The Case for a Susitna River Dam:

Does It Hold Water?

Jan Konigsberg
Alaska Hydro Project
Anchorage, Alaska
jan@hydroreform.org

December 2012

CONTENTS

INTRODUCTION

In November 2010, Alaska Energy Authority (AEA) recommended the state should proceed with the so-called "Watana" hydropower dam on the Susitna River near the confluence of Watana Creek.[*] [1]

In May 2011, the legislature passed a bill authorizing AEA to construct, own, and operate a Susitna River power dam and passed a capital budget appropriating $65 million to AEA for licensing and engineering design.[2] On October 27, 2011, AEA filed for a preliminary permit with the Federal Energy Regulatory Commission (FERC).[3] On December 29, 2011, AEA filed its Notice of Intent to submit a license application (NOI) and the Preliminary Application Document (PAD).[+] [4]

The project is estimated to cost at least $4.5 billion (2010$). The hydropower project will use the public's water as an energy source, and is likely to significantly impact other public-trust resources, including fish and wildlife.

Alaska's Sustainable Salmon Fisheries Policy would caution: damming a major salmon-bearing river for power generation should proceed if and only if there is no better power-supply alternative.

No energy supply is without some environmental impact; the best alternative will minimize cost and impact, while providing affordable, stably priced energy for the long-term.

This analysis asks a basic question: Can Alaskans be assured the proposed hydropower project is the best solution to the problem of supplying cost-effective energy to the Railbelt? In other words, is the project the most economically efficient, least-impact alternative to meeting Railbelt energy demand in the next 50 to 100 years? Are there better alternatives Alaskans can buy with their $4.5 billion? Are there alternatives that do not rely on state subsidies?

This report deals only with energy supply. Investing in energy supply, however, must go hand-in-hand with investment in energy efficiency.

Taking a cue from the Railbelt Regional Integrated Resource Plan:[5] this report finds there are significant issues associated with a Susitna River hydropower project, not the

---

[*] The dam will actually be closer to Deadman Creek than Watana Creek.

[+] The legislature had previously appropriated $10 million to AEA for licensing and permitting a large Railbelt hydro project.

least of which is the cost of energy (electricity) from the project. This report does not dispute that a publicly financed and owned energy supply is likely the only approach to achieve affordable, stable, energy-pricing in the long-term, but concludes the proposed Susitna River dam will not achieve this goal.

This goal could be achieved if the state instead were to finance, find, and produce its own natural-gas resource from the Cook Inlet Basin.

With an investment of no more, likely less, than the Susitna dam, the state could develop and produce its Cook Inlet natural gas resource to supply the entire current Railbelt demand for electric power and space heating for the next 100 years at a cost of half or less of the energy from Susitna hydro and with much less environmental impact than a dam will cause to 220 miles of the fish- and wildlife-bearing watershed.

This analysis finds relying on the private sector to bring Alaska's own natural gas – whether Cook Inlet gas resource or North Slope gas reserves – to the Railbelt market to be problematic. Imported liquefied natural gas (LNG) is the only certain source of natural gas that can fill the impending gap between Railbelt energy demand and declining supply of Cook Inlet natural-gas reserves in the near-term and is likely a secure source of gas supply for the long-term as well. Moreover, of the various natural gas-supply options, imported LNG requires the least capital investment and has the least environmental impacts to the Alaska's environment.

This report relies mainly on publicly available information and analysis, primarily secondary sources. Hence, the cost estimates of the various gas-supply options that are examined below must be viewed skeptically. Given the inherent uncertainty of the various gas-supply cost estimates, this analysis is not intended to be a definitive nor precise evaluation of viable alternatives to a Susitna River power dam. Yet, despite the obvious uncertainty about future cost of various energy-supply sources and technologies, there are sufficient grounds to question the wisdom of the State of Alaska proceeding with a large Railbelt hydro project at this juncture.

While the report strives to be accurate and benefits from the expert review of others, whatever errors of fact or other mistakes may be discerned, these are solely the responsibility of the author.[*]

[*] This report is made possible by grant support from the Hydropower Reform Coalition; the views expressed are those of Alaska Hydro Project and not necessarily those of the Hydropower Reform Coalition.

EXECUTIVE SUMMARY

The Susitna River dam project will decrease reliance on natural gas for electric-power generation in the Railbelt by less than 50% at current demand.

The dam will reduce consumption of natural gas for both electric-power generation and space heating in the Railbelt by no more than 25% at current demand.

Natural gas will continue to supply at least 75% of the Railbelt energy requirements for electric power and space heating.

Cook Inlet gas supply from reserves will fall short of demand as early as 2014.

The State of Alaska has determined that the private sector cannot be counted upon to provide new gas supply from in-state sources to meet in-state demand and is pursuing the feasibility of investing in a North Slope to Southcentral pipeline.

$18 billion (2010$) is estimated to be the cost of finding and producing at least 7.5 trillion cubic feet (Tcf) from Cook Inlet Basin gas resource – about 50% of the estimated total undiscovered, conventionally recoverable, conventional, Cook Inlet gas resource.

7.5 Tcf will meet current utility demand for all Southcentral space-heating and all Railbelt electric energy demands for the next 100 years.

Environmental impacts from developing new Cook Inlet gas fields will range from minimal to moderate; while impacts from the proposed hydropower project will be significant.

Imported LNG is available to meet future Railbelt gas-supply demand; importing LNG requires the least capital investment, and has the least environmental consequences of any gas-supply option or a Susitna River dam.

The proposed hydropower dam will take considerably longer to license and permit than other options.

A Susitna River dam will not substantially increase energy reliability or affordability in the Railbelt and may even have the opposite effect.

The proposed dam will increase the Railbelt consumers' energy bill, at least in the short-term.

State of Alaska financing to find and develop its Cook Inlet gas resource could be as little as 50% of the required investment in the hydropower dam, but will provide four times the energy as a Susitna River hydropower dam, at less than one-half the price per million British thermal units.

State-financed and -produced Cook Inlet natural gas resource promises to confer the greatest direct benefit and most benefits to the Railbelt economy of all energy-supply options.

Therefore, state financing, development, ownership, and operation of new Cook Inlet gas fields appears to be the most cost-effective and most secure of the energy-supply alternatives, with significantly less environmental impact than a Susitna River dam.

I. RATIONALE

1. Renewable-Energy Goal

In 2010 the legislature passed HB 306 stating, "it is the intent of the legislature that the state receive 50 percent of its electric generation from renewable and alternative energy sources by 2025."[6]

Alaska Energy Authority's (AEA) justification for its recommendation to build Susitna River dam is that the "only way to achieve this goal [50% of electric generation from renewables by 2025] is for a new large hydroelectric project to be built in the Railbelt region,"[*] and the only type of hydropower project that can provide the required amount of electricity by 2025 is one with a large dam.[7]

2. Railbelt Electrical Generation

Statewide annual *net* electric generation is about 6,500 gigawatt hours (2007).[+]

Utility, industry, and military power plants in the Railbelt generate about 5,500 gigawatt hours, 85% of the state total.[8]

Approximately 4,500 gigawatt hours is generated in the Southcentral, mainly Anchorage, and about 1,000 gigawatt hours is generated in the Fairbanks area.[*+] [9]

Excluding stand-alone industry and military power plants, Railbelt utility-owned power plants produce about 4,700 gigawatt hours annually, about 90% of the Railbelt total net generation.[10]

---

[*] The "Railbelt" is so-called because it encompasses the area served by the Alaska Railroad, which is comprised of two major regions Southcentral (Matanuska-Susitna Valley, Anchorage Bowl and the Kenai Peninsula), and Interior (Fairbanks). Electrically, a single transmission line from the Kenai Peninsula through Anchorage to Fairbanks interconnects the Railbelt.

[+] Net generation is the amount of electricity generated by a power plant that is transmitted and distributed for consumer use; net generation excludes the electricity used by the generating facility to operate auxiliary equipment, such as pumps, motors, and pollution control devices.

[*+] Golden Valley Electric Association (Fairbanks) does not generate all the electricity it distributes. Historically, it has purchased about 300 gigawatt hours annually from Southcentral utilities (Chugach Electric Association, and Municipal Power & Light) and gets about 49,000 Mwh annually from the Bradley Lake hydropower project (near Homer on the Kenai Peninsula).

In Southcentral, approximately 75% of the electricity is generated from burning natural gas, 15% from hydro, 7.5% from coal and 7.5% from petroleum.

In the Interior, approximately 45% of electricity is generated from burning coal and approximately 55% from burning petroleum.[11]

3. Susitna River Dam Generation

The hydropower dam would have an installed capacity of 600 MW, with an estimated 50% annual capacity factor; in other words, the amount of electricity that will be generated would equal the annual output of a 300 MW generator running at full capacity 24/7.

The dam would generate 2,600 – 2,800 gigawatt hours annually – almost 50% of the Railbelt's current net annual electric generation – or 55% of the electricity generated by Railbelt electric utilities (excluding industrial and military power plants).[*]

The project would generate 50% of its annual energy from mid-May through September, supplying approximately 65% of the Railbelt utility demand during that period, and about 43 % of the utility demand from October through mid-May.[12]

However, by 2045, electricity from the dam will supply approximately 40% of the forecasted utility demand, and only 35% of the demand forecast for 2060.[13]

4. Project Description

Susitna River dam would be 184 miles from the river's mouth at Cook Inlet. As currently conceived, the dam is engineered as a 700-foot or 750-foot-high, rock-filled embankment or roller-compacted concrete structure, creating a reservoir about 40-miles long and 2 miles wide, of approximately 20,000 surface acres.

The estimated cost to construct the project is $4.5 billion (2010$).[+] This cost does not include the necessary upgrade to the transmission system, which is expected to be

---

[*] The estimate of annual energy generation is based on the amount of water that will be available for generation over the life of the project, which depends upon 1) the amount of water necessary to maintain minimum flows for aquatic and terrestrial resources downstream of the project and 2) the amount of water draining into the upper Susitna watershed.

[+] According to AEA, this is a "Level IV" feasibility engineering estimate with a confidence range of -15% to -30% or +20% to +50%, meaning the cost could be anywhere from $3.5 billion to $6.5 billion.

several hundred million dollars. This project is too expensive to be privately financed and would be entirely financed by the State of Alaska – half by grant and half by bonds.

5. Case for the Dam

Underlying the legislature's "50%-by-2025" goal and AEA's decision to build a Susitna River dam is the uncertainty about future natural gas supply — where it will come from and its price.[14] Natural gas is the energy-source for virtually all electric power and space heating in the Railbelt with the exception of the Fairbanks area.

Railbelt electric and gas utilities require about 70 Bcf (billion cubic feet) of natural gas annually to meet demand for space heating[*] (32 Bcf) and electric power (38 Bcf).

As early as 2014, gas supply from the existing gas fields in the Cook Inlet Basin, which has been Railbelt's only source of natural gas, may not be enough to meet total demand, with the shortfall increasing annually until around 2040, when there will be no gas left in the existing gas fields.

Susitna River dam, if operated as proposed, will offset about 19 Bcf natural gas currently used by utilities for electric-power generation.

Proponents of the dam claim that Susitna River hydropower would increase reliability of the electric-power system, improve energy security, and mitigate natural gas price volatility and escalation,[15] and do so with no significant environmental impacts.

To ascertain whether the Susitna River dam is justified, this analysis examines:

- Current Cook Inlet gas-supply situation.
- Potential sources of natural gas supply to the Railbelt – Cook Inlet Basin, North Slope, imported gas.
- Viability of the various gas-supply options currently under consideration.
- Cost of energy from the likely energy-supply options.
- The optimal path to energy security and affordability including impacts to the Railbelt economy and environment.
- Environmental and economic impacts of likely energy-supply options.

[*] Throughout this analysis, the estimated volume of gas used for space heating includes the gas used for water heating and cooking.

The proposed Susitna River hydropower plant would displace no more than 25% of the natural gas supply (19 Bcf annually) to meet current demand for space heating and electric-power generation, and therefore, natural gas will continue to play the dominant role in the Railbelt electric-power supply portfolio for at least the next 30 years.[*] [16]

Further, the state's decision to license and construct the dam does nothing to mitigate the urgency to find new sources of gas supply, especially because a license from the Federal Energy Regulatory Commission to construct the project is not assured.

[*] It is unlikely that any new coal-fired generation will be built, primarily because of the current limit on mercury emissions, coupled with uncertainty about a future carbon tax or fee.

II. COOK INLET GAS-SUPPLY STATUS

The following points are key to understanding the gas-supply situation.

- The existing gas fields (gas *reserves*) in the Cook Inlet Basin will soon be unable to produce enough gas to meet current demand, and will run dry around 2040.
- Geologists estimate there is plenty of undiscovered gas (gas *resource*) in the basin to meet demand through the next several decades, requiring investment in seismic surveys and drilling to explore and develop new gas fields.
- The state's approach to ensure development of the Cook Inlet gas resource through financial incentives and leasing is *not* working.
- The oil and gas industry does not believe finding and producing the Cook Inlet gas resource is a competitive investment.

1. Natural History of Cook Inlet Gas

The Cook Inlet Basin is a mature petroleum province. The area of gas and oil discoveries in the upper Cook Inlet Basin extends from Kachemak Bay north to the mouth of the Susitna River and includes fields in offshore Cook Inlet, the west shore of Cook Inlet and the western half of the Kenai Peninsula. The entire area covers approximately 4,400 square miles.[17]

The Cook Inlet Basin formed during the Triassic period, more than 200 million years ago. As the floor of the basin gradually subsided due to tectonic forces, it eventually filled with 25,000 feet of sediment, characterized by sand bodies interspersed with shales, and decomposed vegetation, which formed coal seams and vast volumes of methane, with the gas migrating into the porous sands to form the Cook Inlet gas fields.[18]

Movement of the Pacific plate, together with associated movements along geologic faults, caused crumpling of the rock strata in upper Cook Inlet, resulting in a series of large, elongated north-northeast aligned folds of the Tertiary strata, particularly under the waters of the inlet, with the folds further fractured by faults. Oil and gas then migrated upwards and became trapped in sand bodies within the folds, with oil occupying the lower rock strata and gas pooling in the higher strata.[19]

2. Demand for Natural Gas

The folds were the obvious targets for oil explorers in the 1950s through the 1970s.

Union Oil discovered the first major gas field – the Kenai gas field – in 1959 as it prospected for oil. In almost all instances, gas field discovery and development was a by-product of oil exploration and drilling in the basin. Since major oil exploration began in 1955, there have been 11 oil discoveries accompanied by 28 gas discoveries. About 10 Tcf has been produced since 1958.[20]

Through the early 1970s, average annual consumption was 163 Bcf:

- ~70 Bcf – fertilizer production.
- ~64 Bcf – liquefied natural gas (LNG) export.
- ~25 Bcf – powering oil and gas field equipment.[21]
- ~4 Bcf – powering Tesoro Kenai refinery equipment.[22]

During this period, there was minimal demand for natural gas by Railbelt utilities for space heating or electric power. As Southcentral's population grew 170% from 1970 to 2005, annual utility-demand rose to about 70 Bcf.[23] Cook Inlet yearly gas production peaked in the late 1990s through the early 2000s at about 222 Bcf.[24] In 1994, gas fields produced about 311 Bcf was produced – the most ever produced In one year.[25]

The abundant supply of natural gas enabled utilities to procure long-term – up to 20-year – contracts at favorable prices compared to "Lower-48" states' prices.[26] During the past decade, however, as the gas reserves have declined, new contracts usually have been one- or two-year contracts, with prices steadily higher than those paid in the Lower-48.

3. Cook Inlet Gas Fields in Decline

Natural gas from the Cook Inlet Basin is the primary energy source for space heating and power generation in the Railbelt, other than Fairbanks.[*] Enstar Natural Gas Company (Enstar) supplies gas for space heating and Chugach Electric Association (CEA) and Municipal Light & Power (ML&P) are the major electric utilities.

As early as 2000, utilities, local governments, along with the Alaska Department of Natural Resources (DNR) evinced concern about the ability and capacity of the Cook Inlet gas fields and transportation system to meet future demand. Only in the last several years, because of the decline in proven reserves, has there been an effort to find and produce more gas from the existing fields.[27]

---

[*] Since 1998, Fairbanks Natural Gas Company gas has trucked a small amount of LNG from Cook Inlet to Fairbanks, where it is regasified and distributed to homes and businesses connected to the distribution network (463 residential customers, 656 commercial accounts). Fairbanks Natural Gas Co. contracts for Cook Inlet gas are in effect only through mid-2013.

In 2010, Enstar, for the first time ever, no longer had firm contracts for 100 percent of its forecasted needs. In 2014, Enstar will have contracts for only 55 percent of its gas demand.[28]

ML&P, which owns a third of the Beluga gas field, will not have enough supply to meet demand beginning in 2014.[29]

CEA has gas contracts with ConocoPhillips and Marathon to meet power-generation demand through 2013, but will not have enough gas under contract in 2015.[30]

This does not necessarily mean, however, there is not enough gas to meet demand through this decade; rather it reflects the uncertainty about 1) the rate at which more gas can be found and produced from remaining reserves; 2) the ability of gas-field infrastructure to deliver enough gas during periods of high demand; and 3) the amount of gas that will exported from the LNG facility. Consequently, depending upon the aforementioned factors gas supply will not be able to meet demand anywhere from 2014 to 2020, after which supply will decline inexorably, about 8% annually until about 2040, when the existing gas fields will no longer produce any gas.[31]

Status of Gas Reserves

Reserves are those quantities of oil or gas that are anticipated to be commercially recovered from discovered (known) accumulations.[32] Producing the remaining reserves utilizes seismic acquisition and reprocessing, secondary and tertiary recovery techniques, and drilling infill and extension wells.[33]

Between 2001 and 2009, 128 gas wells were drilled, of which 105 were completed and estimated to produce 519 Bcf.[34] Almost all the new wells were onshore on the east side of Cook Inlet in established fields – Ninilchik, Kenai, and Deep Creek. Ninilchik wells surpassed expectation; Kenai wells were average, while Deep Creek wells were marginal.

Based on an engineering methodology known as *material balance analysis*, in 2011, the state Oil and Gas Division estimates that 949 Bcf can be produced from existing wells and estimates another 738 Bcf can be produced with new wells and with additional compression in the existing gas fields, for a reserves total of 1,587 Bcf.[35] About 187 new wells would need to be drilled by 2020 to maintain supply at current demand[36] – 31 million cubic feet per day (MMcf/d) of new production must be added each year. Otherwise, supply will fall short of demand by at least 5.1 Bcf and up to 11.4 Bcf for the year, as early as 2014 or as late as 2020.[37]

Status of Gas-Supply Infrastructure

Ensuring that Cook Inlet gas supply meets demand through the current decade depends not only on finding and producing more gas in the currently operating gas fields as explained above, but also ensuring gas-field infrastructure can deliver gas at the exact time it is needed and in the quantity necessary.

The average daily demand for electric-power generation and space heating is about 35 MMcf/day in the summer, while peak winter demand is 168 MMcf/day. Thus, gas demand during a peak winter day can be 12 times the volume of gas used during a summer day.[38]

The deliverability problem is a result of the depletion of gas reservoirs in the past several years: as the gas reservoirs become depleted, the pressure of the gas within the reservoir drops and water encroachment usually increases. Water encroachment decreases gas flow-rate (and increases water-handling problems at the surface).[39] Pressure drop and water encroachment affect deliverability. [40] A further complication affecting deliverability as gas fields become depleted is that the gas-containing reservoir becomes more prone to damage if it does not produce gas at constant rates; therefore as the existing gas fields become depleted they cannot respond as quickly to match variations in gas usage.[41] The decrease in pressure, water encroachment, and impaired ability to ramp gas volumes up or down jeopardize the delivery of gas during the peak days and peak hours of winter when space heating and electric demand surge due to the combination of darkness and cold temperature.[42]

Adding to concern about deliverability is the uncertain status of the ConocoPhillips LNG plant, located in Kenai. Historically, the LNG operation helped ensure deliverability by diverting gas from the plant to meet peak demand and also by keeping gas wells producing in the low-demand summer season, thereby avoiding the potential difficulties associated with shutting down wells in the summer to restart to meet winter demand. In 2011, the company announced plans to shutter the plant, citing poor market conditions, but a month later tsunami destroyed Japan's Fukushima nuclear reactor and ConocoPhillips continued to export LNG to meet the increase demand there. Nonetheless, with ConocoPhillips' export license expiring in 2013, the uncertainty about the continued operation of the LNG plant closing heightened the urgency of bringing more storage on line.

Until 2012, only 9 Bcf could be stored at Union Oil's Swanson River Field and Pretty Creek facilities and Marathon Oil's storage at the Kenai Gas Field – all together, capable of delivering 90 MMcf/d. The Union Oil storage facilities are designed as peaking facilities for the rapid delivery of gas over a short period of time. The Marathon facilities are used to support base-load deliveries under existing gas-supply contracts. These are proprietary storage reservoirs to satisfy contractual commitments of these producers, and are not available to third parties.[43]

Enstar's Cook Inlet Natural Gas Storage Alaska facility, which was completed in 2012 at a cost of about $180 million in anticipation of the loss of the LNG plant, is available to third parties.[44] Gas is injected into storage during the summer months, when available supply exceeds demand, to be withdrawn during winter peak demand. The facility has a capacity of 15.7 Bcf.[45] The initial storage capacity is 11 Bcf, and can deliver up to 150 MMcf/day.[46]

In addition to increasing available storage, other measures completed or underway to enhance deliverability include increasing compression at the Beluga gas field, which supplies fuel to CEA's Beluga power plant and ML&P, and modifying the piping configuration of the Beluga power plant's gas-inlet unit to accommodate reduced gas pressures.[47] Deliverability will also improve with reduction in demand due to energy-efficiency improvements, which includes new and retrofitted gas-fired power plants that promise to reduce demand about 5 Bcf annually, beginning in 2013.[48]

III. GAS-SUPPLY OPTIONS

Once Cook Inlet gas reserves can longer meet demand, maintaining an adequate supply will depend upon securing gas from other sources. As mentioned above, there are three major options for future gas supply for the Railbelt

- Cook Inlet Basin gas resource.
- North Slope gas reserves.
- Imported gas.

1. Cook Inlet Basin Gas Resource Option

Resources are undiscovered oil and gas accumulations believed to exist based on geologic knowledge and theory. C*onventionally recoverable* resources are resources that could be recoverable using current conventional technology. *Conventional economically recoverable* resources are those resources that could be economically viable at specified price levels.[49]

Resource Estimate

The geology of Cook Inlet indicates a substantial, conventional gas resource remaining to be found and developed.[*] The bulk of the conventional gas resource is believed to be located in stratigraphic traps, which exist throughout the entire upper Cook Inlet sub-basin.[50] Most of the gas that has been discovered thus far in Cook Inlet has been found at depths of 3,000 to 5,000 feet sub-sea, and undiscovered gas is likely to be found at similar depth.[51]

In fact, "field-distribution analysis" suggests there is a substantial amount of undiscovered gas in the basin. This analysis uses information about the size and number of discovered gas fields in a basin to estimate the total resource. According to accepted geologic theory and evidence, the number of gas fields and the size of those fields in a basin should be log-normally distributed. Cook Inlet is unusual in that the distribution of gas discoveries does not fit the usual pattern, termed a *log-normal distribution*. Put simply, there should be a large number of small fields, a smaller number of medium sized fields, and a few large fields within a given basin.

[*] "Conventional" gas is so-called to distinguish it from "unconventional," such as coal bed methane and shale gas.

In Cook Inlet, many of the large fields and some of the expected medium fields have been discovered, but numerous small fields have not been discovered.[52] There are undiscovered fields with 200 to 1,500 Bcf OGIP (Original-Gas-in-Place[*]) missing from the expected field-size distribution.

Based on what is known about field distribution, the conventionally recoverable resource has been estimated at about 10 to 14 Tcf. [53] More recently, USGS has increased the estimate to 15 Tcf.[+] [54] A more conservative estimate of conventionally recoverable resource, based only on undiscovered class 6, 7, and 8 gas fields, is 7.8 to 10.2 Tcf.[55]

Nonetheless, large portions of the area open to exploration and development in Cook Inlet have yet to be adequately evaluated for the stratigraphic-style trapping mechanisms in which gas should have accumulated.

Finding the Gas Resource?

Geologists believe that the gas is dry gas not associated with oil, and should be found in stratigraphic traps in off-structure positions. 3D seismic acquisition and extended reach horizontal drilling provide the methods and opportunities to find and develop these reservoirs much more efficiently.[56] 3D seismic acquisition coupled with extended-reach horizontal drilling permit the identification of more subtle stratigraphic traps and then the drilling technology can minimize impacts while accessing these traps, which may be located in the environmentally sensitive, near-shore zone or beneath critical habitat.[57]

Most of the gas resource appears to be located in offshore, upper Cook Inlet, all of which belongs to the State of Alaska and is made available to oil and gas companies through the state lease program, administered by the Department of Natural Resources.

Despite the declining reserves and despite the estimate of a large gas resource in the Cook Inlet basin, none of the major Cook Inlet producers – ConocoPhillips, Marathon Oil, and Chevron have explored for the resource, drilling only new wells in their established gas fields as necessary to meet existing contract obligations.[*+] [58]

---

[*] OGIP means "original gas in place" – the total amount of gas prior to production.

[+] USGS also estimates there is about 5 Tcf of unconventional gas resources in coal beds or very tight gas-sand plays.

[*+] During the past few years, Hilcorp Energy acquired Chevron's Cook Inlet assets and its purchase of Marathon's assets is awaiting approval from regulators, which is anticipated to occur in 2013; Hilcorp will then own 70% of the proven Cook Inlet gas reserves.

Exploration by the smaller oil and gas companies has been targeting oil, not gas, albeit some companies are looking for gas in established fields that are mostly onshore, with some exploration for nonconventional gas, also onshore. Apache Oil has begun a 3-D-seismic-survey for oil in western Cook Inlet.[59] When Furie Oil drilled in the Corsair prospect exploring for oil in the offshore Kitchen Lights Unit in 2011, it was the first time since 1993 that an offshore exploration well had been drilled. That prospect had been previously drilled four times by Shell, Arco, and Phillips for oil, beginning in 1962.[60] Although all the wells, including Furie's, had gas shows, there was not enough oil to justify further investment.[61] Given that the gas in Cook Inlet is not associated with oil, it is not realistic, however, to expect that current oil exploration will find much gas.[62]

Industry Investment Calculus

The reason there has been no exploration for gas offshore is because it is not sufficiently profitable.[63] Marathon Oil has explained that "the project economics and market uncertainties make it difficult for projects to compete effectively for finite money. Alaska projects are not considered solely on their absolute merits. They are compared on a relative scale in comparison to other worldwide opportunities in which companies such as Marathon may invest."[64] The Regulatory Commission of Alaska (RCA) has acknowledged that "investment capital in Cook Inlet must compete with investment opportunities worldwide [and] risk associated with exploration must be compensated or exploration will go elsewhere."[65]

There are two major factors that militate against investing in the Cook Inlet gas resource:

- The Railbelt is simply too small a market to produce a sufficient rate of return on capital investment in the Cook Inlet gas resource.*

- Even if ConocoPhillips were to continue to operate its LNG export facility after 2013, it is highly problematic that the increased demand from Pacific Rim markets is sufficient reason for investors to find and produce the Cook Inlet resource, given the increasing competition among existing and pending LNG suppliers.

Even if gas is discovered when exploring for oil, it is unlikely that the gas will be developed and produced if no oil were to be discovered or if the oil find is too small to be profitable. Even though Furie claims to have found a significant amount of natural gas when drilling the Corsair prospect in the Kitchen Lights lease, it still has not decided whether investment in production wells and other infrastructure is justified.[66]

---

* A rule-of-thumb used to ascertain the feasibility of investment in the oil and gas industry is a four year payback of the investment. Even if the entire 70 Bcf annual demand were to be supplied from new gas fields, the payback period would probably still be too long to justify the investment.

State Leasing Program

Oil and gas companies gain access to offshore upper Cook Inlet by acquiring leases from the State of Alaska. The state's leasing program requires only that the lease holder, upon finding gas, shall develop and produce the gas if it can be done so at a "reasonable profit" to the operator.[67] The problem is that the lease does not define "reasonable profit." This definition of "reasonable profit" has long been a point of contention between the State of Alaska and North Slope operators, and may become one in Cook Inlet.[68]

If the lessee does not believe a reasonable profit can be obtained for produced gas, the gas will not be developed. Even more of an impediment to developing the resource is that the state's standard lease does *not* require the lessee explore for gas or oil. The lessee can hold the lease for the standard term of 7 or 10 years *without* performing any exploration, so long as lease payments are made on schedule. All recent leases in Cook Inlet (other than the few in the Cosmopolitan Unit) require *only* that the leaseholders make their lease-rental payments: there is no stipulation that the lessees shall explore for gas or oil.[+] [69]

Yet, the Department of Natural Resources has testified that

> . . . interest in natural gas exploration, production, and storage in Alaska's Cook Inlet is growing, thanks to efforts by the state to encourage exploration and drilling while remaining sensitive to the needs of industry to be able to respond to fluctuating energy demand in this still very vibrant resource area. Together, the state and industry have shown detractors that Alaska remains open for business, and the ill-informed statement that "Southcentral Alaska is facing an inevitable shortage of natural gas" will be proven wrong.[70]

This statement might be accurate with respect to finding and producing remaining reserves in existing gas fields, but is not at all accurate with respect to finding and developing the Cook Inlet Basin gas resource. DNR is optimistic that private capital will develop gas resource because:

- The 2010 Cook Inlet lease-sale garnered 37 bids compared to only 5 bids from the 2009 Cook Inlet lease-sale.[71]
- The legislature enacting a tax credit for the first three unaffiliated wells using a jack-up drilling rig to explore for gas *or* oil.[+] [72]
- Tax credits are available pursuant Alaska's Clear and Equitable Share.[73]

[+] It can take several years to bring a field into production.

[+] The legislation caps the credit at a total of $67,500,000 and may not include the cost to construct or manufacture a jack-up rig and must be for work performed after June 30, 2010.

- In 2011, the Cook Inlet lease-sale garnered 110 bids.[74]
- In September 2011, Escopeta (now Furie) drilled in offshore Cook Inlet with a jack-up rig.[75]
- Buccaneer announced it would bring a jack-up rig to Cook Inlet in 2012.[76]
- In November 2011, Furie struck gas in the Corsair prospect of the Kitchen Lights unit.[77]

Taken together, the 2011 lease sales in offshore Cook Inlet, one jack-up rig drilling in Cook Inlet and another on its way, along with the Furie gas find, make DNR's forecast of a Cook Inlet gas renaissance appear credible,[78] but, in this case, appearances are deceiving:

- The claim that the state's tax credit incentivized Escopeta's (now Furie Oil) acquisition of the jack-up rig is confounded by the fact that Escopeta would have lost its lease if it did not begin drilling in 2011.[79]
- Most of the 2011 leases were acquired by Apache Oil for the oil, not gas, potential; the other leases were acquired by individuals, none of whom possess a jack-up drilling rig, therefore, they lack the ability to explore for oil or gas offshore.[80]
- Buccaneer has stated that it will use the jack-up rig to explore for oil.[81]
- Furie is exploring for oil in the Corsair prospect, not gas, and it is not unexpected that it would find gas as it drilled for oil, since, all the previous exploratory oil wells in the prospect showed gas.[82]

Since 2000, the state has known that Cook Inlet gas reserves were running out; the state also knew the oil and gas industry interpretation of "reasonable profit" has impeded development of North Slope gas on the state leases;[*] and the state is fully aware that the significant investment in Cook Inlet gas has been in new wells in established gas fields. Despite that knowledge, the state's recent Cook Inlet leases have not been structured to either compel exploration for the gas resource or to lease just the oil and not the gas. Instead, the state-leasing program allows the lessees to prevent development of the Cook Inlet gas resource.

Even for those leases comprising a cooperative or unit agreement, which requires require drilling and production, the only recourse the state has to non-performance is to declare the lease in default. The leaseholder has the right to appeal and if the appeal is not successful, the lessee may then litigate. In the meantime, on-site work usually halts, and in the event the default is sustained and the lease reverts to the state, the state must re-lease the acreage, further delaying exploration and development.

---

[*] Notably the Pt. Thompson lease.

Having enacted tax credits that make Cook Inlet one of the most favorable tax and royalty environment in the United States,[83] the legislature had hoped to provide sufficient incentive to catalyze exploration and development for natural gas by lessees, but that strategy has not borne fruit. Cook Inlet may be an expensive place to explore, but the expense of exploration is but one of many factors that come into play in investment decisions.[84]

Consequently, the legislature is not so confident that the leasing program will result in private investment in the Cook Inlet gas resource, [85] which is why it has authorized a feasibility study of the so-called "bullet-line" from the North Slope to Southcentral Alaska (see below). Nonetheless, despite the legislature's cynicism, DNR officials continue to insist on the efficacy of the leasing program.[86] Unfortunately given the small Railbelt market (and the uncertainty about export sales), the cost of developing the gas resource is too high to justify private investment.

Gas-Resource Development Costs

The cost of production of gas from new gas fields delivered to the Cook Inlet pipeline system includes cost of exploration, development, operations, transportation (between the well head and the extant pipelines), and storage.

Exploration

Exploration costs include geological and geophysical expenses, lease acquisition and bonus, lease rentals, seismic studies, and drilling costs.

- Seismic costs per square mile for 3-D acquisition and processing for offshore Cook Inlet, onshore, and the inter-tidal transition zone are estimated to be $45,000/sq mile, $85,000 to $90,000/sq mile, and $110,000 to $115,000/sq mile, respectively (2004$).[87]
- Exploration wells are estimated to cost from $10 to $20 million, depending on location, well trajectory, depth, and target.[88] Two years ago, Escopeta stated the day-rate of its jack-up rig lease will be "much less than $100,000."[89]

Development

Development costs are primarily costs associated with drilling production wells.

- The 2004 South Central Natural Gas Study estimates development wells to cost from $3.9 million for a straight well to $7.5 million for a horizontal or extended reach well.[90]
- A 2010 utility-commissioned study estimated the cost to drill 128 gas wells in Cook Inlet between 2001 and 2009 from $1.0 - $1.2 billion. These wells are estimated to

produce 563 Bcf for a capital cost of $1.78 - $2.06/Mcf (thousand cubic feet*). The study forecasts capital costs of between $2.50 - $4.30/Mcf for wells drilled between 2010 and 2019.[91]

- The published cost for the recent Osprey platform at the Redoubt Shoal field is $30 million, excluding drilling and production facilities. That project uses a multi-phase pipeline to deliver produced fluids to shore for further separation and processing for an additional $80 million.[92]
- Gas-handling facilities' costs are related to processing capacity and are estimated to be $0.025/MMcf/d for peak throughput capacity.[93]

Operations

Operating expenses in Cook Inlet are considered proprietary. In the absence of reported information from Cook Inlet producers, the 2004 study could only estimate costs based on available industry data.[94] Variable operating costs can be divided into direct operating cost per Mcf and the cost to dispose of produced water:

- Fixed operating costs were estimated to be $1,500/well/month.[95]
- U.S. Department of Energy data for direct operating-costs in the Rocky Mountain region for 8,000-foot well depth is assumed to be representative for (onshore) Cook Inlet operating conditions because of similar winter conditions and well depths.[96] From flow rates of 5,000 Mcf/day to 20,000 Mcf/day, the variable operating costs range from approximately $0.01/Mcf to $0.015/Mcf.[97]
- No hard data were found in the public domain for water disposal costs, which vary by field due to differences in the overall level of water production, water handling capacity, and available disposal options. Water disposal costs were estimated to be $2/bbl (2003$) — an algorithm was developed to estimate water production as a function of percent of estimated ultimate recovery, with a sharp increase in water production per Mcf as a field nears depletion.[98]

Storage

In July 2010, Cook Inlet Natural Gas Storage Alaska, LLC filed an application of public convenience and necessity with the Regulatory Commission of Alaska to construct and operate its proposed Kenai storage facility.[99] In January 2011, RCA determined the tariff for gas stored and supplied from the facility.[100] The tariff is about $0.11/Mcf on average for gas stored in the facility.[101]

Transportation

The pipeline tariff allows for capital recovery at the regulatory rate of return plus cost recovery for operating cost, ad valorem taxes, depreciation, a dismantlement charge,

* One Mcf releases about 1 million Btu (mmBtu) during combustion.

and state and federal income taxes. The tariff charge per Mcf can vary depending on the transported volumes of gas, with larger volumes resulting in lower tariffs.[102]

Gas delivered to Southcentral/Railbelt utilities is transported by a pipeline system comprised of five separate pipelines, each with its own tariff, as explained in the table below:[103]

Pipeline	Type	Operator	Tariff
Kenai Kachemak Pipeline	**Common Carrier**	**Marathon**	**$6.4408/Mcf/month $4.1047/Mcf/month $117.5077/Mcf/month (depending on zone)**
Kenai Nikiski Pipeline	**Common Carrier**	**Marathon**	**$0.2029/Mcf**
Cook Inlet Gas Gathering System	**Common Carrier**	**Marathon**	**$0.2378/Mcf**
Beluga Pipeline	**Common Carrier**	**Marathon**	**$0.25/Mcf**
Enstar	**Public Utility**	**Semco**	**$0.07 -$0.17/Mcf (depending on volume)**

If additional pipeline were required to serve new gas fields, there will be a tariff for gas transported through that pipeline, based on the cost of the pipeline.*

Gas-Resource Development Cost

The comprehensive 2004 Cook Inlet gas study is the only publicly available estimate of the cost of bringing the gas resource into production: [104]

- $152 million for a Class 6 field.
- $251 million for a Class 7 field.
- $384 million for a Class 8 field.
- $5 to $6 billion to develop 6.5- 8.5 Tcf (50% of the estimated 13 to 17 Tcf remaining undiscovered reserves in the Cook Inlet).

* For instance, the onshore 33-mile-long, 12-inch diameter Kenai-Kachemak pipeline (KKPL), which entered service September 2003, cost about $25 million.

In light of recent reports on costs of new producing wells in the existing Cook Inlet gas fields, the 2004 estimate of $5 to $6 billion to develop the 7.5 Tcf Cook Inlet resource is probably too low, because the capital costs for wells in new gas fields will be at least equal to the capital costs of new wells in existing reserves. Assuming a wellhead cost of $2.40/Mcf and about $0.15/Mcf for piping from the well to the existing pipeline system, the estimated capital cost to find and develop the Cook Inlet gas resource is $2.55/Mcf, or about $18 billion to find and develop 7.5 Tcf of the Cook Inlet gas resource.

Assuming a $3.6 billion dollar investment to find and develop about 1.5 Tcf of gas resource, which would provide a 20-year supply to Southcentral at current demand and assuming a 4-year payback on investment, the price of gas delivered to Southcentral pipeline system would be $13.00/Mcf.[*]

Currently, gas produced from Buccaneer's new wells in the existing Kenai Loop gas field has a $10.00/Mcf ceiling price (cost delivered to Southcentral pipeline system), a floor of $5.75/Mcf, and a weighted average cost of $5.89/Mcf (2012$) escalating to $6.16/Mcf in 2014.[105]

2. North Slope Gas Options

North Slope gas reserves are estimate to be about 35 Tcf.

There are various proposals to pipe North Slope gas to the Railbelt, including two "bullet" lines from North Slope to Fairbanks and Southcentral; a North Slope to Valdez pipeline, with a spur to Southcentral; a North Slope-Fairbanks pipeline to an LNG plant, with LNG then transported by rail to Southcentral, and two proposals to truck LNG from the North Slope to Fairbanks and possibly to Southcentral.[+]

The cost of gas from these various North Slope supply options varies, with the major variable being the pipeline tariff. For most of the supply alternatives discussed in this section, the estimates of the cost of gas delivered to Southcentral and Interior/Fairbanks depend upon the following assumptions:

- Cost/Mcf is levelized with no inflation from 2011$.

---

[*] Presumably, this price cannot be higher that the most likely alternative source of supply, which is imported gas. This price assumes that gas will be sold only into the Railbelt market, if the gas were sold to other markets, presumably as LNG, then the price would presumably be less due to greater revenue stream.

[+] Due to the increased production of shale gas in Canada and the lower 48, a North Slope-to-Canada pipeline is no longer in the cards.

- Wellhead price of North Slope natural gas is $2.00/Mcf.[*]
- Cost is at the point of entry to the regional pipeline system.
- Price of gas to the utility is the cost of gas delivered to the local pipeline system plus the pipeline tariffs and storage tariffs.
- Costs of financing, royalties, taxes, inflation, or operation and maintenance are not included.[+]
- No potential carbon tax or fee is included.

North Slope to Railbelt Pipelines

The Alaska Gasline Development Corporation (AGDC) proposes the Alaska-Stand-Alone-Pipeline and the Fairbanks Gas Co proposes the Arctic Fox Pipeline. TransCanada has abandoned its proposed Alaska-to-Canada gas line due to declining North American gas prices and is now considering a pipeline to a Southcentral LNG-export terminal.

Alaska-Stand-Alone-Gas-Pipeline

The proposed project calls for a 737-mile-long, 24-inch-diameter pipeline from the North Slope to Southcentral, with a 35-mile-long, 12-inch-diameter lateral line to Fairbanks. Total estimated project cost is $7.52 billion ($2011).[*+] The project could be operating by 2019.[106]

The legislature authorized AGDC to study the feasibility of the pipeline because it does not share the executive branch's (DNR) optimism about private sector development of an in-state gas supply, having determined that the "citizens have a need for natural gas that *will not be met by the private sector* and that it is unacceptable for those citizens to be without natural gas (emphasis added)."[107]

The 24-inch-diameter pipeline can carry up to 500 MMcf/d (million standard cubic feet per day); the lateral line to Fairbanks has a 60 MMcf/d capacity.[108] However, as the current demand for gas in Southcentral is about 165 MMcf/d (89 MMcf/d for electric power, 76 for MMcf/d for space heating), and Fairbanks to use about 47 MMcf/d if it were to convert space heating and electric power to natural gas,[**] additional customers

---

[*] With the steady decline in Henry Hub price, the estimate of $2.00/Mcf for North Slope gas at the wellhead may be too high.

[+] Royalties and severance taxes are paid by the gas producers.

[*+] Uncertainty range of ±30%.

[**] In 2012, Fairbanks North Star Borough established the Interior Alaska Natural Gas Distribution Utility to develop the pipeline- distribution infrastructure.

will be necessary, because the pipeline must operate at near 100% capacity to be financially viable. AGDC expects that 240 MMcf/d could be exported as LNG and another 30 MMcf/d might be sold to mines in Western Alaska, assuming the mines are developed.[109]

AGDC has also determined the North Slope gas producers are not willing to develop the bullet line, because the investment risk/reward ratio is unsatisfactory. AGDC concludes the state would have to finance the project.[110] If $7.5 billion is financed through bonding, the debt financing would add about $4.5 billion to the project for a total cost about $12 billion.[111]

The estimated cost delivered to Southcentral is $9.75/Mcf (wellhead gas at $2.00/Mcf, gas conditioning at $2.04/Mcf, pipeline tariff at $5.71/Mcf); while the estimated cost delivered to Fairbanks is $10.99/Mcf (wellhead gas at $2.00/Mcf, gas conditioning at $2.04/Mcf, pipeline tariff at $6.95/Mcf).[112]

Fairbanks Pipeline Co.

The Fairbanks Pipeline Company, which operates the second largest crude oil pipeline system in the state, proposes the "Arctic Fox" project to bring North Slope gas to Fairbanks with the option to service Southcentral.

The "base case" is a 514-mile-long, 12-inch-diameter pipeline from Prudhoe Bay to North Pole, 14 miles east of Fairbanks. The company plans on purchasing treated and compressed gas from Prudhoe Bay producers. The pipeline would initially carry 19 Bcf annually with the capacity for another 4 Bcf without additional compression. An additional compressor station would allow the pipeline to carry more volume.[113]

The estimated capital cost of the North Slope to North Pole segment of Arctic Fox is $723 million (2010$).[114] The estimated cost of the treated and compressed gas is $4.22/Mcf,[*] [115] the tariff to deliver to the Fairbanks area is estimated to be $5.44/Mcf,[116] for a total of $9.66/Mcf (2010$) delivered to Fairbanks,[+] which is about 30% of the cost of fuel oil and about 25% the cost of propane used in Fairbanks for space heating.

Arctic Fox could also bring gas to Southcentral, which would require an 18-inch-diameter pipeline from the North Slope to Southcentral and would be routed to the west of Fairbanks. At Livengood, northwest of Fairbanks, there would be a 90-mile-long,

---

[*] The total gas-purchase price of $4.22/Mcf is $2.00/Mcf wellhead price plus $2.22/Mcf price for gas treatment and compression.

[+] In this supply option, $9.66/Mcf delivered to Fairbanks includes financing, operations, and maintenance.

12-inch-diameter extension to North Pole to serve the Fairbanks area. From Prudhoe Bay to the Livengood Hub the pipeline could carry up to 286 MMcf/d (91 Bcf annually), the 12-inch line could carry up to 100 MMcf/d (36 Bcf annually) to the Fairbanks service area.

If the decision were made to serve Fairbanks and Southcentral, the 18-inch-diameter pipeline segment from the North Slope would be built first. The cost of the North Slope to Livengood pipeline with the extension to Fairbanks would be $248 million (2010$) more than the base-case North Slope to North Pole pipeline, for a total capital investment of about $1 billion (2010$).[117] The increased capital investment for the 18-inch-diameter segment would increase the cost of service to Fairbanks to $9.02/Mcf, for a total delivered cost of $13.24/Mcf, until the pipeline to Southcentral were constructed when gas in Southcentral averages $8.27/Mcf.[*][118] The cost of extending the pipeline to Southcentral is estimated to be another $1.1 billion (2010$).[119]

With the entire pipeline system in service, the cost of gas (2010$) delivered to Fairbanks would fall to $9.66/Mcf; cost of gas delivered to Southcentral would be $8.27/Mcf.[120]

TransCanada

Under preliminary consideration is an 800-mile-long, 48-inch-diameter pipeline from the North Slope to an unspecified port in Southcentral, where gas would be liquefied and exported. The project is estimated to cost from $45 billion to $65 billion.[121] The cost of gas delivered to Southcentral would probably be less than $8.00/Mcf.

North Slope to Valdez Pipeline

This project – the so-called "All-Alaska" pipeline – is proposed to be a 745-mile-long, 48-inch-diameter pipeline from the North Slope to Valdez with a 150-mile-long, 24-inch-diameter lateral pipeline from Glennallen to Palmer. The gas would be liquefied at Valdez and then exported. The main pipeline is estimated to cost $22.3 billion (2010$).[122] The LNG facility is estimated to cost about $25 billion.[123] The spur line is estimated to cost $750 million.[124] The mainline is a project of Alaska Gasline Port Authority.[+][125]

---

[*] Fairbanks Pipeline Company estimates it could deliver gas to Southcentral at $8.27/Mcf. Therefore, when the cost of gas delivered to Southcentral climbs above $8.27/Mcf, the company anticipates it could construct the 18-inch-diameter pipeline segment from Livengood to Southcentral.

[+] The spur line would have been a project of the now-defunct Alaska Natural Gas Development Authority; it is not clear what entity, if any, would construct the spur line if the main line were to be built.

The estimated tariff for gas shipped in the main line from the North Slope to Glennallen is $1.50/Mcf, and the estimated tariff from Glennallen to Palmer (Southcentral) is $1.75/Mcf.[126] Assuming gas-conditioning charge of $1.20 - $1.50/Mcf; wellhead gas price of $2.00/Mcf, the cost of gas delivered to Southcentral would be between $6.45 - $6.75/Mcf.

North-Slope LNG to Fairbanks

There are two proposals to truck LNG from the North Slope to Fairbanks, where it would be regasified.[*] These proposals would require a new LNG facility.

Golden Valley Electric/Flint Hills

In September 2012, Golden Valley Electric Association (GVEA) announced a 20-year contract with BP to purchase up to 23 Bcf annually. GVEA would produce LNG and truck the LNG to Fairbanks along the Dalton Highway. The LNG would re be regasified and used at GVEA's North Pole power plant, and Flint Hills Resources would use some gas as supply fuel for crude oil refining operations at its North Pole refinery.[127]

Capital cost is estimated at $186 million (2012$), including the LNG plant, 40 trucks, storage, and a regasification facility to produce between 8 and 9.5 Bcf annually.[128]

GVEA estimates the cost of delivered gas at $14.00/Mcf.[129]

Fairbanks Natural Gas LLC

Fairbanks Natural Gas also proposes to truck North Slope LNG to Fairbanks. Several years ago, Polar LNG, an affiliate of Fairbanks Natural Gas, contracted with ExxonMobil to buy its North Slope gas. In 2009, Fairbanks Natural Gas leased state land near Prudhoe Bay for its LNG plant, but the plant has yet to be built. Since GVEA and Flint Hills are now pursuing their own trucked-LNG project, Fairbanks Natural Gas may have lost two potential major customers, making its proposal more problematic.[130]

Fairbanks Natural Gas estimate of the cost of LNG delivered to Fairbanks is $12/Mcf.[131]

3. Imported Gas Option

Ironically, imported gas, either liquefied natural gas (LNG) or compressed gas, is likely to be the only supply option if neither North Slope gas reserves nor the Cook Inlet gas resource were to be available as Cook Inlet reserves fall short of demand.

---

[*] Trucking LNG from the North Slope to Southcentral is not feasible.

Apparently, imported compressed natural gas would be less expensive than imported LNG, but there are no vessels available to deliver compressed gas to Alaska.[132] Therefore, for the purpose of this analysis the imported gas option is LNG; Southcentral utilities have been negotiating with potential LNG suppliers 2011 to supply between 5 Bcf and 12 Bcf as early as 2014.[133]

Receiving and Regasification Infrastructure

LNG will require regasification. The regasification options are reconfiguration of the ConocoPhillips Kenai plant, a new onshore or near-shore, stand-alone facility, and shipboard regasification.

Shipboard regasification, where the regasification system is onboard a vessel, usually takes less time for the gas importer to implement than a stand-alone regasification plant, which is typically located onshore, but can also be constructed near-shore, depending on the site. Nonetheless, shipboard regasification requires that some receiving infrastructure be constructed, including moorings, pipelines, wharfs and storage. Although the construction costs are less than building an onshore/near-shore regasification facility, when the costs of chartering the vessels are included, the total annual expense may be more than a conventional onshore facility. Further, weather and other ocean conditions can limit the reliability of shipboard regasification.[134] Shipboard regasification seems best suited for markets that require only small volumes and/or an intermittent supply of LNG.

Regardless of whether onshore/near-shore or shipboard regasification system is deployed, LNG supplied to Southcentral will probably require even more gas storage for ensuring gas deliverability during winter-peak demand as well as for ensuring security of supply in the event of a disruption in the LNG supply-chain. The Cook Inlet pipeline system may also have to be modified and expanded as the gas-import volume increases.[135]

Cost of Imported LNG

The cost of LNG delivered to Southcentral includes the purchase price of imported LNG and the cost of regasification.

LNG-Contract Pricing

The report on LNG prepared for the Alaska Gasline Development Corporation estimates that Southcentral utilities can expect to pay about $13.50/Mcf for imported LNG, which includes shipping to Alaska and which is based on a WTI per barrel oil price of $80.[*] [136]

---

[*] WTI stands for West Texas Intermediate oil, the price of which is the industry benchmark.

The report on LNG prepared for Alaska Gasline Port Authority prices imported LNG at $10.34, assuming a WTI price of $75.00.[137]
The divergence in cost estimates between the two reports is due to different estimation formulas as well as the difference in capital costs of different LNG plants, which affects the LNG cost of production and hence pricing. Further, in the event of an oversupply of LNG – due to increased supply of conventional and non-conventional gas supplies, and or increased LNG capacity/production – there will be downward pressure on pricing. Moreover, at least one analyst believes LNG prices may fall because some gas producers can sell the methane (gas) at negative value because of the high NGL content of the natural gas production.[138]

Regasification Cost

In addition to the LNG price delivered to the LNG plant, there is a tolling fee for regasification.[139] The tolling fee is based upon the cost of the LNG receiving and regasification facility, and is essentially a tariff.[140] Shipboard regasification can range between $50-200 million.[141] Reconfiguring the existing LNG export plant into a receiving and regasification plant is estimated between $62.5 million [142] to $150 million.[143] New, onshore regasification plant is estimated to cost up to $400 million.[144] Depending upon capital cost of the regasification system, AGDC estimates the tolling fee between $0.24 to $0.56/Mcf.[*]

The cost of LNG delivered to Southcentral would be somewhere between $11.00 - $14.00/Mcf, assuming a WTI of $80.00.

[*] If new pipeline were necessary for delivering the regasified gas and if additional storage for the regasified gas is necessary for deliverability, those tariffs would be additional costs.

4. Delivered Cost of Gas-Supply Alternatives

Gas-Supply Option	Cost/Mcf Southcentral[*]	Cost/Mcf Fairbanks[+]
Cook Inlet Resource	$11.00 - $14.00	N.A.?[*+]
Alaska-Stand-Alone-Pipeline[**]	$9.75	$10.99
Fairbanks Pipeline Co. 12” North Slope to Fairbanks 18” North Slope to Fairbanks 18” North Slope to Fairbanks & Cook Inlet	 N.A. N.A. $8.27	 9.66 13.24 $9.66.
All-Alaska Pipeline[++]	$6.45 - $6.75	NA
North Slope LNG to Fairbanks	N.A.	$14.00
Imported LNG	$11.00-$14.00[**+]	N.A.

[*] Delivered cost to point of entry of Southcentral pipeline system.

[+] Delivered cost to point of entry of Fairbanks distribution system.

[*+] It would be possible to build a pipeline to Fairbanks to supply Fairbanks with Cook Inlet gas, or to continue to sell gas-fired electricity to Fairbanks.

[**] The delivered cost assumes the pipeline is at full capacity; otherwise the tariff would be greater.

[++] The delivered cost assumes the pipeline is at full capacity; otherwise the tariff would be greater.

[**+] Depending on the tolling fee, this could be as much as $1.50 more (see below).

5. Viability of Gas-Supply Options

None of the North Slope gas-supply options discussed above has gone beyond the feasibility-study stage. Consequently, the gas-supply option that is eventually implemented is not readily discernable. Still there is sufficient information to infer which supply options may be the more viable investments, or, conversely, to ascertain the options that do not seem to pencil out based on currently available information.

Financial feasibility depends upon the amount of time necessary to payback the investment and rate-of-return.[*] Project financing is based upon complex contracts typically involving many parties, including suppliers, buyers, and financiers. Integral to project financing is assessment of major risks, including construction time, operational costs, supply reliability, off-take volume, price.

Depending upon which options are financially feasible, they can be compared with respect to security, permitting, and environmental impact (see Section VI).

Cook Inlet Resource

The risk of exploration is that the cost is higher than anticipated and the amount of gas is less than anticipated. While no one company is likely to undertake the exploration and development of all potential fields, any investor must be assured of markets for the gas at a rate of return at least equal to other investment opportunities in oil and gas prospects around the world.

An investment decision will be based on the likely market price for Cook Inlet gas and that price will be determined by the most likely alternative gas supply. The most likely alternative supply for Cook Inlet is imported LNG. Hence, gas produced from the Cook Inlet resource might be expected to be priced at or even slightly above that of imported LNG, which is currently estimated to be somewhere between $11.00-$14.00/Mcf.[+]

As explained above, if a company were to invest about $3.6 billion to find and produce about 1.5 Tcf of the Cook Inlet gas resource, pricing the gas at $13.00/Mcf, the payback is roughly 4 years. For at least the next 10 years, however, the Railbelt market to meet the predicted shortfall is too small to meet the payback requirement, so the only viable path to accommodate development of the Cook Inlet gas resource is the export market. Yet, exporting sufficient volumes of gas to repay the investment would mean most of the gas will not be available to the Railbelt over the long term.

---

[*] Although gross investment and gross revenues from the projects are the basis for estimating payback period in this analysis, the rate of return is not estimated herein.

[+] Cook Inlet gas might be expected to sell for a slight premium compared to imported LNG given the higher reliability of the Cook Inlet supply-chain when compared to the LNG supply-chain.

North Slope Reserves

Alaska-Stand-Alone-Pipeline

This project will require the State of Alaska to finance and build the pipeline. Assuming $7.5 billion investment and 97% throughput for the first 8 years, the payback period is roughly 15 years. It is unlikely this project is viable, if the state also were to finance the Susitna River dam project.

Fairbanks Pipeline Co.

Assuming the 18-inch-diameter North Slope to Fairbanks supply option (with the complete build-out to Southcentral several years later), state financing of the incremental cost above the base-case,and a gas volume to Fairbanks based on current demand, payback in the is about 2½ years.

All-Alaska Pipeline

The project will require the State of Alaska to finance and construct the pipeline and LNG plant, which is predicated on pre-selling a sufficient volume of LNG through long-term contracts to ensure a sufficient revenue stream to pay the back the bonds that would presumably be sold to finance construction.

It is unlikely this project is viable if the state must finance the entire cost of $50 billion or more, and also because “pre-selling” a sufficient volume of gas, which is necessary to make financing tenable, would appear to be highly problematic due to competition from existing LNG suppliers as well as from those LNG facilities that will come on line in the next 5-10 years.

TransCanada

Project is as problematic as All-Alaska Pipeline for the same reasons.

Imported LNG

In the near-term, importing small volumes of LNG to compensate for the expected shortfall of Cook Inlet gas would probably rely upon shipboard regasification. If Cook Inlet gas supply then continues to decline – about 8% annually – and neither the Cook Inlet gas resource nor North Slope gas is available, the volume of imported LNG would increase to the point where investment in a stand-alone regasification facility will be warranted. None of the LNG analyses cited in this report forecast at what point in the supply curve investment in a stand-alone plant – whether reconfiguration of the existing Kenai LNG plant or a new plant – might be economically justified.
Depending upon throughput, the tolling fee for a stand-alone facility might be considerably higher than cited above, which assumes the plant is operating at or near

full capacity. For instance, if the stand-alone facility were to come on line when the shortfall of Cook Inlet gas is about 50% of demand, and assuming a maximum 4-year payback period, then a $2.00/Mcf tolling fee would be required, pushing the cost of LNG delivered to Southcentral pipeline system as high as $15.50/Mcf, $1.50 more per Mcf than were the LNG plant to be operating at full capacity. (This is not an issue with shipboard regasification, which is always at 100% capacity.)

Viable Options

Assuming the State of Alaska finances the Susitna River dam project, it seems unlikely that the state would also be able to finance the Alaska-Stand-Alone-Pipeline or the North Slope to Valdez pipeline and liquefaction plant, not only because financing one project limits the capacity to finance other energy projects, but also because of the likely political opposition to state financing of more than one large-scale, energy-supply project.[*]

Therefore the most viable, natural gas-supply options are imported LNG, Fairbanks Pipeline Company North Slope to Southcentral "Arctic Fox" pipeline, Cook Inlet gas resource.[+]

[*] The converse would also hold: If the state were to fund the Alaska-Stand-Alone-Pipeline or the North Slope to Valdez pipeline, financing the Susitna dam may not be feasible. Further, either one of the gas-supply projects would supply ample gas to meet all Railbelt energy demand for electricity and space heating, which would make the hydropower project superfluous.

[+] This list is essentially a "best guess" of viability given the many uncertainties. For instance, a decision to construct the Alaska-Stand-Alone Gas-Pipeline, like a Susitna River dam, is as subject to various political considerations and constraints as it is to financial considerations and constraints.

IV. STATE-OWNED SUSITNA DAM

Apart from meeting the goal of providing 50% of the state's electricity from renewable energy sourced, Alaska Energy Authority justifies the project on more substantial grounds: The dam would supposedly resolve the problem of declining supply of Cook Inlet gas by diversifying energy sources to enhance energy security and reliability, which, according to AEA, is also sure to ensure affordable and stable energy pricing for the Railbelt in the long-term by negating the volatility and price escalation of natural gas that would otherwise occur.[145] AEA's reasoning is problematic.

1. Supply Security

The hydropower dam, if built, would generate about 50% of the electricity used by customers of the Railbelt's electric utilities (assuming AEA's estimate of 2,600-2,800 gigawatt hours annually is accurate.) Put another way, the annual electric output from the dam would provide less than 25% of the total current annual energy used for electric load and space heating in the Railbelt.

Current demand for natural gas by the utilities for electric loads and space heating is about 70 Bcf annually. If the hydropower project were to provide the expected gigawatt hours yearly, then about 19 Bcf of natural gas currently energizing the electric grid will not be necessary. Nonetheless, 19 Bcf for electric generation and 28 Bcf for space heating will still be required. Hence, the problem of future gas supply remains; the dam would do nothing to address the problem of obtaining new gas supply.

Admittedly, while the dam would diversify the Railbelt's energy sources, with the major benefit of insuring against gas-supply disruption during peak gas-demand. If new gas supply were to come from the Cook Inlet resource, the possibility of gas-supply disruption for any reason is remote. If the new gas supply were to come from the North Slope, there is the possible catastrophic failure of the pipeline, but presumably the pipeline will be engineered to withstand probable seismic activity and presumably existing storage in Cook Inlet pipeline system will be maintained to ensure deliverability and reliability in the event of temporary pipeline failure. If imported LNG is the future gas supply, then disruption to the LNG supply-chain is certainly possible and can be expected, but it can also be anticipated and mitigated with sufficient storage to ensure deliverability and reliability.

The dam, therefore, is essentially an insurance policy for a low-probability, gas-supply-disruption event; nonetheless, paying $5 billion for a dam-insurance policy is neither prudent nor reasonable, when other more economical "insurance policies" are available.

2. System Reliability

With a Susitna dam, system-wide reliability would not be significantly improved, given the already high standard of reliability.

Basically, reliability refers to the ability of the electric system to generate, transmit, and distribute electricity to meet demand on a continuous basis.

"Loss of load" is a measure of reliability. Reliability is usually analyzed in terms of "loss of load probability" (LOLP); LOLP is the measure of the probability that a system demand will exceed capacity during a given period; often expressed as the estimated number of days over a long period, frequently 10 years or the life of the system.

LOLP was approximately 8 percent in the Fairbanks area in 2002, and below 1 percent in the Anchorage and Kenai areas; in other words, in 2002, Anchorage customers experienced loss of electricity for no more than 20 minutes in the entire year. [146] This compares to an industry standard of 10 percent.[147]

Maintaining a 10 percent LOLP requires an approximate 22 percent reserve margin in each of the three major electric-power service areas – Kenai Peninsula, Anchorage/Mat-Su, Fairbanks. These area-level reserve margins correspond to utility-level reserve margins of 37 percent for Golden Valley Electric Association, and 40 percent for Municipal Light & Power, and Chugach Electric Association.[148] As of 2009, the Railbelt had a total available generating capacity of 1418 MW, almost twice the capacity necessary to meet total load at the time.[149]

These high generating reserve margins are necessary, because of limited transmission capacity between the major load centers of Fairbanks, Mat-SU, Anchorage and Kenai Peninsula. The Railbelt electric transmission grid is essentially a single transmission line running from Fairbanks to the Kenai Peninsula, with limited total transfer capabilities and redundancies. If there were greater transmission capacity and redundancy, then a concomitant reduction in generating capacity and redundancy will not adversely impact system reliability. Therefore, the effect of the dam on the LOLP would be marginal and not significant.

In fact, the proposed 600-MW central-station, hydropower plant is less, not more, reliable than smaller generating facilities distributed in the Railbelt load centers: any large, central-station generating plant is subject to temporary curtailment as well as long-duration shut down due to catastrophic failure stemming from various causes, including acts of God, human error, and equipment malfunctions. Additionally, energy transmission from a central-station power plant is also vulnerable to disruption and catastrophic failure.

3. Energy Affordability

If the incremental security and reliability afforded to the Railbelt electric-power system cannot justify the dam project, then the project might nonetheless still be justified if it were to ensure affordable energy.

If the overall price of energy in the Railbelt is to be significantly lower with the dam than without, it follows the price of electricity from the dam's power plant would be considerably less than the price of gas-fired electric generation. Would it be?

Cost of Electricity

Flowing water is the "fuel" for the dam's generators that convert the water's kinetic energy to electricity; natural gas fuels the generator with its heat energy from combustion.

The cost of electricity produced at the generating station (aka "busbar") is usually expressed in cents per kilowatt-hour ($0.00/Kwh). The busbar cost is the cost of electricity at the generating station and is the sum of the (fixed) capital cost of the generating plant, and the (variable) operating and maintenance, and fuel costs divided by the total annual electric generation in kilowatt-hours.[*]

For the purpose of comparing the busbar costs from the viable gas-supply options, Chugach Electric Association's busbar cost will be the reference cost. CEA's generation plan (2006) forecasts that the cost of electricity from its gas-fired plants in 2015 will be $0.077/Kwh. 2015 is the year the new, efficient, combined-cycle, 183-MW Southcentral Power Plant (SCP) will be on line.[+] [150] Below are the key factors of CEA busbar cost:

- The power plant will decrease CEA's average fuel consumption system wide from 10.7 Mcf per megawatt hour (Mwh) to 8.25 Mcf/Mwh.[*+]
- System-wide efficiency of CEA thermal generation will increase from 31% to 40%.
- Natural gas is estimated to cost $6.79/Mcf (blended average) in 2015.
- Total annual fuel cost will decline with SCP, but total capital and operating costs will increase, therefore, the busbar cost will increase from $0.071/Kwh currently to $0.077/Kwh.

---

[*] Transmission and distribution costs are not included in the busbar cost.

[+] Chugach owns 70%, and ML&P owns 30%.

[*+] One megawatt-hour equals 1,000 kilo-watt hours.

- Busbar cost is $0.077/Kwh of which $0.021/Kwh is operation and maintenance, and $0.056/Kwh is fuel cost (assuming gas price of $6.79/Mcf).

Busbar Cost of Gas-Supply Alternatives

In the table below, CEA busbar cost is estimated for the various gas-supply options. The cost of storage and pipeline transportation from the point of delivery to the generator must be included to calculate busbar cost.

Gas Supply	Delivered Cost/Mcf	Transportation Cost/Mcf	Storage Cost/Mcf*	CEA Busbar Cost/Kwh
Cook Inlet Resource	$13.00	$0.50	$0.02	$0.12
North Slope Reserves	$8.27	$0.50	$0.02	$0.09
Imported LNG	13.00	$0.50	$0.02	$0.12

Busbar Cost of Susitna Hydropower Dam

Estimated busbar cost is $0.13/Kwh.[151]

This estimate assumes a $4.5 billion capital cost for the project and no financing costs. The capital cost is likely to be higher and the financing cost would be substantial.

Effect of Susitna Dam on Energy Affordability

The busbar cost of dam will be initially higher than any of the viable gas-supply options. Given that natural gas prices are likely to increase during the next fifty years, hydroelectricity from the Susitna dam is likely to be cheaper on a levelized basis, due to the $0.00 "fuel" cost of water. Therefore, as an example, if natural gas prices were to

* Although the storage tariff is charged only to gas actually stored and delivered from the facility; for purpose of this analysis, the tariff is assumed to be applied to each MCF used during the year. Since 12 Bcf will be stored (and presumed to be delivered) annually and the actual tariff is about $0.11/MCF, if the tariff is charged against each Mcf of the 70 Bcf/yearly, the tariff comes to about $0.02/Mcf.

double during the first 50 years of the hydropower project, the Railbelt consumers' average monthly energy bill for electricity and space-heating would be about 25% lower than it would have been without the project.[*]

4. Susitna Dam Investment Calculus

If the state's main purpose in financing, owning, and operating a large hydropower project is energy security and energy-price control, a hydropower project is not the best investment. If it were, the state would not also be giving serious consideration to financing and building an in-state gas bullet line to ensure an energy supply.[152]

For an investment of about 33% more than Susitna, Alaska-Stand-Alone Pipeline will supply at least 8 times the energy, more than enough gas to meet the Railbelt's entire energy demand for the next 100 years or more. Unfortunately, because the pipeline only conveys gas from the North Slope, it will not ensure long-term stability or affordability of gas prices.

This begs the question of whether there might be another option that would achieve the state's goals of both affordability and secure supply.

As suggested below, a state-financed, -owned and -operated Cook Inlet gas-supply utility would seem to do so.

[*] The proposed dam might cause the gas price to be higher than it would be without the dam, if the reduced demand for natural gas were to increase the transportation tariff.

V. STATE-OWNED NATURAL GAS UTILITY

If a secure, long-term supply of natural gas is necessary for the socio-economic well-being of the Railbelt, then the optimal path would be for the state to establish a state utility to produce its own Cook Inlet gas resource, regardless of whether or not the private sector is willing to develop that resource.

1. Rationale

Just as Susitna River water is a public-trust resource, so is the state-owned gas resource in the Cook Inlet Basin. Alaska Energy Authority has determined a $4.5 billion state investment to develop Susitna hydropower is in the public interest because the dam will ostensibly provide energy security and affordability. The same logic applies even more strongly to the state's gas resource. A state-owned gas utility to find and produce the Cook Inlet gas conforms to the state constitutional mandate to utilize natural resources for the maximum benefit of Alaska residents.

If the State of Alaska were to develop the Cook Inlet gas resource, the investment is likely to be less than $4.5 billion: Unlike a hydropower dam, where the entire project must be built before any energy is generated, the gas resource can and would be developed incrementally.

While this analysis estimates the cost of finding and developing the 7.5 Tcf of the Cook Inlet gas resource to be $18 billion, the resource could be developed in, say, 20-year-supply lots – which, at current demand, would be about 1.5 Tcf – for a cost of about $3.6 billion. The revenues from this volume of gas would be reinvested to develop the next multi-year supply, and so on. Further as more cost-effective, less-impact energy sources become available, such as tidal-power, investment in developing additional gas can be appropriately scaled back.

2. Cost of Energy

The cost of gas delivered to Southcentral would be the costs of exploration, production, operations and maintenance, storage, and transportation, the gas itself, as is the case with Susitna's "fuel," the water, would be valued at $0.00.

The cost to find and develop the gas resource from offshore Cook Inlet is estimated to be $2.40/Mcf at the wellhead; delivering the gas to the utility adds the cost of piping from the new wells to the existing pipeline system (~$0.15/Mcf), the pipeline-system tariff(s) (~\$0.50/Mcf), and storage tariff (~\$0.02/Mcf), for a total price of \$3.07/Mcf.[*] The busbar cost of generating electricity from the state-produced gas would be \$0.046/Kwh –*one third of the busbar cost of Susitna hydroelectricity.*

Further, if the state were to provide the equivalent grant subsidy to develop the gas resource – 50% of total investment – as it proposes to do for Susitna hydropower,[153] then the gas delivered to the utilities would be priced at \$1.57/Mcf, for a busbar cost of \$0.034/Kwh – one-half the cost of the busbar cost of Susitna hydroelectricity equivalently subsidized.

[*]This price does not include financing, or operations and maintenance costs.

VI. EVALUATING SUPPLY ALTERNATIVES

Below is a comparison of the viable energy-supply alternatives from which one may discern the advantages of state investment in its Cook Inlet gas resource.

1. Supply Security

Different factors affect the total amount available to the Railbelt from each energy-supply alternative as well as the circumstances under which the supply may be interrupted.

North Slope Reserves

North Slope gas reserves of about 34 Tcf assure supply for several hundred years at current demand.[154] As this option relies on one pipeline, security of supply is slightly more vulnerable than supply from Cook Inlet where gas can be transported through multiple routes. If demand for gas increases above the pipeline capacity, as might be the case for the Fairbanks Pipeline Co. pipeline, pipeline capacity would have to be increased or another source of supply would be required.

Imported LNG

With the enormous supply of LNG that will be available to the Pacific region in a few years as new LNG terminals come on line, mainly in Australia and Canada, LNG can likely be obtained through long-term, 25-year to 30-year, take-or-pay contracts.[155]

Nonetheless, supply-chain risk exists, including slowdown/shutdown of gas-field operations and LNG terminal operations, and LNG-transport delays. Whether the risk is significantly greater than risks associated with other supply options is unlikely, but management of the risk might be more complicated, since the LNG supply-chain has segmented ownership and management and is spread over vast distances. The risk can be mitigated with storage and spot-market purchases.

Cook Inlet-Private Sector

The geologic assessments all point to substantial undiscovered gas in offshore upper Cook Inlet; nonetheless, until exploration confirms the expected log-normal, gas-field distribution, the risk is there may be significantly less gas than predicted. There may also be obstacles to access in certain offshore areas.

Private development of the gas resource would occur only if gas exports were feasible and permissible. Hence, if private investment were to develop the resource, which is highly unlikely, long-term, gas-supply security for the Railbelt would be problematic, depending on the amount of gas exported.

Cook Inlet-State Utility

Access to some areas will be problematic, especially areas already leased. However, the extant leases, if undeveloped, would revert to the state through default, or the state might buy back leases.

Since the market for the state-owned gas would presumably be restricted to the Railbelt, supply would be assured for decades. The gas resource could be developed sequentially to provide multi-year supply volumes, allowing the next increment of supply to be financed by revenues from existing production.

Susitna Dam

Water for hydroelectric generation is available in known quantity and timing. Drought and dam failure would cause interruption and/or disruption in supply.

Access to land and water is assured, since a federal hydropower license provides for eminent domain, and there appears to be no significant conflicting prior water rights or reservations.

2. Permitting and Construction

Permitting includes all licenses and permits to construct and operate the project.

North Slope Reserves

Fairbanks Pipeline Company contends it can have the pipeline in operation about three years from the time permitting commences.[156]

Imported LNG

Typically, build-out of a new regasification terminal in the United States is estimated to take five years from initial permit application. Presumably, if the Kenai LNG plant were to be reconfigured, total construction time would be. Under current regulations, permitting can take from one year (offshore terminals) to over two years (onshore terminals), assuming minimal public opposition/resistance and a well-coordinated permitting process.[157]

Cook Inlet-Private Sector

Permitting is required for drilling, production wells, platforms,and pipelines. Permitting time frame is relatively short. For instance, Buccaneer claims to have had all permits necessary to drill four offshore wells in Cook Inlet in June 2011, having applied for the permits between November 2010 and January 2011.[158]

Cook Inlet-State Utility

Presumably subject to the same permits as "Cook Inlet-Private Sector" option.

Susitna Dam

Licensing and permitting will take from 7 to 10 years and construction several years.[*] [159]

3. Impact on Local Environment

Local environment includes the land, waters and air shed that would be affected by the proposed energy-supply project.

North Slope Reserves

Direct and indirect impacts to terrestrial environment and aquatic systems during pipeline construction, although cumulative effects from pipeline should not be significant.

Imported LNG

Presumably LNG imports would be delivered at Kenai, an already industrialized area. Construction in marine waters, including mooring, a receiving pipeline, wharf, and on-shore, including storage, pipeline, compressor stations, is not likely to significantly impact the local environment. In fact, this supply alternative has the least impact of any.

Cook Inlet-Private Sector

The Cook Inlet Basin gas resource is dry gas not associated with oil, so typical impacts of oil exploration and production should not be of concern.

---

[*] There is also substantial risk of legal challenge(s) under federal law.

Pre-exploratory drilling and seismic surveys can affect fish and marine life, particularly whales. Drilling disturbs the seabed and benthic habitat within the drill's foot print; drilling muds used to lubricate, cool and regulate, pressure, can be toxic to marine life.

During production, produced water is the largest waste stream generated by the oil and gas industry.[160] Produced water is any water from the well/reservoir brought to the surface. As the preponderance of gas to be discovered in Cook Inlet is expected to be dry gas – given the geological formation and rock strata – produced-water production is much less than that of gas field development associated with oil reservoirs. Produced-water that were to escape into the marine environment is toxic to marine life. Cook Inlet has already experienced significant discharge of produced-water from existing oil and gas production.

Cook Inlet-State Utility

Same as private industry.

Susitna Dam

The watershed is virtually pristine; anthropogenic impacts in the Susitna River watershed are localized and not significant at the watershed scale.

Construction of the dam and associated facilities, including roads and transmission, will have significant impacts on surface land; the reservoir alone will inundate more than 20,000 acres of land and 40 miles of the Susitna River channel, including several miles of tributaries. Regulation of river flow from the dam to the river's outlet in Cook Inlet will affect 184 miles of the watershed, with impacts to fish and wildlife and their habitats accumulating over the life of the dam.

In general, of all the renewable, electric-power supply systems, hydropower has the largest the environmental footprint, not only spatially and temporally (cumulative impacts over time), but also ecologically because freshwater ecosystems are usually the areas of greatest biodiversity and productivity.[161]

4. Impact on the Global Environment

Impact on the global environment for purposes of this analysis is the greenhouse-gas emissions from each option, While global environmental impact is distinct and distinguishable from local environmental impacts, global warming and concomitant climate change significantly impact local environments.

North Slope Reserves

Natural gas produces greenhouse-gas emissions when burned.

Imported LNG

Because energy is required to liquefy natural gas and fuel is burned to transport the LNG, there are more greenhouse-gas emissions per Btu when LNG is used as the fuel source.

Cook Inlet-Private Sector

Natural gas from Cook Inlet produces greenhouse-gas emissions when burned.

Cook Inlet-State Utility

Presumably the same as "Cook Inlet-Private Sector," but since private development of Cook Inlet is likely to result in greater annual gas production, annual emissions from state Cook Inlet production will be less, assuming sales of Cook Inlet gas are restricted to Railbelt utilities.

Susitna Dam

The actual conversion of energy from flowing water to electricity results in no greenhouse-gas emissions. However, the hydropower project itself is a source of greenhouse-gas emissions:

- Construction of the dam, roads, rail extension, airstrip, camps, transmission, and all other associated facilities will rely upon internal-combustion engines and motors, primarily diesel, with their attendant greenhouse-gas emissions. Manufacture and transport of the construction materials, including steel and cement, release greenhouse gases.
- Inundation of surface lands causes submerged vegetation to decompose and release greenhouse gases.
- Reservoir water is likely to thaw permafrost in submerged land, releasing carbon, particularly as methane, that is stored in the permafrost.
- Loss of the carbon-sink from the 20,000 plus acres that will be submerged.
- Downstream hydrologic changes affecting the type and extent of vegetative cover may increase or decrease carbon-sink capacity of the drainage.

Even if it were to be the case that the total greenhouse-gas emissions over the life of the hydropower project from the loss of permafrost, vegetation and construction were significant, it could be argued that these emissions will be offset by the hydropower dam having replaced 19 Bcf of natural-gas fired, electric generation annually. For this argument to be valid, however, the 19 Bcf of natural gas the dam would displace would have to be permanently sequestered and not used elsewhere.

Yet, even if the natural gas displaced by the dam were to be permanently sequestered, the question remains whether the environmental impacts that are avoided by eliminating the emissions from 19 Bcf of natural gas more than offset the impacts to the Susitna watershed from the construction, operation, and decommissioning of the hydropower project.

The impacts to the Susitna River watershed from the dam will significantly alter the hydrologic regime, affecting water quality and quantity, and habitat, as well as fish, wildlife, and plant species composition and distribution. In turn, these changes affect ecosystem functioning. These are the very same impacts to watersheds throughout the world that are wreaked by climate change due to global warming. Therefore, constructing and operating Susitna dam does not attenuate but rather exacerbates the impacts from global warming. Further, the impacts from the dam to the watershed are much more severe than the incremental impacts to watersheds that result from the greenhouse-gas emissions from 19 Bcf annually – 19 Bcf of gas is 0.008% of the 2,500 Bcf combusted worldwide each year.

Therefore, whether the 19 Bcf displaced by the Susitna dam would be permanently sequestered or not, the Susitna dam would result in cumulatively more significant impacts than the gas-fired generation it is intended to replace. Even if the emissions from burning 19 Bcf of natural gas yearly were avoided by the Susitna hydropower project, justification of the Susitna dam project on the basis of its assumed low greenhouse-gas emissions is to trade problematic impacts for definite ones and rests on an illogical "destroy-the-environment-to-save-the-planet" calculus.

The only way to reduce the harm to local environments from climate change due to global warming is through zero- or low-emission energy sources and low-impact power-supply technologies. In other words, if the goal is to reduce local and global environmental impacts from Railbelt gas-fired generation, then the first choice is always to invest in energy-efficient technologies, followed by investment in low-emission, power-supply with minimum environmental impact (acknowledging there is no renewable-energy technology that is truly zero impact), and to ensure the natural gas that would be displaced is permanently sequestered, not exported to another location.

5. Economic Impact

An economic-impact analysis evaluates both benefits and costs for each option, but such an analysis is beyond the scope of this analysis. Still, the relative economic impact from the energy-supply alternatives can be broadly discerned.

Construction of any of the viable energy-supply options will create jobs and purchases of goods and services from Railbelt businesses. After construction, the operation of the projects will provide full-time direct employment.

None of these projects would produce significant revenue for the State of Alaska when compared to projects shipping large volumes from the North Slope to Asia or to North America.

North Slope, Imported LNG, Cook Inlet-Private Sector

These supply options may impede economic development in the Railbelt: If gas prices were to increase significantly over time, then more money is removed from circulation in the local and regional economy, because a significant portion of the producers' revenues from gas sales do not remain in the Railbelt or elsewhere in the state.

Cook Inlet-State Utility

This option will spur greater economic development in the regional economy than any other option, because energy costs will be proportionally less of total expenditures by local business and households than would be the case with the other options:

- By 2015, Cook Inlet gas producers' annual revenues from sales to Railbelt utilities will be approximately $300 million – assuming gas price (at the well head) of $4.25/Mcf, as forecast by Chugach Electric Association. By 2020, when the average natural-gas price is estimated to be at least $6.00, gas producers' annual revenues from sales to Railbelt utilities will be about $420 million.
- With state-produced gas, the wellhead price would be $2.40/Mcf, and annual gas sales to the Railbelt utilities would amount to about $168 million, which is $252 million less than the $420 million that would be paid to private producers under the status quo. Gas price, presumably over several decades, would be stable and not subject to volatility.
- While a significant portion of the $420 million paid to private producers would be immediately removed from Railbelt economy, the $168 million to purchase state-produced gas would be reinvested in finding and developing additional gas supply.
- The bulk of the $252 million that Railbelt energy consumers "save" due to the lower priced, state-produced gas would presumably remain and circulate in Alaska,

albeit some portion of the $252 million will be undoubtedly be spent or invested out of state.

Of course, if the State of Alaska produced the gas, it would not collect property, income, and severance taxes, or earn royalties on gas sales, which would otherwise amount to about $32 million if subject to the usual taxes.[*] [162] Presumably, the state could choose to capture this loss revenue through a "surcharge" on the gas; in turn, this would reduce the amount of savings in the Railbelt by $32 million.

Susitna Dam

Because hydropower will reduce use of natural gas by no more than 25%, at least 48 Bcf of gas annually will still be used for space heating and electricity, assuming Railbelt energy demand does not decline or increase significantly. Gas producers will realize revenues of $310 million annually, a significant portion of which will not be available to the Railbelt economy, and the state will earn about $164 million in power sales from the Susitna dam, which the state will use to repay the bond holders (most of whom could be presumed to reside out-of-state).

With Susitna hydropower dam, the total annual Railbelt "energy bill" for electricity and gas space-heating will be $475 million initially – about $55 million more than if all the energy were supplied by natural gas at the current price. Of course, the state would not receive any tax revenue or royalty payment from Susitna, and if the 19 Bcf of natural gas displaced by Susitna hydropower were not produced and sold to other markets, the state would lose about $8 million annually in tax and royalty payments.

---

[*] In reporting severance tax, income, and property taxes from gas production, the state does not disaggregate these tax revenues by geographic region; whereas royalty payments are reported by region.

6. Comparing Supply Options

POINT OF COMPARISON	NORTH SLOPE	IMPORT LNG	CI-PRIVATE SECTOR	CI-STATE UTILITY	SUSITNA DAM
SUPPLY- SECURITY	HIGH	MODERATE	LOW	HIGH	HIGH
PERMITTING	MODERATE	MODERATE	MODERATE	MODERATE	HIGH
ENVIRONMENTAL IMPACT-LOCAL	LOW	LOW	MODERATE	MODERATE	HIGH
ENVIRONMENTAL IMPACT-GLOBAL	MODERATE	LOW	MODERATE	MODERATE	LOW (?)
ECONOMIC BENEFIT	MODERATE	LOW	LOW	HIGH	MODERATE

VII. RAILBELT ENERGY-SUPPLY SCENARIOS

The optimal energy-supply scenario for the Railbelt region will ensure that the most cost-effective, least-impact energy is delivered to Southcentral and to Fairbanks.

The principal problem facing the Railbelt is the impending depletion of Cook Inlet natural gas reserves. Cook Inlet natural gas currently fuels 80% of total Railbelt electric utility generation and about 75% of Railbelt space heating.

The analysis so far estimates the cost of energy-supply options at the point of delivery to the Railbelt service areas and at the busbar; the next step is to ascertain the effect on the retail rate of energy. Below are the current retail energy rates for major Railbelt population centers, Anchorage and Fairbanks:

Railbelt Area	Current Retail Electric Rate /Kwh	Current Retail Heating Fuel Price/mmBtu
Fairbanks	\$0.22 (Golden Valley Electric) [163]	\$30.00 (fuel oil) \$44.00 (propane) \$23.00 (natural gas) [164]
Anchorage	\$0.114 (Municipal Power & Light) [165] \$0.139 (Chugach Electric)[*] [166]	\$8.30 (Enstar)[167]

1. Susitna Dam Scenario

As explained above, AEA estimates the Susitna hydropower plant busbar cost at \$0.13/Kwh.[+] If Susitna power were sold to the Railbelt electric utilities at the busbar cost, the retail rate of Susitna electricity to utility customers would be the busbar cost

[*] Assuming Chugach Electric's average busbar cost of electricity is \$0.077/Kwh (see above section "Cost of Electricity"), distribution and other costs to the utility to deliver electricity to the residential customer total about \$0.062/Kwh.

[+] This calculation of busbar cost of \$0.13/Kwh does not include costs of financing and operations and maintenance.

plus the utility's cost-of-service (distribution infrastructure, personnel, etc.):* CEA cost-of-service (aka "utility charge") is about $0.06/Kwh and GVEA cost-of-service is about $0.09/Kwh.

Therefore, given a $0.13/Kwh busbar cost, CEA and GVEA ratepayers would pay $0.19/Kwh and $0.22/Kwh respectively.

As explained above, the busbar rate of $0.13/Kwh does not include the cost of financing, or transmission system upgrades; therefore, the actual cost of Susitna electricity at the busbar will be much greater. Exactly how much greater will depend on the actual cost of construction of the entire project, the cost of financing, and the cost of operations and maintenance. A recent analysis, which attempts to account for the aforementioned costs, estimates the retail rate of Susitna hydroelectricity for CEA rate payers could be as much as $0.40/Kwh.+ [168]

2. Natural Gas Scenario

State Gas Utility

As explained above, the most cost-effective, least impact energy-supply option for the Railbelt region is state-produced Cook Inlet natural gas.

Effect on Fairbanks Energy Cost

If state-produced gas were available, it could be delivered to Fairbanks with a 12-inch-diameter pipeline, costing about $500 million.*+

If all Fairbanks electric power and space heating in the industrial, military, commercial, institutional and residential sectors were converted to natural gas, about 30 Bcf would be used annually.[169] The Fairbanks Borough estimates however that 20.5 Bcf/year would be a more realistic number, assuming that all residential and commercial structures in would use natural gas for space heating, and utility electric-power generation and refinery process-power also were to convert to natural gas.[170]

---

* Transmission cost between the busbar the electric utility's service area is not included in this calculation, because AEA has not provided an estimate.

+ If the state were to provide a grant subsidy to pay 50% of the total construction cost, the retail rate would be $0.24/Kwh.

*+ Estimate based on Arctic Fox construction costs, albeit cost of compression may be different for gas shipped from Southcentral to Fairbanks.

Assuming a 20 Bcf throughput, the pipeline tariff would be about $4.24/Mcf; the cost of gas delivered to Fairbanks is estimated to be $7.54/Mcf. If the state applied an equal grant subsidy to its Cook Inlet gas production as it is proposing for the Susitna dam, then the cost of gas delivered to Fairbanks would be $6.04/Mcf.

The retail price of electricity would be $0.18/Kwh, with no grant subsidy, and $0.16/Kwh with a grant subsidy.

The retail price of heating with state-produced Cook Inlet natural gas in Fairbanks is estimated to be about $9.54/Mcf non-subsidized and $8.04/Mcf subsidized, assuming a $2.00/Mcf utility-distribution charge for residential customers.

Effect on Anchorage Energy Cost

The retail price of electricity would be $0.09/Kwh, with no grant subsidy, and $0.04/Kwh with a grant subsidy.

The retail price of heating with state-produced Cook Inlet natural gas in Anchorage estimated to be about $5.07/Mcf non-subsidized and $3.57/Mcf subsidized, assuming a $2.00/Mcf utility-distribution charge for residential customers.

Arctic Fox Pipeline

If the State of Alaska does not produce the Cook Inlet Basin resource, the next most cost-effective, least-impact option is Fairbanks Pipeline Co.'s Arctic Fox pipeline to bring North Slope natural gas to the entire Railbelt. In this scenario, the gas would first be delivered to the Fairbanks areas and later to Southcentral.[*]

Arctic Fox service to Southcentral would be contingent upon building the North Slope to Fairbanks segment with 18-inch-diameter rather than 12-inch-diameter pipeline, then waiting several years to complete the Fairbanks to Southcentral segment when the demand from Southcentral justified completion of the line. The hitch is that the North Slope to Fairbanks "upgrade" from the 12-inch-diameter to 18-inch-diameter costs an extra $250 million, which is not a cost that should be borne by Interior/Fairbanks area consumers, as it is solely for future use by Southcentral.[+] [171] It would reasonable, therefore, for the state to pay for this $250 million "upgrade." A $250 million subsidy is

---

[*] Fairbanks Pipeline Co. believes that it can assure relatively stable gas prices with long-term — up to 30-year — contracts with the major Prudhoe Bay producers.

[+] The pipeline between the North Slope and Fairbanks would also be capable of delivering gas to communities located within 120 miles of its Dalton, Elliot, Steese, and Richardson highways right of way, where about 85% of the Interior residences are located.

one-twentieth the amount the state is proposing to spend on a Susitna River dam, but will provide a greater benefit to the Railbelt than the hydropower project and with less environmental impact.

Effect on Fairbanks Energy Cost

The retail residential price of electricity in Fairbanks would be $0.19/Kwh

The retail price of gas to the residential customer is estimated to be $11.66/Mcf, assuming a $2.00/Mcf utility-distribution charge.

Effect on Anchorage Energy Cost

Gas at the point of delivery to Southcentral would cost $8.27/Mcf.

Chugach Electric Association's retail price of electricity would be $0.15/Kwh

The retail price of gas to the residential customer would be $10.27/Mcf, assuming a $2.00/Mcf utility-distribution charge.

Alaska-Stand-Alone-Pipeline

So far, the State of Alaska has given no consideration to developing its own Cook Inlet gas resource or to he Arctic Fox proposal. Instead, the legislature has been focused mainly on the Alaska-Stand-Alone-Gas Pipeline,[*] which would be entirely financed, owned and operated, by the state.[+]

As proposed, the pipeline would have a capacity of 60% in excess of what is needed in the Railbelt.

Consequently, if there were no long-term supply contracts to utilize this capacity, the tariff on gas delivered to the Railbelt would be astronomical – as high as $15.00/Mcf if operating at 40% throughput. The uncertainty about the markets (presumably export markets) that might be supplied by the excess pipeline capacity is so great the legislature has considered exempting the pipeline from normal tariff regulation. In addition, the legislature has considered requiring that the cost of service (tariff) be set to ensure the predetermined rate of return on its investment, at the same time providing discounted tariffs to "big shippers," who would presumably be the North-Slope-gas producers.[172] Under such a rate-structure, in-state consumers are likely to subsidize whatever the North Slope gas producers export commitments turn out to be.

---

[*] Meanwhile, the governor is focused on a $50-plus billion Trans Canada export project.

[+] The ASAP feasibility analysis does allow for the state to transfer ownership to a private party.

The ASAP project, along with the TransCanada LNG project, is the result of the state's strategy to kill the two "problem-birds" – in-state gas supply and stranded North Slope gas reserves – with a "one-pipeline-stone." Thus far, this fixation on North Slope gas export has been unproductive and has detracted from serious consideration of the more cost-effective alternatives that can better address the problem of an affordable and stably priced energy supply for the Railbelt.

VIII. CONCLUSION

The preceding analysis finds Alaska Energy Authority's recommendation and the Alaska Legislature's authorization to finance, construct, and operate a Susitna River hydropower dam to be ill-advised.

This analysis concludes that the dam would do little to ensure or even enhance reliability/security of Railbelt energy-supply, would have only a moderate effect on energy affordability and would do nothing to alleviate gas-price volatility or gas-price increases. A state-owned and -produced natural gas supply from Cook Inlet appears to be the best option to ensure long-term affordability and security of Railbelt energy supply.

The dam project is a distraction from solving the problem of ensuring a long-term, natural gas supply.

Susitna dam will achieve the goal of providing 50% of electric generation statewide from renewables by 2025. Unfortunately, the goal of "50%-by-2025" is counter-productive energy policy, as it substitutes a well-meaning, but arbitrary goal for sound planning and rationalizes a large-scale hydropower project as a necessary and prudent state investment, when it is in fact an unnecessary and imprudent state investment.

Rather, sound energy policy would establish an optimal approach to energy planning by requiring affordable, stably priced energy with the least environmental impacts, as assessed throughout the project life-cycle.[*] In other words, sound energy policy would prescribe choosing the most cost-effective alternative(s), which is arguably the major prerequisite for achieving "maximum benefit" of state public-trust energy resources, as the state constitution requires.

Therefore, the "50%-by-2025" is bad policy to the extent it obviates an analysis of all alternatives.

Choosing to dispense with a comprehensive analysis to ascertain the most cost-effective energy-supply, energy-efficiency, and energy-conservation options, the state more or less arbitrarily identified a few projects – a dam and/or a pipeline – as the cure for what

[*] The life cycle of a power plant begins with the extraction of raw materials from the earth to make steel and concrete and ends when all materials are returned to the earth.

ails the Railbelt.[+]

In fact, because the proposed Susitna River dam will provide no more than 25% of the total Railbelt utilities' annual energy for electric power and space heating, the dam will not stop energy-price volatility or energy price hikes. The dam simply will not accomplish what its proponents proclaim it will do.

The dam is sub-optimal.

The state would do better to invest in finding and producing its own Cook Inlet gas resource or to finance the Arctic Fox project (or something of similar scale and design). On the other hand, the imported-LNG option (or imported compressed gas, if feasible) would require no significant state financing and would have the least environmental impact to the state, albeit it would be the most expensive gas-supply option compared to a state gas utility or the Arctic Fox project.

There is no reason to build a Susitna dam now, if ever.

Jeopardizing the salmon-bearing Susitna River watershed should be the alternative of last resort, not the first choice.

[+] This is not to ignore AEA's initial evaluation of energy-supply and demand-reduction alternatives – "Alaska Railbelt Integrated Resource Plan Study: Draft Report" (December 2009) – nonetheless, as the report cautions, its evaluation does not provide a sufficiently sound basis for ascertaining the preferred alternatives.

ENDNOTES

[1] HDR Alaska, "Susitna and Chakachamna Preliminary Decision Document Environmental-Energy-Cost," November 12, 2010.

[2] The Alaska State Legislature, 27th Legislature, Full Text, Enrolled SB 42 http://www.legis.state.ak.us/PDF/27/Bills/SB0042Z.PDF

[3] FERC, P-14241-001, Document # 20111027-5016, 10/27/2011.

[4] FERC, P-14241, Document # 20111229-5146, 12/29/2011.

[5] Black & Veatch, "Alaska Railbelt Integrated Resource Plan Study: Draft Report," December 2009.

[6] "Declaring a state energy policy," Alaska Legislature, SCS CSHB 306(FIN) am S.

[7] Alaska Energy Authority, "Railbelt Large Hydro Evaluation," Preliminary Decision Document, November 23, 2010, p. 1.

[8] Energy Information Administration, Department of Energy, "Alaska Electricity Profile, 2007." http://www.eia.doe.gov/cneaf/electricity/st_profiles/alaska.html

[9] Energy Information Administration, Department of Energy, "2007 EIA-906/920/923 Monthly Time Series File (Sources: EIA-906/920/923 and EIA-860)."

[10] Institute of Social and Economic Research, "Alaska Electric Power Statistics: 1960-2001," University of Alaska-Anchorage, 2003.

[11] Energy Information Administration, Department of Energy, "2007 EIA-906/920/923 Monthly Time Series File (Sources: EIA-906/920/923 and EIA-860)."

[12] Chugach Electric, "Table monthly sales and revenue data for Chugach Electric Assn," Open Energy Information.
http://en.openei.org/wiki/Chugach_Electric_Assn_Inc.
& Energy Information Administration, Department of Energy

[13] Black & Veatch, "Alaska Railbelt Integrated Resource Plan Study: Draft Report," December 2009, p. 6-2.

[14] HDR Alaska, "Susitna and Chakachamna Preliminary Decision Document Environmental-Energy-Cost," November 12, 2010.

[15] HDR Alaska, "Susitna Hydroelectric Project Conceptual Alternatives Design Report, Final Draft," HDR Alaska, Inc., November 23, 2009, p. 3.

[16] Black & Veatch, "Alaska Railbelt Integrated Resource Plan Study: Draft Report," December 2009.

[17] Alaska Department of Natural Resources, "Chapter Six**:** Oil and Gas in Cook Inlet**,"** Cook Inlet Areawide Final Best Interest Finding. 6-1, 2009, p. 6-15. http://www.dog.dnr.state.ak.us/oil/products/publications/cookinlet/ciaw_2009_final_finding/CI%20PrelimBIF%20Chap06-OGOverview.pdf

[18] Alan Bailey, "Alaska Offshore Special Report: The lure of the Cook Inlet offshore," Petroleum News, Vol. 16. No.4, January 23, 2011. http://www.petroleumnews.com/pntruncate/626847243.shtml

[19] Alan Bailey, "Alaska Offshore Special Report: The lure of the Cook Inlet offshore," Petroleum News, Vol. 16. No.4, January 23, 2011. http://www.petroleumnews.com/pntruncate/626847243.shtml

[20] Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA), "Notice of Utility Application," Docket No. U-10-051, Regulatory Commission of Alaska, 7/28/2010, p. 8.

[21] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p.1-3.

[22] Tesoro Corporation, "Comments to Proposed Alaska Stranded Gas Fiscal Contract." July 24, 2006, p. 1. http://www.revenue.state.ak.us/gasline/ContractDocuments/tesoro%20comments.pdf

[23] Black & Veatch, "Alaska Railbelt Regional Integrated Resource Plan Study, Draft Report," November 2009, Figure ES-2, p. xii.

[24] Alaska Department of Natural Resources, "Chapter Six**:** Oil and Gas in Cook Inlet**,"** Cook Inlet Areawide Final Best Interest Finding. 6-1, 2009, p. 6-17. www.dog.dnr.state.ak.us/oil/.../cookinlet/...final.../CI%20PrelimBIF%20Chap06-GOverview.pdf

[25] Complaint, *State of Alaska v. Hilcorp Alaska*. No. AN-12. (Superior Court 3d. 2012) p. 3. http://www.law.state.ak.us/pdf/press/110712-Complaint.pdf

[26] Complaint, *State of Alaska v. Hilcorp Alaska*. No. AN-12. (Superior Court 3d. 2012) p. 3. http://www.law.state.ak.us/pdf/press/110712-Complaint.pdf

[27] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p 18.

[28] Kristen Nelson, "LNG Enstar's fallback position for 95% of Southcentral heating," Petroleum News, Vol. 15, No. 51, December 19, 2010. http://www.petroleumnews.com/pntruncate/397208657.shtml

[29] Cook Inlet Natural Gas Storage Alaska, LLC, Application for New or Amended Certificate of Public Convenience and Necessity, July 21, 2010, p. 10

[30] Chugach Electric Association, “Chugach files new gas supply contract,” News Release, April 8, 2010.
http://www.chugachelectric.com/news/pr2010-04-08.html

[31] Alaska Gasline Development Corporation, “Alaska Stand Alone Gas Pipeline/ASAP: Project Plan,” July 1, 2011, pp. 3-5 – 3-6.
Also, Kurtis Gibson, et al., “Cook Inlet Natural Gas Production Study,” Department of Natural Resources, Oil and Gas Division, June 2011, p.10.

[32] Charles P Thomas et al., “South Central Natural Gas Study,” Strategic Center for Oil and Natural Gas, June 2004, p.2.

[33] Charles P Thomas et al., “South Central Natural Gas Study,” Strategic Center for Oil and Natural Gas, June 2004, p. 20.

[34] Peter J. Stokes, et al., Petrotechnical Resources of Alaska, “Cook Inlet Gas Study-An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers,” March 2010, ,p. 27.
http://www.mlandp.com/redesign/Energy_Topics/praexecutivesummary.pdf

[35] Kurtis Gibson, et al., “Cook Inlet Natural Gas Production Study,” Department of Natural Resources, Oil and Gas Division, June 2011, p.9.

[36] House Finance Committee, Minutes CS Senate Bill No. 309, April 16, 2010
http://www.legis.state.ak.us/basis/get_single_minute.asp?session=26&beg_line=02725&end_line=03285&time=1047&date=20100416&comm=FIN%20%20%20%20%20%20%20&house=H

[37] Peter J. Stokes, Petrotechnical Resources of Alaska, “Cook Inlet Gas Update -2012,” October 2012, p. 15.
www.petroak.com/pdf/CI_Gas_Supply_Update_102312.pdf

[38] Enstar Natural Gas Company, “Enstar Natural Gas Company’s Petition for Authorization to Recover Gas Storage Costs,” Regulatory Commission of Alaska, Docket No. U-11-003, January 11, 2010.

[39] Charles P. Thomas, et al., “Cook Inlet Natural Gas Reservoir and Storage,” Science Applications International Corporation, December 31, 2007, p. 3-1.

[40] Alaska Department of Natural Resources, “Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves,” December 2009, p.17.
http://www.dog.dnr.state.ak.us/oil/programs/resource_evaluation/res_eval_pub/Cook%20Inlet%20Reserves_DNR.pdf

[41] Cook Inlet Natural Gas Storage Alaska, LLC, “Application for New or Amended Certificate of Public Convenience and Necessity,” July 21, 2010, p. 8.

[42] Black & Veatch, "Alaska Railbelt Integrated Resource Plan Study: Draft Report," December 2009, p.3-6.

[43] Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA), "Notice of Utility Application," Docket No. U-10-051, Regulatory Commission of Alaska, 7/28/2010, p. 10.

[44] Bill White, "Southcentral Alaska gas storage, LNG imports discussed," Alaska Natural Gas Transportation Projects, September 26, 2011.
http://www.arcticgas.gov/print/Southcentral-Alaska-Gas-Storage-LNG-Imports-Discussed

[45] Charles P. Thomas, et al., "Cook Inlet Natural Gas Reservoir and Storage," Science Applications International Corporation, December 31, 2007, p. iv.

[46] Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA), "Notice of Utility Application," Docket No. U-10-051, Regulatory Commission of Alaska, 7/28/2010, pp. 13 & 15.

[47] Tim Bradner, "Utilities, gas producers beef up their systems," Alaska Journal of Commerce, October 29, 2010.
http://www.alaskajournal.com/stories/102910/oil_ugp.shtml

[48] Peter J. Stokes, Petrotechnical Resources of Alaska, "Cook Inlet Gas Update -2012," October 2012, p. 3.
www.petroak.com/pdf/CI_Gas_Supply_Update_102312.pdf

[49] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p.2.

[50] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. xvii.

[51] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p 36.

[52] Shaw Alaska, "Commercial Future of the Kenai LNG Plan," April 2006. p.10-1.

[53] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. xvi.

[54] USGS, "Assessment of the Undiscovered Oil and Gas Resources of the Cook Inlet Region, South-Central Alaska, 2011." National Assessment Oil and Gas Fact Sheet, p.2.

[55] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, pp. 62-63.
See also, David m. Hite, "Cook Inlet Resource Potential 'Missing Fields' Gas (and Oil) Distribution/Endowment a Log-Normal Perspective," U.S. Department of Energy, 2006 South Central Energy Forum, September 20-21, 2006, p. 16.

[56] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, pp. 74-75.

[57]Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 71.

[58] Peter J. Stokes, et al., Petrotechnical Resources of Alaska, "Cook Inlet Gas Study-An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers," March 2010. http://www.mlandp.com/redesign/Energy_Topics/praexecutivesummary.pdf

[59]Alan Bailey, "Apache running Cook Inlet test seismic," Petroleum News, Vol. 16. No. 15, April 10, 2011.
http://www.petroleumnews.com/pnads/588417312.shtml

[60] Kay Cashman, "Jack-ups headed north," Petroleum News, Vol.15, No.17, April 25, 2010
http://www.petroleumnews.com/pntruncate/191498595.shtml

[61] Kay Cashman, "Escopeta gets air permit for jack-up rig," Petroleum News, Vol. 16. No. 20, May 15, 2011.
http://www.petroleumnews.com/pnads/64769233.shtml

[62] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. xvi.

[63] Peter J. Stokes, et al., Petrotechnical Resources of Alaska, "Cook Inlet Gas Study-An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers," March 2010.
http://www.mlandp.com/redesign/Energy_Topics/praexecutivesummary.pdf

[64] Alaska State Legislature, Senate Resources Standing Committee, March 31, 2010, p.21.
http://www.legis.state.ak.us/pdf/26/M/SRES2010-03-311532.PDF

[65] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 121.

[66] Eric Lidji & Kay Cashman, "3.5tcf ! or ?" Petroleum News, Vol. 16. No.46, November 13, 2011.
http://www.petroleumnews.com/pnads/976886805.shtml

[67] State of Alaska, "Sample Lease," pp 5-6.
http://dog.dnr.alaska.gov/Leasing/Documents/Sample_Lease.pdf

[68] Legislative Budget and Audit Committee, Alaska Legislature, "Stranded Gas Hearings (minutes)," April 20, 2005, http://lba.legis.state.ak.us/sga/0504201540.shtml

[69] Dianna Lewis, Alaska Department of Natural Resources, personal communication, March 15, 2012.

[70] Kevin Banks, "The Explorers 2010: What's cooking in the Cook Inlet," Petroleum News, Vol. 15, No. 46, November 14, 2010.
http://www.petroleumnews.com/pntruncate/296734464.shtml

[71] Department of Natural Resources, "Cook Inlet Areawide, Preliminary Sales Results," May 20, 2009.
http://dog.dnr.alaska.gov/Leasing/Documents/SaleResults/CookInlet/2009/CIAW2009_ResultsMap.pdf
Department of Natural Resources, "Cook Inlet Areawide, 2010, Preliminary Sales Results," May 26, 2010.
http://dog.dnr.alaska.gov/Leasing/Documents/SaleResults/CookInlet/2010/CIAW2010_ApparentHighBiddersMap.pdf

[72] House Finance Committee, Minutes CS Senate Bill No. 309, April 16, 2010.
http://www.legis.state.ak.us/basis/get_single_minute.asp?session=26&beg_line=02725&end_line=03285&time=1047&date=20100416&comm=FIN%20%20%20%20%20%20%20&house=H

[73] Eric Lidji, "Nikiski LNG plant to continue buying gas," Petroleum News, Vol. 16, No. 52, December 25, 2011.
http://www.petroleumnews.com/pnads/424060709.shtml

[74] Department of Natural Resources, "Cook Inlet Areawide Lease Sale, 2011, Preliminary Sales Results," June 22, 2011.
http://dog.dnr.alaska.gov/Leasing/Documents/SaleResults/CookInlet/2011AB/CI_2011AB_Apparent_High_Bidders.pdf.

[75] Kay Cashman, "Escopeta runs into problems drilling upper Cook Inlet well," Petroleum News, Vol. 16, No.40, October 9, 2011.
http://www.petroleumnews.com/pnads/472569923.shtml

[76] Eric Lidji, "Buccaneer planning ambitious 2012," Petroleum News, Vo. 16, No. 51, December 18, 2011.
http://www.petroleumnews.com/pnads/9449135.shtml

[77] Eric Lidji & Kay Cashman, "Escopeta announces a historic Cook Inlet discovery; officials remain skeptical," Petroleum News, Vol. 16, No. 46, November 13, 2011.
http://www.petroleumnews.com/pnads/976886805.shtml

[78] Dan Joling, "Cook Inlet petroleum lease sale thrills Alaska officials," Anchorage Daily News, June 23, 2011.
http://www.adn.com/2011/06/22/1930785/high-bids-top-11-million-in-cook.html

[79] Eric Lidji & Kay Cashman, "Escopeta Succeeds," Petroleum News, Vol.15. No.48, November 28, 2010.
http://www.petroleumnews.com/pntruncate/964689584.shtml

[80] Kristen Nelson, "Apache working 800,000 Cook Inlet acres," Petroleum News, Vol. 16, No. 44, October 30, 2011.
http://www.petroleumnews.com/pnads/762379427.shtml

[81] http://www.offshoreenergytoday.com/alaska-drilling-in-cook-inlet-will-bring-500-new-jobs/

[82] Wesley Loy, "Escopeta almost there," Petroleum News, Vol. 16, No. 36, September 4, 2011.
http://www.petroleumnews.com/pnads/662324318.shtml

[83] Kay Cashman, "Explorers 2011: It's almost free," Petroleum News, Vol. 16, No. 47, November 20, 2011.
http://www.petroleumnews.com/pnads/47148928.shtml

[84] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, pp. 75-76.

[85] Patti Epler, "Alaska's natural gas conundrum," Alaska Dispatch, January 24, 2011.
http://alaskadispatch.com/dispatches/energy/8427-alaskas-natural-gas-conundrum

[86] Kevin Banks, "The Explorers 2010: What's cooking in the Cook Inlet," Petroleum News, Vol. 15, No. 46, November 14, 2010.
http://www.petroleumnews.com/pntruncate/296734464.shtml

[87] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 130.

[88] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 130.

[89] Eric Lidji & Kay Cashman, "Escopeta Succeeds," Petroleum News, Vol.15, No.48, November 28, 2010.
http://www.petroleumnews.com/pntruncate/964689584.shtml

[90] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p.131.

[91] Peter J. Stokes, et al., Petrotechnical Resources of Alaska, "Cook Inlet Gas Study-An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers," March 2010, p. 17.

[92] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p.131.

[93] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p.131.

[94] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 127.

[95] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 127.

[96] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, pp. 127-128.

[97] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p.128.
[98] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, pp. 128-129.

[99] Cook Inlet Natural Gas Storage Alaska, LLC, "Application for New or Amended Certificate of Public Convenience and Necessity," July 21, 2010.

[100] Regulatory Commission of Alaska, "Tariff No. 1 of Cook Inlet Natural Gas Storage Alaska," RCA No. 733 (revised), January 31, 2011.
http://www.cingsa.com/LinkClick.aspx?fileticket=To9gJKc6W1s%3D&tabid=220

[101] Joy Nurre, Regulatory Commission of Alaska, personal communication, November 27, 2012.

[102] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 151.

[103] Beluga Pipeline Company, "Tariff No. 2," Pursuant RCA Order No. P-07-09 (7), July 14, 2008.
Cook Inlet Gathering System, "Tariff No.1," Pursuant RCA Order Nos. P-07-S (2); P-04-20 (16)/U-05-20 (13); P-04-20 (17)/U-04-20 (14), August 16, 2007.
Enstar Natural Gas Company, "Tariff," Pursuant RCA Order No. U-04-31 (2), August 25, 2004.
Kenai Kachemak Pipeline LLC, "Tariff No. 3," Pursuant RCA Order No. P-03-12 (22), July 1, 2005.
Kenai Nikiski Pipeline, "Tariff No. 2," Pursuant RCA Order No. P-04-0 12 (18), March 1, 2007.

[104] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 158.

[105] Alan Bailey, "Three is a row," Petroleum News, Vol. 16, No. 34, August 21, 2011.
http://www.petroleumnews.com/pnads/263126175.shtml

[106] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, p. 3-4.

[107] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, pp. 4-8 – 4-9.

[108] Alaska Gasline Development Corp., "Alaska Stand Alone Gas Pipeline/ASAP: Plan of Development Revision 1," March 2011, Anchorage, AK, pp. 1-2.

[109] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, p. 3-7.

[110] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, pp. 3-19 – 3-21.

[111] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, pp. 4-10.

[112] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, p. 3-10.

[113] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, February 27, 2011.

[114] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, November 10, 2011.

[115] Fairbanks Pipeline Company, "PP Table of Intrastate Gas Options," Economic Data, May 7, 20011.
http://fairbankspipelinecompany.com/pdf/Economic/PP_Table_of_Intrastate_Gas_Options.pdf

[116] Fairbanks Pipeline Company, "PP Table of Intrastate Gas Options," Economic Data, May 7, 20011.
http://fairbankspipelinecompany.com/pdf/Economic/PP_Table_of_Intrastate_Gas_Options.pdf

[117] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, February 27, 2011.

[118] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, February 11, 2011.

[119] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, November 10, 2011.

[120] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, February 27, 2011.

[121] Nick Snow, "Partners release Alaska gas pipeline, LNG facilities cost estimate," Oil and Gas Journal, October 5, 2012.
http://www.ogj.com/articles/2012/10/partners-release-alaska-gas-pipeline-lng-facilities-cost-estimate.html

[122] Harold Heinze, "In-State Natural Gas & Value Added Manufacturing," Alaska Natural Gas Development Authority, October 2010, p.15.

[123] Bill White, "Alaska's Arctic: Can the gas reserves find a way to market?," Office of Federal Coordinator, Alaska Natural Gas Transportation Projects, September 27, 2011, p. 8.

[124] Harold Heinz, personal communication, 4/29/2011.

[125] Alaska Gasline Port Authority, "Alaska Gasline Project," 2010. http://www.allalaskagasline.com/Pages/AlaskaGaslineProject.php

[126] Harold Heinze, "In-State Natural Gas & Value Added Manufacturing," Alaska Natural Gas Development Authority, October 2010, p.15.

[127] Kristen Nelson, "BP-GVEA contract supplies 20 years of gas," Petroleum News, Vol. 17, No 39, September 23, 2012.
http://www.petroleumnews.com/pnads/718029273.shtml

[128] Eric Lidji, "Flint Hills permitting LNG project," Petroleum News, Vol. 17, No. 48, November 25, 2012.
http://www.petroleumnews.com/pnads/99748933.shtml

[129] Kristen Nelson, "BP-GVEA contract supplies 20 years of gas," Petroleum News, Vol. 17, No 39, September 23, 2012.
http://www.petroleumnews.com/pnads/718029273.shtml

[130] Bill White, "Guide to Alaska natural gas projects," Alaska Natural Gas Transportation Projects, August 15, 2011. http://www.arcticgas.gov

[131] Bill White, "Southcentral Alaska gas storage, LNG imports discussed," Alaska Natural Gas Transportation Projects, September 26, 2011.
http://www.arcticgas.gov/print/Southcentral-Alaska-Gas-Storage-LNG-Imports-Discussed

[132] Tim Bradner, "Gas shortage looming, imports are only option," Alaska Journal of Commerce, November 2, 2012.
http://www.alaskajournal.com/Alaska-Journal-of-Commerce/November-Issue-1-2012/Gas-shortage-looming-imports-are-only-option/

[133] Tim Bradner, "Utilities negotiate for LNG," Morris News Service-Alaska, July 6, 2011. http://www.homernews.com/stories/070611/business_unflng.shtml

[134] Alaska Gasline Development Corporation, "Greenfield Liquefied Natural Gas (LNG) Economic Feasibility Study," Alaska Stand Alone Pipeline, June 8 2011, pp. 2-9 – 2-11.

[135]Tim Bradner, "Gas, electric utilities explore LNG to Southcentral," Peninsula Clarion, November 9, 2010.
http://www.peninsulaclarion.com/stories/110910/new_733471133.shtml

[136] Alaska Gasline Development Corporation, "Greenfield Liquefied Natural Gas (LNG) Economic Feasibility Study," Alaska Stand Alone Pipeline, June 8, 2011, p. 4-16.

[137] Alaska Gasline Port Authority, "Alaskan LNG Exports Competitiveness Study," July 27, 2011, p. 22.

[138] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, November 10, 2011.

[139] Shearman & Sterling LLP, "Financing LNG Regasification Facilities," Executive View.com, June 11, 2010.
http://executiveview.com/knowledge_centre.php?id=11905

[140] Shaw Alaska, "Commercial Future of the Kenai LNG Plan," April 2006, p. 8-6.

[141] Alaska Gasline Development Corporation, "Greenfield Liquefied Natural Gas (LNG) Economic Feasibility Study," Alaska Stand Alone Pipeline, June 8, 2011, p. 2-11.

[142] Shaw Alaska, "Commercial Future of the Kenai LNG Plan," April 2006, p. 8-6.

[143] Tim Bradner, "Gas, electric utilities explore LNG to Southcentral," Peninsula Clarion, November 9, 2010.
http://www.peninsulaclarion.com/stories/110910/new_733471133.shtml

[144] See U.S. Energy Information Administration, "The Global Liquefied Natural Gas Market: Status and Outlook," Report #DOE/EIA-0637, December 2003.
http://www.eia.gov/oiaf/analysispaper/global/lngindustry.html

[145] Hugh Short, "Susitna-Watana dam good for the long term," Anchorage Daily News, October 7, 2011.
http://www.adn.com/2011/10/07/2109907/susitna-watana-dam-good-for-the.html

[146] R.W. Beck, "Railbelt Energy Study: Final Report," January 15, 2004, p. E-5.

[147] *Ibid*.

[148] Alaska Legislature, Alaska Energy Policy Task Force, "Report on the Railbelt, Findings and Recommendations," 12/2003, p. 26.

[149] Alaska Energy Authority and Institute for Social and Economic Research (University of Alaska Anchorage), "Final Energy Statistics 2010," Anchorage, June 2012. Table 1.b.

[150] Chugach Electric Association, "2006 Generation Plan," May 2007, Appendix 10, p. 3.
http://www.chugachelectric.com/pdfs/projects/2006_IRP_Appendix_10.pdf

[151] Alaska Energy Authority, "Railbelt Large Hydro Evaluation," Preliminary Decision Document, November 23, 2010, p. 8-1.

[152] Alaska Gasline Development Corporation, "Alaska Stand Alone Gas Pipeline/ASAP: Project Plan," July 1, 2011, pp. 4-8 – 4-9..

[153] Alaska Energy Authority, "Railbelt Large Hydro Evaluation," Preliminary Decision Document, November 23, 2010, p. 8-1.

[154] EIA, "Bring Alaska North Slope Gas to Market," 2009. http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ansng.html

[155] Gazprom, "Gazprom on Foreign Markets," http://eng.gazpromquestions.ru/?id=4#c526

[156] Fairbanks Pipeline Company, "An Alaskan Solution, Presentation to Governor's Office," Energia Cura, January 6, 2011, p. 21, www.fairbankspipelinecompany.com/pdf/1-6- _Presentation_to_the_Governor's_Office.pdf

[157]Center for Liquefied Natural Gas, "Summary of the NPC LNG Report," September 2003 http://www.lngfacts.org/LNG-Research/NPC-Report-2003.asp

[158] "Buccaneer provides update on operations in the Cook Inlet, Alaska," Scandinavian Oil Gas Magazine, January 21, 2011. http://www.scandoil.com/moxie-bm2/by_province/americans_offshore/alaska/buccaneer-provides-update-on-operations-in-the-coo.shtml

[159] HDR Alaska, "Susitna Hydroelectric Project Conceptual Alternatives Design Report, Final Draft," HDR Alaska, Inc., November 23, 2009, p. 17.

[160] Lisa Sumi, "Produced water from oil and gas production," Oil and Gas Accountability Project, October 28, 2005, p. 2.

[161] See Mark Z. Jacobson, "Review of solutions to global warming, air pollution, and energy security," Energy & Environmental Science (www.rcs.org/ees), October 31, 2008

[162] Charles P Thomas et al., "South Central Natural Gas Study," Strategic Center for Oil and Natural Gas, June 2004, p. 155.

[163] Golden Valley Electric Association, http://www.gvea.com/rates/rates.

[164] Fairbanks Natural Gas, LLC, "Your Utility Bill, How Does Natural Gas Compare to Other Energy Sources?" http://www.fngas.com/calculate.html

[165] Municipal Light & Power, "Rates and Tariff," http://www.mlandp.com/redesign/rates_and_tariff.htm

[166] Chugach Electric Association, "Rate Information," http://www.chugachelectric.com/customer-service/rate-information

[167] Enstar Natural Gas Company, "Rates and Regulatory," http://www.enstarnaturalgas.com/RatesRegulatory.aspx

[168] Steve Colt, "Susitna-Watana Cost of Power Analysis," National Renewable Energy Laboratory, July 16, 2012. www.iser.uaa.alaska.edu/.../Colt_Susitna_Cost_of_Power_Analysis

[169] Northern Economics, "Fairbanks North Star Borough Gas Distribution System Analysis," June 29, 2012, pp 10-11, 13-14.

[170] *Ibid*. p. 13.

[171] Alexander Gajdos, Fairbanks Pipeline Company, personal communication, March 10, 2012.

[172] House Resource Committee, Alaska Legislature, 2/10/2012. http://www.legis.state.ak.us/pdf/27/M/HRES2012-02-101307.PDF