively more distant markets. PFC Energy considers the Agrium plant unlikely to remain in operation past 2006 or 2007 barring major Cook Inlet gas discoveries. Documents on Agrium's website dated November 2005 indicate that the company was expecting the shutdown of one ammonia and one urea train in November 2005 and the other pair in November 2006.

Projected Cook Inlet Natural Gas Production
Million cubic feet per day



Source: DOE South-Central Alaska Natural Gas Study, PFC Energy

In the graph of projected Anchorage area gas demand, the shutdowns of the Agrium fertilizer plant and the Kenai LNG plant are clearly visible, as they reduce gas use to less than half of its original level. Continued growth in local demand for piped gas is expected to continue, however, driving Anchorage area gas demand higher from 2010 into the future.



Cook Inlet gas production, the source for Anchorage area natural gas supply, is on the verge of precipitous decline due to the depletion of identified gas fields. The breakout by field is illustrated below, making clear that nearly every source, including the large fields that have long sustained Cook Inlet production, will be in terminal decline by 2008, and that areawide production should be in terminal decline after this year.

Additional discoveries can alter this production profile substantially if sizeable new gas resources are discovered. In order to encourage exploration, ENSTAR, the local gas distributor, has agreed to index prices to Henry Hub in Louisiana. Though the exact formula is not clear, the objective of offering to pay higher, market-linked prices is clear. The issue of exploration potential has a direct bearing on Anchorage area demand for North Slope natural gas, because local production is likely to be available at lower prices than North Slope supplies. A very large Cook Inlet gas discovery, though unlikely, could undermine the commercial rationale for bringing in North Slope gas supplies.

Given the demand and supply projections above, the difference constitutes the Anchorage area gas demand potential for North Slope gas. Indeed, these figures may overstate demand as the Cook Inlet production figures are gross production figures rather than net of field uses such as lease fuel and reinjection, but the net result is that the Anchorage market for North Slope gas is substantially less than the 500 MMcfd envisioned in the AGPA plan, even in 2040. For the purposes of the project evaluation, PFC Energy reduced the size of the spur line to Anchorage to 350 MMcfd and reduced the line's cost accordingly.

To derive the wholesale price of natural gas delivered to Anchorage, PFC Energy assumed the same North Slope gas price as the netback yielded by the LNG sales, plus the cost of pipeline transport down the main pipeline to Glenallen and then down the spur line to Anchorage. The result is illustrated below.

7.4 Value Comparison for Alaskan Gas Monetization Options

Section 6 outlines PFC Energy's "break even" costs associated with the Alaskan LNG capital cost estimates provided by the AGPA. These were utilized to assess the likely economics of the plant to export approximately 3,300 MMcfd of LNG to the west coast of North America. The state of Alaska Department of Revenue also provided PFC Energy with a tariff assumption for the Alaska gas pipeline project of $2.67/MMBtu for gas deliveries to Chicago.

Netbacks and Break Even Cost Estimates Assuming an 8% ROR*

Alaska LNG Project Netbacks (Using Bechtel and Public Domain Costs Where Available)	Break Even Price
Gas Conditioning Plant	$0.58
Pipeline (North Slope to Glennallen)	$0.69
Pipeline (Glennallen to Valdez)	$0.14
Anchorage Gas Pipe	$0.03
Anchorage LPG (Credit)[1]	($0.02)
Liquefaction Plant (Valdez)	$0.65
LPG Export Plant (Valdez - Credit)[1]	($0.49)
Unit Costs of PILT and Annual Payments	$0.37
Weighted Average Shipping Costs[2]	$0.47
Weighted Average Regas Costs	$0.35
Total Break-Even Costs	**$2.76**
Average Price Ex-Regas Facility	**$5.93**
Netback to Well-head	**$3.17**

Alaska Pipeline Project Netbacks	Break Even Price
	$/MMBtu
North Slope Pipeline (to Chicago)[3]	$2.67
Chicago LPG Sales (Credit)[1]	($0.82)
Total Break-Even Costs	**$1.85**
Average Price Chicago City-Gate	**$6.54**
Netback to Well-head	**$4.69**

1 - LPG sales revenues exceed the gas processing plant tariff, resulting in net revenues
2 - Shipping calculations assume an 8% ROR
3 - Provided by the Alaska Department of Revenue, includes estimate for North Slope GCP plant costs.

LPG Sales Estimates

A major difference between the two scenarios, other than the difference in pipeline and other infrastructure tariff cost structures, is the revenue generated via LPG production from the two projects. The Chicago pipeline credit per unit of gas sold based on LPG production is about 56% higher than that of the Alaska LNG project. This stems mostly from a difference in ethane extraction assumptions. Typically, ethane stripping from gas volumes is only logical if there is adequate chemical plant and other industrial facility offtake capacities in proximity to the LPG extraction plant in order to utilize the extracted ethane. Because of the characteristics of the product, ethane is fairly difficult to ship via tanker to markets where chemical production capacity is available.

Valdez does not have petrochemical facilities that can extract ethane's incremental value above natural gas prices. PFC Energy assumed it would be left in the natural gas stream, increasing average heat content from 1,000 Btu/cf to 1030

Operating and Capital Cost Comparisons for Both Projects

Alaska LNG Project Operating and Capital Costs	Annual Operating Costs	Total Capital Costs
	$mm	*$mm*
Gas Conditioning Plant	*$109*	*$5,100*
Pipeline (North Slope to Valdez)	$177	$8,600
Pipeline Expansion (to Valdez)	$48	$3,200
Anchorage Gas Pipe	$6	$387
Anchorage LPG (Credit)*	$30	$0
Liquefaction Plant (Valdez)	$330	$6,000
LPG Export Plant (Valdez - Credit)	$40	$720
Unit Costs of PILT and Annual Payments	$746	$0
Weighted Average Shipping Costs	$18	$3,421
Weighted Average Regas Costs	$35	$2,607
Total Break even Costs	**$1,539**	**$24,935**

Btu/cf. However, facilities in proximity to the Chicago gas market would be able to utilize the ethane supply. Therefore, our assumption is that the Alaska LNG project has no revenue related to ethane sales, while the Chicago pipeline project does.

Netbacks and Break Even Cost Estimates
Assuming an 8% ROR – PFC Energy Cost Estimates*

Alaska LNG Project Netbacks (PFC Energy Costs)	Break Even Price
Gas Conditioning Plant	$0.58
Pipeline (North Slope to Glennallen)	$0.67
Pipeline (Glennallen to Valdez)	$0.14
Anchorage Gas Pipe	$0.03
Anchorage LPG (Credit)[1]	($0.01)
Liquefaction Plant (Valdez)	$0.75
LPG Export Plant (Valdez - Credit)[1]	($0.47)
Unit Costs of PILT and Annual Payments	$0.37
Weighted Average Shipping Costs[2]	$0.47
Weighted Average Regas Costs	$0.36
Total Break-Even Costs	**$2.88**
Average Price Ex-Regas Facility	**$5.93**
Netback to Well-head	**$3.05**

Alaska Pipeline Project Netbacks	Break Even Price
	$/MMBtu
North Slope Pipeline (to Chicago)[3]	$2.67
Chicago LPG Sales (Credit)[1]	($0.82)
Total Break-Even Costs	**$1.85**
Average Price Chicago City-Gate	**$6.54**
Netback to Well-head	**$4.69**

1 - LPG sales revenues exceed the gas processing plant tariff, resulting in net revenues
2 - Shipping calculations assume an 8% ROR
3 - Provided by the Alaska Department of Revenue, includes estimate for North Slope gas conditioning plant costs.

7.5 Conclusions

Based on the above analysis, PFC Energy has come to the following conclusions:

- The AGPA project offers a significantly lower netback to North Slope gas than the Chicago pipeline project; PFC Energy estimates a netback to North Slope gas via the Chicago pipeline of \$4.69/MMBtu, as opposed to \$3.17/MMBtu for the AGPA project based on public domain asset cost estimates where available (i.e. AGPA for liquefaction facilities, LNG terminal project sponsors for terminal costs, etc.). Using PFC Energy's internally generated asset cost estimates for the AGPA project, the difference widens, with the AGPA netback dropping to \$3.05/MMBtu.
- The average price received by the AGPA project for gas sold into the West Coast is an average of \$0.61/MMBtu lower than that realized by the Chicago pipeline project, due primarily to regional gas price differentials and the greater average distance of AGPA sales form major consuming centers relative to the Chicago pipeline project.
- The breakeven cost for the Chicago pipeline project to trans port gas (net of LPG revenue) is \$1.85/MMBtu. A levelized tariff of \$2.76 would be needed for the AGPA project based on public domain costs, and \$2.88 based on PFC Energy's asset cost estimates. Either way, the Chicago pipeline project has a decisive cost advantage.

Appendix: US Customs and Border Protection Letter On Jones Act Applicability For Alaskan LNG Shipments to British Columbia

PFC Energy requested advice from US Customs and Border Protection regarding the applicability of Jones Act requirements to LNG shipments from Alaska to British Columbia in light of British Columbia's position as an existing exporter of natural Gas to the United States. PFC Energy provided information regarding the project where available and also provided additional information as requested by Customs. The letter from US Customs and Border Protection presenting their findings and basis for those findings is attached.

U.S. Department of Homeland Security
Washington, DC 20229

U.S. Customs and
Border Protection

VES-3-RR:BSTC:CCI
116619 GOB

MAR 13 2006

George Beranek
PFC Energy
1300 Connecticut Avenue., N.W.
Suite 800
Washington, DC 20039

Dear Mr. Beranek:

This letter is in reply to your correspondence of February 16, 21, and 22, 2006, on behalf of the State of Alaska's Department of Revenue.

This letter is an "information letter," as that term is used in section 177.1(d)(2), Customs and Border Protection ("CBP") Regulations (19 CFR 177.1(d)(2)). We believe that an information letter is more appropriate than a ruling in this instance.

In your letter of February 16, 2006, you state in pertinent part as follows:

> I am writing to inquire as to the applicability of the Jones Act to a proposed project that we are currently evaluating. It calls for the marine transportation of liquefied natural gas (LNG) from Alaska to British Columbia, Canada, where it will be regassified at the receiving terminal, processed to extract ethane, and then fed into the British Columbia/Canadian natural gas transmission grid.
>
> Because British Columbia is an exporter of natural gas to the United States, some of this gas may enter the United States; as natural gas is a fungible commodity, it will not be possible to track the Alaskan natural gas molecules to their ultimate destinations. Because it could be argued that even if the gas were sold to Canadian consumers, it would result in a net increase in British Columbia natural gas exports to the US, I feel compelled to inquire as to the applicability of the Jones Act to the marine transportation segment of this project.
>
> In addition, I ask you to consider the applicability of the Jones Act in light of the following transformative processes which the LNG will undergo in British Columbia:

- the LNG transported by tanker to British Columbia will be vaporized at the receiving terminal from the liquid to the gaseous phase
- the vaporized project will then be processed in British Columbia to remove ethane, a trace component of the gas (roughly 2.3%) before injecting the remaining gas into the natural gas transmission system[.]

In your letter of February 21, 2006, you state in pertinent part as follows:

> PFC Energy has been retained by the State of Alaska's Department of Revenue to provide an independent assessment of the LNG project proposed by the Alaska Gasline Port Authority (AGPA), and Kitimat is one of the four planned LNG receiving terminals, albeit the only one not located in the United States.
>
> . . . In AGPA's proposal, the project will sell LNG to the four West Coast terminals (including Kitimat), each of which will have the responsibility to market the regassified LNG. From the LNG sales revenues, AGPA will deduct the cost of its facilities (operating costs and capital recovery, as well as payments to the State of Alaska), and pass remaining monies on to the North Slope producers as payment for their natural gas production. In this role, the AGPA project is the buyer of North Slope natural gas and the seller of LNG to the West Coast terminals. Accordingly, under this structure, neither the AGPA nor the North Slope producers will have an ongoing stake in the gas once it arrives at one of the LNG receiving/regassification terminals. The North Slope producers will have an indirect interest in the success of the terminals in realizing high prices for the LNG, but will not have any control over the marketing of the gas.
>
> LNG sent to the Kitimat terminal has been proposed to be contracted to Canadian destinations, but as British Columbia is already a net exporter of natural gas to the United States, this would displace the natural gas currently being used by these Canadian customers into the United States market. . . .
>
> . . .
> The fungibility of natural gas in a pipeline system with multiple receipt and delivery points is complete. It is not possible to track a batch of natural gas in a pipeline from a receipt point to a delivery point as is sometimes possible in oil pipelines. Instead, volumes into and out of the pipeline are tracked, which ensures that volumes delivered to the pipeline correspond to the gas received at the other end. As a result, some of the Alaskan gas molecules delivered into British Columbia will

> enter the United States (lower 48) even if the Kitimat terminal contracts the Alaskan gas to Canadian consumers. Kitimat's sales of regassified Alaskan LNG to Canadian customers grant those customers rights to withdraw set volumes from the pipeline; it is not physically possible to determine the origin of the molecules withdrawn from the pipe, whether Alaskan or Canadian.

Title 46, United States Code Appendix, § 883 (46 U.S.C. App. § 883), the coastwise merchandise statute often called the "Jones Act," provides in part that: "No merchandise . . . shall be transported . . . between points in the United States . . . either directly or via a foreign port, or for any part of the transportation, in any other vessel than a vessel built in and documented under the laws of the United States and owned by persons who are citizens of the United States . . ."

The coastwise laws generally apply to points in the territorial sea, which is defined as the belt, three nautical miles wide, seaward of the territorial sea baseline, and to points located in internal waters, landward of the territorial sea baseline. The "territorial waters" to include the internal waters and the navigable waters of the United States.

Section 4.80b(a), CBP Regulations (19 CFR § 4.80b(a)) provides, in pertinent part:

> A coastwise transportation of merchandise takes place, within the meaning of the coastwise laws, when merchandise laden at a point embraced within the coastwise laws ("coastwise point") is unladen at another coastwise point, regardless of the origin or ultimate destination of the merchandise.

Section 4.80b(a), CBP Regulations (19 CFR 4.80b(a)) provides as follows:

> **§ 4.80b Coastwise transportation of merchandise.**
>
> (a) *Effect of manufacturing or processing at intermediate port or place.* A coastwise transportation of merchandise takes place, within the meaning of the coastwise laws, when merchandise laden at a point embraced within the coastwise laws ("coastwise point") is unladen at another coastwise point, regardless of the origin or ultimate destination of the merchandise. However, merchandise is not transported coastwise if at an intermediate port or place other than a coastwise point (that is at a foreign port or place, or at a port or place in a territory or possession of the United States not subject to the coastwise laws), it

> is manufactured or processed into a new and different product, and the new and different product thereafter is transported to a coastwise point.

We note initially that if the marine transportation from Alaska to British Columbia is performed by a coastwise-qualified vessel, there is no prohibition of 46 U.S.C. App. § 883. In this regard, you may wish to contact the Maritime Administration of the U.S. Department of Transportation (Michael Hokana; 202-366-0760) with respect to the availability of coastwise-qualified vessels.

We referred the issue of the regassification of the LNG to CBP's Laboratories & Scientific Services (LSS). LSS has determined as follows:

> In order to perform a Jones Act "new and different product" analysis in this instance, the characteristics of the product must be compared as it leaves Alaska and as it enters into the pipeline system. As it leaves Alaska, the product is considered LNG which is essentially a gaseous product usually containing 90% or more by weight of methane (C1) with small amounts of other gaseous hydrocarbons (ranging from C2 to C4). Since pure ethane is a fairly valuable product and its extraction from the LNG would not result in a significant loss of BTU equivalents to the product, it is more economical to extract the propane for its own properties (production of plastics) than to burn it as a fuel. However, the product after the ethane extraction would remain commercially identifiable and usable as LNG.
>
> Therefore, our review shows that the product before the gasification and extraction and after the gasification and extraction are considered LNG for commercial purposes and are used as such. Accordingly, we are of the opinion that the processing that occurs in British Columbia has not produced a "new and different" article of commerce.

Accordingly, based upon the determination of CBP's LSS, relief from the potential applicability of 46 U.S.C. App. § 883 by the final sentence of section 4.80b, CBP Regulations (see above), is not available because the LNG is not manufactured into a new and different product.

This leaves for consideration the issue of whether the LNG is otherwise considered to be transported in a coastwise movement. Title 46, United States Code App., § 883 provides in part that: "No merchandise . . . shall be transported . . . between points in the United States . . . either directly or via a foreign port, <u>or for any part of the transportation</u>, in any other vessel than a vessel built in and documented under the laws of the United States and owned by persons who are citizens of the United States . . ." [Emphasis supplied.] If the LNG is transported from Alaska to British Columbia by a non-coastwise-qualified vessel, and is subsequently transported by the pipeline to another place in the United States (*e.g.*, one of the lower 48 states) as indicated in your correspondence, such transportation would appear to constitute a violation of 46 U.S.C. App. § 883, because part of the transportation was performed by a non-coastwise-qualified vessel. The violation would occur as to the quantity of LNG which was transported from Alaska to British Columbia and which was subsequently transported to another place in the United States. We understand from the facts presented that the amount of such LNG transported cannot be quantified.

We hope this information is helpful to you.

Sincerely,

Glen E. Vereb

Glen E. Vereb
Chief
Cargo Security, Carriers and Immigration Branch