“Watana”

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The Case for a Susitna River Dam:

Does It Hold Water?

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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.[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]

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, mainly 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 fifty 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:[3] this report finds there are significant issues associated with a Susitna River hydropower project, not the least of which is the cost of energy (electricity) from the project. This report does not dispute that a publicly subsidized energy project is likely the only approach to achieve affordable, stable, energy-pricing in the long-term, but concludes the Susitna dam will not achieve this goal, whereas this goal could be achieved if the state were instead to finance, find, and produce its own natural-gas resource from the Cook Inlet Basin.

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

With an investment in Cook Inlet of no more and probably less than that required to build a Susitna River hydropower project – the electricity from which would provide at most only one-fourth of the total current Railbelt utility energy-demand – the state can meet the entire current Railbelt demand for electric power and space heating for the next 100 years at a cost per Btu at least half that of Susitna 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 LNG (liquefied natural gas) 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 local environment.

This report relies mainly on publicly available information and analysis, primarily secondary sources. Hence, the cost estimates of the various gas-supply options 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 and not of the Natural Heritage Institute for which he serves as consulting staff.

EXECUTIVE SUMMARY

- The Watana dam project will decrease reliance on natural gas for electric-power generation by less than 50% at current demand.

- The dam will reduce consumption of natural gas for 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 and no later than 2023.

- 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 so accepts responsibility for meeting that need.

- Eighteen billion dollars (2010$) is estimated to be the cost of finding and producing at least 7.5 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.

- Imported LNG is available to meet future gas-supply demand in the Railbelt; requires the least capital investment, and has the least environmental consequences of any other gas-supply option or Watana.

- 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.

- Watana will not substantially increase energy reliability or affordability in the Railbelt.

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

- The Watana 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 Watana, enough to meet current Railbelt energy demand for the next 100 years, at one-half the price/mmBtu as Watana.

- State financed and produced Cook Inlet natural-gas resource promises to confer the greatest direct benefit to the Railbelt economy of all the 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 power dam.

RATIONALE FOR THE DAM

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."[4]

Alaska Energy Authority's) justification for its recommendation to build Watana is the project is "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 project that can provide the required amount of electricity by 2025 is a Susitna project.[5]

The Watana hydropower dam would be 184 miles from the river's mouth at Cook Inlet. As currently conceived, the dam is engineered as a 700-foot-high, earth or rock-filled structure, creating a 39-mile-long, 2-mile-wide reservoir 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 several hundred million dollars. This project will be entirely financed by the State of Alaska, half by grant and half by bonds.

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. Natural gas is the energy-source for virtually all electric power and space heating in the Railbelt with the exception of the Fairbanks area.[+]

- At present 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 or shortly thereafter, when there will be no gas left in the existing gas fields.

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[*] Alaska Energy Authority provides no confidence range for this cost estimate.

[+] The Railbelt is so-called because it encompasses the three major regions served by the Alaska Railroad – Kenai Peninsula, Southcentral (Anchorage), and Interior (Fairbanks). Electrically, a single transmission line from Homer through Anchorage to Fairbanks interconnects the Railbelt.

Hence, the uncertainty and concern about future natural gas supply is over the source of future gas and the price of that gas.[6] Watana of course will not produce natural gas, but will instead offset about 21 Bcf natural gas currently used by utilities for electric-power generation.

RAILBELT ELECTRIC GENERATION

- Annual net electric generation statewide is about 6,500 gigawatt hours (2007).
- Utility, industry, and military electric generators in the Railbelt region generate about 5,500 gigawatt hours for 85% of the state total.[7]
- Approximately 4,500 gigawatt hours is generated in Southcentral, and about 1,000 gigawatt hours is generated in the Fairbanks area.[8]
- Excluding industry and military generators, Railbelt utility generators produce about 5,000 gigawatt hours annually, which is about 90% of the Railbelt total net generation.[9]
- In Southcentral approximately 75% of the electricity is generated from burning natural gas, 15% from hydro, and 7.5% from coal and 7.5% from petroleum; in the Fairbanks area, approximately 45% of electricity is generated from burning coal and approximately 55% from burning petroleum.[10]

WATANA POWER 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 about 2,600 gigawatt hours annually – almost 50% of the Railbelt's current net annual electric generation – or 57% of the electricity generated by Railbelt electric utilities (excluding industrial and military generators).[*]
- Watana will 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.[11]

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[*] The estimate of annual energy generation is based on an assumption about the amount of water that will be available for generation over the life of the project, which depends in turn upon 1) the amount of water necessary to maintain minimum flows for aquatic and terrestrial resources; 2) amount of water draining into the upper Susitna watershed; 3) amount of time to fill reservoir, and 4) rate of sedimentation in the reservoir.

- By 2045, however, generation from Watana will supply approximately 40% of the forecasted utility demand, dropping to 35% of the forecasted 2060 utility demand.[12]

SCRUTINIZING THE CASE FOR WATANA

The State of Alaska's case for state financing, ownership, and operation of the Watana hydropower project is premised on the following assumptions:

- Cook Inlet gas is running out.
- The price of future natural gas supplies, whatever the source, will be volatile and increase over time.

Therefore:

- Electric-power generation from the Susitna River will increase the reliability of energy supply by reducing reliance on natural gas.
- Electricity from the Susitna River dam will mitigate both the volatility of natural gas prices and real increase in price over the life of the dam.[13]

Moreover:

- There capital cost of the hydropower facility is too high to be privately financed.
- The environmental impacts from construction and operation of Watana are not significant.
- The Susitna River power dam is the only viable path toward meeting the "50%-by-2025" goal.

The case for Watana mainly hinges on the claim that the price of energy from Watana will be cheaper than that of gas-supply alternatives and will remain stable through the life of the project and that the hydropower facility can be expected to significantly mitigate the price volatility and price rise of energy from natural gas whatever its source in the future.

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

- Current Cook Inlet gas supply situation.
- Potential sources for future natural gas supply to the Railbelt – Cook Inlet Basin, North Slope, imported LNG (liquefied natural gas).
- Viability of the various gas-supply options currently under consideration.
- Viability of Watana in the context of Railbelt energy security and affordability.

- Cost of energy from the likely energy sources.
- Cook Inlet gas resource financed and produced by the state in a manner equivalent to Watana, an option that has yet to be considered.
- The optimal path to energy security and affordability including impacts to the Railbelt economy and environment, both local and global environments.

Bear in mind, Watana will displace no more than 25% of the natural gas supply necessary to meet current utility-based 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.[*] [14] The decision to license and constructing Watana does nothing to mitigate the urgency to find new sources of gas supply.

[*] 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.

COOK INLET GAS SUPPLY STATUS

As mentioned above, a major justification for the Watana hydropower dam project is declining supply of Cook Inlet natural-gas reserves, and the uncertainty about finding and producing the Cook Inlet Basin gas resource.

As will be explained below:

- The existing gas fields (the gas *reserves*) in the Cook Inlet Basin will not be able to produce enough gas to meet current demand.
- Geologists estimate there is plenty of undiscovered gas (the gas *resource*) in the basin to meet demand through the next several decades, which would require major investment in seismic surveys and drilling to explore and discover new gas fields.
- The problem is none of the major oil and gas companies with the financial wherewithal to explore and discover new gas think Cook Inlet is an attractive investment, and further, the smaller companies operating in Cook Inlet do not have financial resources to explore and discover new gas fields even if they were convinced doing so were economically viable.
- Meanwhile, the State of Alaska strategy for finding and developing new Cook Inlet gas fields is to influence investment decisions through tax incentives and its ongoing leasing program.

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.[15]

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. [16]

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.[17]

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 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 (trillion cubic feet) of gas has been produced since 1958.[18]

Only in the last few years, due to the decline of proven gas reserves, has there been targeted exploration for gas in Cook Inlet in existing fields.[19]

DEMAND FOR NATURAL GAS

Since the discovery of natural gas in Cook Inlet about 8.8 Tcf has been produced from the existing Cook Inlet gas fields.

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. On average, space heating uses about 32 Bcf (billion cubic feet) annually and electric-power generation consumes about 38 Bcf annually.

Through the early 1970s, average annual consumption was 163 Bcf for fertilizer production (70 Bcf), for LNG (liquefied natural gas) export (64 Bcf), and for powering oil and gas industry field operations (25 Bcf)[20] and for operating the Tesoro Kenai refinery (4.4 Bcf).[21] There was minimal use of natural gas by Railbelt utilities for space heating or electric power.

A population boom in Southcentral – 170% from 1970 to 2005 – increased the local demand for natural gas, such that annual demand for natural gas increased to approximately 210 Bcf annually on average – 32 Bcf for space heating, 38 Bcf for power production and 150 Bcf for industrial use,[22] Annual natural gas production peaked in the late 1990s through the early 2000s at about 222 Bcf.[23]

In early 2011, ConocoPhillips and Marathon Oil Corp., citing adverse markets in Japan, announced the LNG facility would no longer operate after 2011. Consequently, average

*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. Fairbanks Natural Gas contracts for Cook Inlet gas until mid-2013.

annual demand for natural gas during the remainder of the decade will be about 87 Bcf annually for space heating, electric-power generation (70 Bcf), oil and gas industry field operations (12 Bcf) and the Tesoro refinery (5 Bcf).[24]

COOK INLET GAS FIELDS IN DECLINE

As early as year 2000, utilities, local governments, and Alaska Department of Natural Resources (DNR) evinced concern about the ability of Cook Inlet gas system to meet demand into the future.

- In 2010, Enstar, for the first time ever, no longer had firm contracts for 100 percent of its forecasted needs. By 2012 that unmet need – forecast gas not under firm contract – will grow to approximately 1.5 Bcf. The unmet need is larger in 2013, about 10 percent of supply needed; by 2014, 45 percent of Enstar's gas demand will be unmet; by 2017, more than 50% of its gas need is unmet.[25]
- ML&P, which owns a third of the Beluga gas field, will also have a small supply deficit after 2013.[26]
- For the past 20 years Chugach Electric Association (CEA) has purchased natural gas from four separate suppliers. CEA used the last of that gas early in 2011. CEA has negotiated gas contracts with ConocoPhillips and Marathon to meet power-generation demand through 2013, with some gas available through 2015 to meet a portion of demand.[27]

This does not mean, however, there is not enough gas to meet demand through this decade; rather it reflects the uncertainty about the rate at which more gas can be found and produced from remaining reserves and, also, whether gas-field infrastructure is capable of delivering enough gas during periods of high demand.

At best, with sufficient investment in new wells and compression to increase pressure, existing Cook Inlet gas fields could supply enough gas to meet current demand through 2023, after which supply will decline inexorably, about 8% annually until about 2043 when the existing gas fields will no longer produce.[28]

Status of Gas Reserves

Reserves are those quantities of oil or gas that are anticipated to be commercially recovered from discovered (known) accumulations.[29]

Based on an engineering methodology known as "material balance analysis," the state oil and gas division estimates 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.[30] Producing the remaining reserves utilizes seismic acquisition and reprocessing, secondary and tertiary recovery techniques, and drilling infill and extension wells.[31]

In order to maintain adequate gas supply through 2020, many new wells in established gas fields are necessary.[32] Between 2001 and 2009, 128 gas wells were drilled, of which 105 were completed and estimated to produce 519 BCF of gas.[33] Almost all the new wells were onshore on the east side of Cook Inlet in established fields – Ninilchik, Kenai and Deep Creek. Ninilchik surpassed expectation; Kenai wells were average, while Deep Creek wells were marginal.

Based on this information, an estimated 187 wells would need to be drilled between now and 2020 to maintain supply at current demand.[34] If not enough wells are drilled, Cook Inlet natural gas supply currently available to Enstar and CEA is predicted to fall below demand for space-heating and power-generation by 2013.[35] Consequently, the availability of supply through 2023 not only assumes that drilling will keep pace with decline, but also that the gas that would have been exported to Japan remains available to the utilities; this is not assured, however, as ConocoPhillips has stated it may shut in at least some of the gas wells supplying gas to the LNG plant.[*] [36]

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 mentioned above, but also assuring gas-field infrastructure can deliver gas at the exact time it is needed and in the quantity necessary.

The average daily demand for Cook Inlet gas for utility-generated electric power and space heating is about 35 MMcf/day (million cubic feet per day) in the summer and peak winter demand is 168 MMcf/day. Gas demand during a peak winter day can be 12 times the volume of gas used during off-peak periods in the summer.[37]

The concern about deliverability has to do with 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).[38] Pressure drop and water encroachment affects deliverability. [39] Further, when operated with high pressure, gas reservoirs are easily ramped up or down to match variations in gas usage, but as pressure declines a reservoir becomes more prone to damage if it does not produce gas at constant rates.[40]

[*] As explained more fully below (see "Imported LNG").

Thus, the drop in pressure in the Cook Inlet gas reservoirs affects the rate at which remaining gas can be pumped from the particular reservoir into the pipeline to meet demand. The decrease in pressure is jeopardizing delivery of gas during the peak days and hours of winter when space heating and electric demand surge due to the combination of darkness and cold temperature.[41]

The LNG plant closing will compound the deliverability problem. Even when gas reservoirs operated at high pressure, deliverability was a concern, at least during those periods of highest demand during winter days. Nonetheless with the LNG plant operating, the gas system could supply the highest instantaneous winter peak demand, primarily because gas in transit to the LNG plant can be instantly diverted to Southcentral gas and electric utilities.[42]

LNG plant operation also insured deliverability by virtue of keeping gas wells producing in the low-demand summer season that would otherwise have to be ramped down or shut down if the LNG plant or other major industrial users did not exist. Operating gas wells cannot simply be shut off during the summer and then turned on in winter when demand increases, because, once a gas well stops producing, it can be difficult or impossible to restart, particularly in a depleted reservoir. Keeping wells in production during the summer when they are not needed can require flaring the gas or pumping gas into storage. Therefore, when the LNG plant shuts down, the seasonal swing in gas demand by the utility sector will no longer be dampened by what had been year-round LNG demand. Closing the LNG plant underscores the urgency in bringing more storage on line.

Currently, the only in-field storage facilities in Cook Inlet are operated by Union Oil Company at Swanson River Field and Pretty Creek, and by Marathon Oil Company at the Kenai Gas Field. 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. Current storage capabilities are approximately 9 Bcf (the amount of gas that can be stored), with a combined daily deliverability of approximately 90 MMcf/day. These are proprietary storage reservoirs to satisfy contractual commitments of these producers. These facilities are not available to third parties, [43] and they have insufficient capacity to buffer the impact of the closing of the LNG plant. Union Oil intends to expand its storage by using the Ivan River unit 44-36 well on the west side of Cook Inlet. Up to 3 Bcf would be injected over a three-year period during summer months, filling the storage reservoir to capacity to aid in meeting peak demand during the winter beginning in 2012.[44]

Enstar is building gas storage on the Kenai Peninsula. The Cook Inlet Natural Gas Storage Alaska facility is scheduled to be complete in 2012. Working gas will be injected into storage during the summer months when available supply exceeds demand to be withdrawn during winter peak demand. The minimum gas storage based on future estimated demand ranges from 11.1 Bcf in 2020 to 15.7 Bcf in 2040.[45] The facility will cost about $180 million[46] will have an initial storage capacity of 11 Bcf – about 20% of the total annual gas demand for Southcentral/Railbelt gas and electric utilities – delivering up to 150 MMcf/day on peak winter days, and has been designed so that additional compression, separation, dehydration, measurement, and storage injection/withdrawal wells can be accommodated.[47]

In addition to increasing available storage, other measures completed or underway to alleviate the deliverability issue include increasing compression at the Beluga gas field, which supplies fuel to CEA's Beluga power plant and ML&P, as well as modifying the piping configuration of the power plant's gas-inlet unit to accommodate reduced gas pressures.[48]

GAS-SUPPLY OPTIONS

After 2023, maintaining and an adequate supply of 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 LNG.

COOK INLET GAS RESOURCE

Resources are undiscovered oil and gas accumulations believed to exist outside known fields or accumulations based on geologic knowledge and theory. C*onventionally recoverable* resources are resources that could be recoverable using current conventional technology, if discovered. *Conventional economically recoverable* resources are those resources that could be economically viable at specified price levels, if discovered. [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 and the entire upper Cook Inlet subbasin.[50] Most of the gas that has been discovered thus far in Cook Inlet has been found at depths of 3,000 to5,000 feet subsea and undiscovered gas is likely to be found at similar depth.[51]

Following the 1968 discovery of Prudhoe Bay oil, explorers headed for the Arctic, leaving much of the Cook Inlet basin substantially under explored. Even though many of the most evident oil prospects had been drilled in the major folds, some known oil prospects were not explored.[52] The only one of these prospects that has ever been drilled is Corsair in the middle of Cook Inlet, where Shell, Phillips and ARCO drilled a total of five exploration wells between 1962 and 1993 – the wells all had gas shows.[53]

As previously mentioned, the gas that has been developed in Cook Inlet was discovered in the process of exploring for oil. Typically, the gas would be discovered above the oil deposits. Virtually all (94%) of Cook Inlet's proven gas reserves are non-associated,

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

biogenic gas that has no genetic relationship to the origin and distribution of oil in the basin. Therefore, it is not realistic to expect that current exploration based on oil prospects will necessarily lead to an accurate evaluation of the basin's gas potential.[54]

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 an a few large fields within a given basin.

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.[55] There are undiscovered fields with 200 to 1,500 Bcf OGIP (Original-Gas-in-Place[*]) missing from the expected field-size distribution. Therefore, the conventionally recoverable resource is estimated to be approximately 10 to 14 Tcf.[56] More recently, USGS has increased the estimate to 15 Tcf.[+57] Still, a more conservative estimate of conventionally recoverable resource is based just on undiscovered class 6, 7, and 8 gas fields is 7.8 to 10.2 Tcf.[58]

Of course these estimates must be validated by exploration. Unfortunately, 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. There is little reason to believe that the non-associated biogenic gas should not be found in stratigraphic traps throughout the basin 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.[59] 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.[60]

Developing the Gas Resource

1993 was the last time an offshore exploration well was drilled; the well was drilled in the Corsair prospect within the Kitchen Lights Unit lease area. The prospect had been previously drilled four times by Shell, Arco, and Phillips, with the first well drilled in

[*] 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.

1962. The wells all had gas shows, albeit oil was the primary exploration objective. [61] In 2011, Escopeta Oil Company, one of the small independent oil and gas companies, brought a jack-up rig to the Inlet to drill one more well in the Corsair prospect, after which it plans to lease the rig to another company.[62] Otherwise, there has been no exploration in offshore Cook Inlet specifically for gas either by seismic survey or drilling since 1993.

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 – plan to explore for the gas resource. In fact, Chevron hopes to complete the July sale of all its Cook Inlet assets to Hilcorp Energy Company by the end of 2011, contingent on approval from regulators.[63] Marathon and ConocoPhillips have stated that they intend to drill new wells only in their existing gas fields to meet current contract obligations.[64]

In order to find new conventional gas fields in offshore Cook Inlet, 3-D seismic survey is the first step, albeit an expensive one. No company, large or small, has taken this step. The major oil and gas companies have no interest in exploring for new gas and the small companies do not have the financial wherewithal to do so. Nonetheless, the State of Alaska remains inexplicably optimistic that significant exploration for natural gas is just around the bend.

Of course, state acknowledges that Cook Inlet is an expensive place to operate, with some areas difficult to access due to geographic remoteness and varying ownership and management restrictions. Given the world's many regions in which the oil and gas industry might invest, there is vigorous competition for a company's capital, and the expense of exploration is but one of many factors that come into play in investment decisions.[65]

Major Producers: Lack Interest

The reason none of the major producers plan to explore for Cook Inlet gas resource is that Cook Inlet does not provide a return on capital that is competitive with other investment opportunities.[66]

As a representative of Marathon Oil explained to the Alaska legislature,

> The lack of activity is an artifact of historic oversupply of natural gas. With prices well below Lower 48 index prices [this creates] a lack of incentive for additional drilling and further regulatory processes and deterioration in market availability have added to project uncertainty. 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.[67]

The Regulatory Commission of Alaska (RCA) seconds this conclusion:

> Investment capital in Cook Inlet must compete with investment opportunities worldwide [and] risk associated with exploration must be compensated or exploration will go elsewhere.[68]

The assumption has been higher prices in larger markets outside Alaska will encourage industry exploration and production of Cook Inlet gas. Yet even with a growing Pacific Rim market and substantially higher-priced LNG, ConocoPhillips still plans to close its Kenai LNG facility; nor have any other companies evinced interest in finding and developing the Cook Inlet gas resource.

Small Producers: Lack Interest and Financial Capacity

All significant drilling activity in Cook Inlet by the smaller, independent oil and gas companies is either for oil, or for gas in proven fields, mostly onshore.[69] Apache, a Houston-based independent, is planning a multiyear 3-D seismic program on shore and near shore, but Apache is searching for oil not gas.[70] There is no significant exploration for the conventional gas resource at present.

There is at least circumstantial evidence that smaller companies, whose primary objective is Cook Inlet oil, lack the financial capacity to explore for the gas resource, assuming they were to be interested in exploring the gas resource:

- Pacific Energy had promised to bring a jack-up rig to the Inlet. Instead, by March 2009, Pacific Energy only managed to make it as far as Delaware to bankruptcy court, which disposed of its Cook Inlet assets a few months later.[71]

- Pioneer Natural Resources announced on January 4, 2010 it will not pursue development of its Cook Inlet Cosmopolitan prospect and is putting it up for sale.[72] This decision comes after having proclaimed in April 2010 of its being "fully committed to developing from onshore."[73]

- In 2009, Miller Energy Resources Inc, based in Tennessee and doing business as Cook Inlet Energy, purchased a package of west Cook Inlet assets out of bankruptcy previously owned by Pacific Energy, restored a number of shut-in wells to production, and brought the offshore Osprey platform back to life. Along the way, Miller's stock price went from a few pennies to a few dollars. [74] In August 2011 however, several lawsuits were filed against the company alleging the company violated federal securities laws.[75] On Aug. 1, 2011 Miller Energy filed a Form 8-K "current report" with the SEC explaining that some previously filed financial statements, including its Form 10-K annual report filed July 29, contained errors and would be revised as soon as possible. The company added it did not expect any "material changes" in its financial situation.[76]

- Buccaneer Oil, an Australian company, is the newest player in the Cook Inlet Basin. Buccaneer Oil also appears to have limited financial wherewithal: after having announced its intention to purchase a jack-up rig and after having received approval from the Kenai Peninsula Borough in November 2010 for $60 million in tax-exempt bond financing for the purchase,[77] Buccaneer then revealed the purchase would be contingent on raising an additional $80 million from public and private sources. In April 2011, Alaska Industrial Development and Export Authority voted to invest up to $30 million to co-own the rig, which will be used for oil, not gas, exploration in Cook Inlet.[78] Moreover, it is not necessarily the case the rig will stay in Cook Inlet: Buccaneer's business plan includes the option of using the rig in the Chukchi and Beaufort seas.[79]

- Escopeta Oil Co. mobilized a jack-up rig, bringing it to Cook Inlet in August 2011. The circumstances surrounding the transport of the rig suggest the company has limited financial resources. In 2007 Escopeta leased the Kitchen Lights unit from the state. The lease stipulated the company must have a jack-up rig in Cook Inlet no later than June 2010. Escopeta failed to do so, thereby defaulting on its lease. Escopeta appealed the default; the state then acquiesced to Escopeta's promise to have a rig in Alaska by February 2011.[80] Escopeta, however, failed to make the February deadline, setting March as the new deadline, then May,[81] which was then pushed back when Escopeta detained the rig in Vancouver Canada on its way to Alaska due to its violation of the Jones Act. The Jones Act requires ships moving equipment between domestic American ports to be American built, flagged, and manned, but Escopeta used a Chinese flagged vessel instead to transport the rig.[82]

  Why Escopeta violated federal law can only be surmised as an attempt to reduce the drill-rig mobilization expenses: a foreign vessel is cheaper than an American one. In fact, Alaska Senator Begich immediately interceded on the company's behalf stating, "A violation of the Jones Act has occurred but we don't want the penalty to bankrupt the company,"[83] The senator at least believes the company does not have deep pockets. Indeed, Escopeta had struggled for years to secure the financial backing to lease the rig it recently transported to Cook Inlet. It would appear Escopeta lacks the financial capacity to mount a significant exploration effort for new gas fields in Cook Inlet. Although Escopeta has begun drilling a well in its Corsair prospect, Escopeta has stated that it may find another company to lease the rig. Further Escopeta's new CEO has stated the company's new owner had no intention of becoming an operator in Alaska.[84]

With the Kenai LNG export facility out of the picture, there is even less likelihood that a small company would risk the sizeable investment required by offshore drilling. Indeed, prior to the announcement of the LNG facility imminent closure, Buccaneer has been marketing its Cook Inlet lease to potential investors as gas to be sold for export.[85] Now, with the only viable market for new gas to be the very small Railbelt utilities and some potential industrial customers, how will companies attract investors? Even if the Pebble mine were to use natural gas for power, the requirements of a 250 MW mine-mouth generator would not fundamentally change the market profile in terms of investor calculus. Therefore, as LNG export from Cook Inlet is not currently an option, new investment to find and produce the Cook Inlet gas resource is even more problematic.

Yet, the State of Alaska has faith that private enterprise will rise to the occasion.

State of Alaska: Lacks a Comprehensive Plan

While acknowledging the concern about a declining Cook Inlet gas-supply, the head of the state's oil and gas division within the Department of Natural Resources (DNR) remains confident

> . . . 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.[86]

This statement is accurate with respect to finding and producing remaining reserves in existing gas fields, but the director fails to acknowledge there is no significant exploration for the conventional gas resource and without finding the undiscovered gas fields, it is indeed inevitable that Cook Inlet gas supply will fall short of supply.

In short, the state-leasing program has not proven to be an effective strategy for finding and producing new conventional gas fields in the Cook Inlet Basin. Leasing is the traditional approach to bringing state-owned gas and oil into production, albeit gas was just the byproduct of Cook Inlet oil leases. The problem is the state has no ability to ensure leaseholder performance other than to declare the lease in default if stipulated deadlines or conditions go unfulfilled. Usually the affected company will appeal the decision and may then litigate if the appeal process upholds the default. During the period the default is being contested, on-site work usually is halted. Then, in the event the default is sustained and the tract reverts to the state, the state must re-lease the acreage, further delaying exploration.

In 2010, implicitly acknowledging leasing has yet to encourage exploration of the Cook Inlet's conventional gas resource offshore, the state decided to provide a tax credit to encourage exploration for new gas in the waters of Cook Inlet. The special credit is for the first three unaffiliated wells drilled into pre-Tertiary strata using a jack-up drilling rig.

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.* [87]

Yet, if investing in new Cook Inlet gas fields is not competitive with other oil and gas provinces, how does the state tax credit materially change the equation? The state's optimism that small companies will undertake the major exploration necessary to find and then develop the gas resource seems predicated on wishful thinking rather than a strategically sound plan to ensure finding and producing the Cook Inlet gas resource.

Nonetheless, the state's oil and gas division continues to insist the current leaseholders have the capacity and ability to bring new gas on line.[88] If DNR is proven correct, prices of new gas supplies will be high, and likely highly volatile. After all, any new substantial investment in finding and developing gas in Cook Inlet is made with respect to expected returns relative to investment opportunities available elsewhere in the world.[89] Therefore, if private companies were to find and develop conventional gas from as yet undiscovered gas fields in offshore Cook Inlet, the market price would be at or near the market price of the most likely gas-supply: imported LNG.

As will be examined in greater depth below, the Alaska Legislature, however, does not share the Department of Natural Resources' optimism and does not believe the local Railbelt market is sufficiently attractive to private investment in developing new gas supplies. In fact, at one point, the legislature threatened to investigate whether Cook Inlet producers are sitting on leases and not exploring or producing as required under the leases.[90]

Cost to Produce the Gas Resource

As mentioned above, if any company is to find and develop the conventional gas resource in offshore Cook Inlet, the cost to find and produce new gas must be low enough and the market price high enough to justify the investment.

The cost 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.

* Of course, if Escopeta were to complete a well in the Corsair prospect and finds gas – albeit oil is its primary objective – it will presumably qualify for the tax credit, but Escopeta was required to drill by the terms of its 2007 lease; therefore, arguably drilling was not incentivized by the tax credit.

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 $115,000/sq mile, respectively (2004$).[91]
- Exploration wells are estimated to cost from $10 to $20 million, depending on location, well trajectory, depth, and target.[92] Escopeta states the day-rate for a jack-up rig lease will be "much less than $100,000."[*] [93]

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.[94]
- A 2010 utility-commissioned study estimated the cost to drill 128 gas wells in Cook Inlet between 2001 and 2009 between $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 2010-2019.[95]
- 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.[96]
- Gas handling facilities costs are related to processing capacity and are estimated to be $0.025/Mcf/d (million cubic feet per day) for peak throughput capacity.[97]

Operations

No lease-operating-expense reports were available to determine operating cost structure (fixed and variable operating costs) of the Cook Inlet gas fields, because the producing companies consider that information to be proprietary. In the absence of reported information from Cook Inlet producers, the 2004 study could only estimate costs based on available industry data.[98] Variable operating costs can be divided into direct operating cost per Mcf and the cost to dispose of produced water:

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[*] Current day rates in the North Sea and Gulf of Mexico average greater than $100,000, however.

[+] One Mcf releases about 1 million Btu during combustion.

- Fixed operating costs were estimated to be $1,500/well/month.[99]
- 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 Cook Inlet operating conditions because of similar winter conditions and well depths.[100] 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.[101]
- 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.[102]

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. It will be up to the RCA to determine the cost-of-service tariff on the gas stored in the facility.[103]

- The storage tariff will be allocated only to the gas actually stored.
- A Federal Energy Regulatory Commission (FERC) review of 20 storage operator tariffs indicated a median cost-of-service of $0.64/Mcf. Cook Inlet gas storage is expected to be higher cost than Lower 48 gas storage.[104]

Transportation

The charge to transport gas through the pipeline system is called a tariff. The tariff calculation allows for capital recovery at the regulatory rate of return plus cost recovery for operating cost, ad valorem taxes, depreciation, a dismantlement charge, and state and federal income taxes. The tariff charge per Mcf is thus dependent on the transported volumes of gas, with larger volumes resulting in lower tariffs.[105]

- Gas delivered to Southcentral/Railbelt utilities is transported by pipeline. There are five gas pipelines for which a tariff is charged per Mcf:[106]

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 is required to serve new gas fields, there will be a tariff for gas transported through that pipeline. Onshore field gas pipeline costs are based on the recent Kenai-Kachemak pipeline (KKPL) that entered service September 2003. KKPL, a 33-mile, 12-inch-diameter pipeline, cost approximately $25 million, equating to $11.96/diameter-inch/ft (63,000/diameter-in/mi). This construction factor can be scaled and compression added for other similar pipeline projects.[107]

Cost to Find and Develop New Cook Inlet Gas Fields

A 2004 report on Cook Inlet gas contains some estimates of finding and development costs for the gas resource.

- Medium size fields as $152 million for a Class 6 field, $251 million for a Class 7, and $384 million for a Class 8.[108]
- Finding and developing 6.5- 8.5 Tcf (50% of the estimated 13 to 17 Tcf remaining undiscovered reserves in the Cook Inlet) would be $5 to $6 billion.[109]

In light of recent analyses of new producing wells in the existing Cook Inlet gas fields, the 2004 estimate above is too low. 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

* The capital cost of new wells in existing fields is of $1.78 - $2.06/Mcf, with wells drilled between 2010-2019 forecast to cost between $2.50 - $4.30/Mcf.

gas resource. Assuming a $3.6 billion dollar investment to find and develop about 1.5 Tcf of gas resource, which would provide about 20-year supply to Southcentral at current demand and assuming a 4-year payback on investment, the cost of gas delivered to Southcentral would be about $13.00/Mcf. Presumably, this price cannot be higher that the most likely alternative source of supply – imported LNG.

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.[110]

NORTH SLOPE GAS

There are several proposals to pipe North Slope gas to the Railbelt, including two "bullet" lines from North Slope directly to Southcentral with a spur to Fairbanks; a North Slope to Valdez pipeline, with a spur to Southcentral; a North Slope to Canada 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, the estimates of the cost of gas delivered to Fairbanks and Southcentral are based on the following assumptions:

- The cost is levelized with no inflation from in 2011 dollars.
- The wellhead price of North Slope natural gas is $2.00/Mcf.
- The cost of gas delivered to Southcentral is the cost at the point of delivery to the Southcentral pipeline system; pipeline system tariffs and storage tariffs are additional charges that determine the cost of gas delivered to Southcentral utilities.
- The cost estimates do not account for the costs of financing, royalties, taxes, inflation, or operation and maintenance.[*]
- Also, the cost estimates assume no carbon tax or other carbon-based fee for natural gas.

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

North Slope to Southcentral Pipelines

The Alaska-Stand-Alone-Gas-Pipeline and the Fairbanks Gas Co. Pipeline both propose to ship North Slope gas to Fairbanks and Southcentral.

Alaska-Stand–Alone-Gas-Pipeline

Despite the optimism of the state oil and gas division about finding and producing the Cook Inlet conventional gas resource, the Alaska Legislature authorized developing a plan to transport North Slope gas directly to Southcentral with a hub for Fairbanks. The Alaska Gasline Development Corporation (AGDC) released the final draft plan for the so-called Alaska-Stand-Alone-Gas-Pipeline ("bullet line") in July 2011.[111] The bullet line is not contingent on any other projects under consideration.[112]

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. The 24-inch-diameter pipeline can carry up to 500 MMscfd (million standard cubic feet per day), the lateral line to Fairbanks has a 60 MMscfd capacity.[113] Total estimated project cost is $7.52 billion.[114]

With the current daily demand for gas in Southcentral about 165 MMscfd – 89 MMscfd for electric power, 76 for MMscfd for space heating – additional customers are necessary, because the pipeline must operate nearly at 100% capacity to be financially viable. AGDC expects that 240 MMscfd could be exported as LNG and another 30 MMscfd might be sold to proposed mining operations in Western Alaska.[115] AGDC assumes that these industrial buyers would be willing to negotiate 20-year contracts with the gas producers. Further, assuming Fairbanks were to convert to natural gas for its electric power and space heating the city's daily demand would be about 27 MMscfd and 20 MMscfd respectively. The project schedule has the pipeline in operation by 2019.

Based on its survey of North Slope producers, AGDC has determined the producers are not willing to develop the bullet line because they consider the investment risk/reward ratio unsatisfactory. AGDC therefore concludes the project requires the State of Alaska to fully underwrite project.[116] AGDC proposes the state finance the $7.5 billion project with bonds, which would result in about $12 billion of state-supported debt.[117]

If the pipeline were built, the estimated tariff to Southcentral is $5.71/mmBtu, adding the gas-conditioning cost of $1.42/mmBtu, the estimated cost of gas delivered to Southcentral would be $7.63/mmBtu, if the project were privately financed.[118] If the state finances the project, the estimated cost of gas delivered to Southcentral would be $6.08/mmBtu.[119] Likewise, the estimated cost to deliver gas to Fairbanks is $8.99/mmBtu if the project were privately financed, but would be $6.45/mmBtu with state financing.

Fairbanks Pipeline Co.

The Fairbanks Pipeline Company, a subsidiary of Energia Cura, a Fairbanks energy services company, proposes a 746-mile-long, 18-inch-diameter pipeline from the North Slope to South Central, with a 90-mile-long, 12-inch-diameter lateral line from Livengood Hub to Fairbanks. From Prudhoe Bay to the Livengood Hub the pipeline would carry 250 MMscfd, 50 MMscfd would go through the spur from Livengood Hub, for delivery in Fairbanks, 200 MMscfd would be delivered in Southcentral. The pipeline and spur could be operational by 2018. Estimated cost is $1.1 billion (2010$).[120]

The tariff for gas delivered to the Livengood Hub is $1.68/mmBtu; the tariff from Livengood Hub to Fairbanks is $1.14/mmBtu; the tariff from Livengood Hub to Southcentral is $2.37, gas-conditioning cost is $2.22/mmBtu.[121] Cost of gas delivered to Fairbanks would be $7.04/mmBtu.[122] Cost of gas delivered to Southcentral would be $8.28/mmBtu.[123]

North Slope to Valdez Pipeline

This project is 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 $22.3 billion (2010$).[124] The LNG facility is estimated to cost about $25 billion.[125] The spur line is estimated to cost $750 million.[126] The mainline is a project of Alaska Gasline Port Authority, and the spur line would be a project of Alaska Natural Gas Development Authority.[127]

The estimated tarrif for gas shipped in the main line from the North Slope to Glennallen is $0.1.50/mmBtu, and the estimated tariff from Glennallen to Palmer (Southcentral) is $1.75/mmBtu.[128] Assuming gas-conditioning charge of $1.20 - $1.50/mmBtu; wellhead gas price of $2.00/mmBtu, the cost of gas delivered to Southcentral would be between $6.45 - $6.75/mmBtu.

North Slope to Alberta TransCanada Pipeline

The pipeline proposed by TransCanada would run 1,715miles (2,760 km) from the North Slope to Calgary in Alberta. As initially proposed, the pipeline would be in operation by 2020. More recently, project cost has been estimated to be between $32 billion to $41 billion (2009$).[129]

Alaska Natural Gas Development Authority would build a 300-mile-long, 20-inch-diameter, or 24-inch-diameter, spur line from the main gas pipeline at Delta Junction to Palmer through Glenallen, with a 250 MMscfd-throughput. The spur line is estimated to cost $1.5 billion.[130]

The estimated tariff from the North Slope to Delta Junction is $0.83/mmBtu, the estimated tariff from Delta Junction to Big Lake (Southcentral) is $3.50/mmBtu,[131] and the estimated gas-conditioning charge of $1.20 - $1.50/mmBtu: estimated cost of gas delivered to Southcentral would be between $7.53 - $7.82/mmBtu.

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 August 2011, Golden Valley Electric Association and Flint Hills Resources announced a project to buy North Slope gas – about 20,000 Mcf/day – superchill it to make LNG and truck it about 500 miles to North Pole. The cost is estimated at $180 million, including the LNG plant, 40 trucks, storage, and a regasification facility. Both companies said they would use the gas to replace more expensive fuels. Golden Valley would burn the gas at its North Pole power plant. Flint Hills would burn gas at its North Pole oil refinery. Some extra gas could be sold elsewhere in the Fairbanks area.[132]

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 Golden Valley 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.[133]

The estimated cost of LNG delivered to Fairbanks is $12/mmBtu.[134] *

IMPORTED LNG

Ironically, imported liquefied natural gas (LNG) is likely to be the only supply option if neither North Slope gas nor the Cook Inlet gas resource were to be available at the point Cook Inlet gas reserves cannot meet demand. In fact, Southcentral utilities are reported to be negotiating with potential LNG suppliers to meet a projected deficit in local gas supplies that will begin in 2014 and grow to 10 billion cubic feet a year by 2015 and 47 billion cubic feet a year by 2018.[135]

* There is currently no plan to supply long-term Southcentral gas demand by trucked LNG.

Receiving and Regasification Infrastructure

LNG delivery to Southcentral on a long-term, high-volume basis requires a regasification plant: the regasification options are reconfiguration of the ConocoPhillips-Marathon Kenai plant, a new onshore or near shore, stand-alone facility, and shipboard regasification.[*]

Shipboard regasification, where the regasification system in 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 typically requires that some receiving infrastructure be constructed, including moorings, pipelines, wharfs and storage. Although the construction costs are less than building an onshore regasification facility, when the costs of charting 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.[136] Shipboard regasification seems best suited for markets that require only small volumes and/or an intermittent supply of LNG.

Regardless of whether onshore or shipboard regasification system is deployed. LNG supplied to Southcentral will require increased 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 long-distance, supply-chain. The Cook Inlet pipeline system may also have to be modified and expanded as the gas import volume increases.[137]

Cost of Imported LNG

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

Price of Imported LNG

The report on LNG prepared for the Alaska Gasline Development Corporation estimates that Southcentral utilities can expect to pay about $13.50/mmBtu for imported LNG, which includes shipping to Alaska and which is based on a WTI oil price of $80.[+] [138]

The report on LNG prepared for Alaska Gasline Port Authority prices imported LNG at $10.34, assuming a WTI price of $75.00.

[*] The option of an LNG plant in Fairbanks is discussed in the Alaska Gasline Development Corp. July 2011.

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

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 their LNG cost of production and hence pricing.

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] Depending upon capital cost of the regasification system, AGDC report estimates the tolling fee to be between $0.24 $0.56/mmBu.[*]

- Shipboard regasification, which can range between $50-200 million.[141]
- Reconfiguring the existing LNG export plant into a receiving and regasification plant is estimated to be $62.5 million. [142] The utilities estimate reconfiguring the Kenai plant to be upwards of $150 million.[143]
- New, onshore regasification plant is estimated to cost $400 million.

The cost of LNG delivered to Southcentral would be somewhere between would be $11.00 - $14.00/mmBtu, 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 will be additional charges.

Delivered Cost of Gas-Supply Alternatives

Gas-Supply Option	Cost/mmBtu Southcentral*	Cost/mmBtu Fairbanks+
Cook Inlet Resource	$13.00	N.A.*+
Alaska Stand Alone Pipeline	$7.63	$8.99
Fairbanks Pipeline Co.	$8.28	$7.04.
North Slope to Valdez	$6.45 - $6.75	NA
North Slope to Canada	$7.53 - $7.82	N.A.
North Slope LNG to Fairbanks	N.A.	$12.00
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.
*+ N.A. - Although Fairbanks would not be supplied with gas by this option, gas that would only be supplied to Southcentral could be used to generate electricity to supply Fairbanks, albeit this would probably require transmission system upgrade
** Depending on the tolling fee, this could be as much as $1.50 higher (see below).

VIABILITY OF GAS-SUPPLY OPTIONS

None of the gas-supply options discussed above have gone beyond the feasibility-study stage. Consequently, the gas supply option(s) 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

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. Financial feasibility rests on payback on investment and rate-of-return.[*]

Depending upon which options are financially feasible, they can be then further compared with respect to reliability, permitting, and environmental attributes/impact.

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/mmBtu.[+]

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/mmBtu, the payback is roughly 4 years. Ultimately, the Railbelt market is not large enough to attract the capital investment when compared to other oil and gas investment opportunities.[*+]

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[*] 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.

[*+] This is not to say that no new gas will be produced: if private industry continues to invest in oil exploration and development in Cook Inlet, as is currently the case, whatever gas is associated with oil is likely to be produced and marketed.

NORTH SLOPE

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 finances the Watana project.

Fairbanks Pipeline Co.

Assuming a $1.1 billion investment, and a pipeline utilization factor of 80% during the first several years until Fairbanks space heating and electric-power generation converts to natural gas, payback is about 2 ½ years.

North Slope to Valdez

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. The best-case scenario is a payback of about 3 years. It is unlikely this project is viable if the state finances the Watana project.

North Slope to Canada

With the increase of shale gas resources in North America, Energy Information Agency (EIA) no longer forecasts natural gas prices to be high enough to justify constructing the pipeline before 2035.[144] EIA estimates that the U.S. holds 827 Tcf of technically recoverable unproved shale gas resources, an increase of 480 Tcf from the 2010 estimate. Hence, the EIA doubled its estimates for shale gas production and upped its estimates for total Lower 48 gas production by 20 percent through 2035. Because of those production increases, wellhead prices will stay below $5 per thousand cubic feet through 2022 and increase to $6.53 by 2035.[145] Currently, Canadian natural gas is priced at $2.44/mmBtu (US$) due to a surplus of shale gas.[146]

In light of the oversupply of North American gas, it seems unlikely the TransCanada project is viable; particularly in light of the fact the proponents of the competing pipeline proposal– Denail announced in May 2011 their project was not viable. TransCanada, however, still believes the North Slope to Alberta pipeline is viable.[147]

IMPORTED LNG

In the near term, importing small volumes of LNG to compensate for the expected shortfall of Cook Inlet gas would probably employ shipboard regasification. If Cook Inlet gas supply then declines about 8% annually as predicted, because no Cook Inlet gas resource has been discovered and no North Slope gas is available, the volume of imported LNG would increase to the point where a decision about 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 regasification plant – whether reconfiguration of the existing Kenai LNG plant or a new plant – might be economically justified.

Nonetheless, the tolling fee regardless of the regasification option might be considerably higher than estimated. For instance, if it were assumed a stand-alone facility would 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, which is about $1.50 greater/Mcf than that cited above. Assuming, however, that shipboard regasification will be the initial choice, the tolling fee is assumed to be that estimated above. Still, financing this option, whatever the particular regasification plant, requires considerably less capital than other supply options

The cost of imported LNG delivered to Southcentral to be $11.00-$14.00/mmBtu.

THE VIABLE OPTIONS

Assuming the State of Alaska will fully fund the Susitna project, it seems unlikely for the following reasons that the state would also finance the Alaska-Stand-Alone-Pipeline or the North Slope to Valdez pipeline and liquefaction plant:*

- The debt financing for any one of the projects would probably limit its ability to similarly finance the other energy projects.
- Political opposition might be insurmountable to state financing of more than one large Railbelt energy project.

Assuming the accuracy of the forecast of North American natural gas prices, it is unlikely the TransCanada North Slope to Alberta pipeline will be constructed in the next 20 years.

* The converse would also hold: If the state were to fund the Alaska-Stand-Alone-Pipeline or the North Slope to Valdez pipeline, Watana would be unlikely to be state-financed. Further, either one of the gas-supply projects would supply ample gas to meet all Railbelt energy demand for electricity and space heating.

Therefore the most viable natural gas supply options are:

- Imported LNG.
- Cook Inlet gas resource.
- Fairbanks Pipeline Company North Slope to Southcentral pipeline.[*]

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

VIABILITY OF WATANA

Apart from meeting the goal of providing 50% of the state's electricity from renewable energy sourced, which Watana will surely accomplish, constructing Watana is principally justified on more substantial grounds: [148]

- Resolve the problem of the declining supply of Cook Inlet gas, thereby
- Ensure energy security, and
- Ensure affordable and stable energy pricing for the Railbelt in the long-term, negating the volatility and price escalation of natural gas that would otherwise occur.

As will be explicated below, the claim that Watana will provide energy security because it addresses the problem of reliance on natural gas is fundamentally bogus and the claim that Watana is the solution to the problem of expensive energy is both misleading and misguided.

RAILBELT ENERGY-SECURITY

If Watana were constructed, it will provide only enough electricity to meet 50% of Railbelt's electric utilities' current annual net generation, that is assuming the energy production estimates for the Susitna River project prove to be accurate.

Put another way, the annual electric output from Watana will provide less than 25% of the total current Railbelt energy provided by gas and electric utilities for electric power and space heating.

Current demand for natural gas by the utilities for electric loads and space heating is about 70 Bcf annually. If Watana actually generates 300 MW of energy on average, then about 21 Bcf of natural gas that would otherwise be burned in Chugach Electric's gas-fired turbines will not be necessary, but at least 49 Bcf of natural gas will still be required.

Therefore, Watana does nothing to address the problem of finding new sources of supply as Cook Inlet gas reserves continually and inevitably approach zero. In other words, the problem of finding new gas supply is the same with or without building Watana.

A Susitna River hydropower dam would further diversify the Railbelt's energy supply, but this attribute is important only in the context of reliability. In other words, if

Watana were not constructed, to what degree would electric-power consumers be more vulnerable to loss of service?

- If new gas supply were to come from the Cook Inlet resource, the possibility of gas supply disruption for any reason is so remote as to be negligible.
- If the new gas supply were to come from the North Slope, there is 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 pipeline failure.
- If imported LNG is the future gas supply, disruption to the supply chain is certainly possible and can be anticipated, but also presumably there will be sufficient storage to ensure deliverability and reliability.

Certainly, if Watana were constructed and operating, and gas delivery were to be interrupted long enough to cause a shortage, the existence of Watana in the generation portfolio will indeed have increased reliability of service for the electric utilities. However, as it is unlikely that any of the future gas supply alternatives would be disrupted to that extent or for significant duration, paying $5 billion for a dam insurance policy is neither prudent nor reasonable.

RAILBELT ENERGY-AFFORDABILITY

If the incremental reliability afforded to the Railbelt electric-power system by Watana does not justify the project, then surely the promise the dam is sure to ensure affordable energy for the Railbelt justifies the project and state financing. If the overall price of energy in the Railbelt will be significantly lower with Watana than without, then the price of electricity from Watana must be considerably less than the price of electricity that will be generated by gas.

Cost of Electricity

Flowing water “fuels” the generator with its kinetic energy to generate electricity, natural gas fuels the generator with its heat energy, which is released through the chemical process of combustion.

The cost of electricity produced at the generating station can be calculated as cents per kilowatt-hour ($0.00/Kwh) at the “busbar”. The busbar cost is the sum of the capital cost of generators, operating and maintenance cost of the generating plant and fuel cost divided by the total annual electric generation in kilowatt-hours; transmission and distribution costs are not included. For the purpose of comparing the busbar costs from the viable gas supply options with one another and Watana, Chugach Electric’s busbar cost will be the reference cost. CEA's 2006-generation plan forecasts that the cost of electricity generated by its gas-fired plants in 2015 will be $0.77/Kwh. 2015 is the year the combined-cycle, 183-MW Southcentral Power Plant (SCP) will be on line.[*] [149]

- The power plant will decrease CEA's average fuel consumption system wide from 10.7 Mcf per megawatt hour to 8.25 Mcf per megawatt hour.
- Overall efficiency of CEA natural-gas generation system wide will increase from 31% to 40%.
- Natural gas is estimated to be $6.79/mmBtu average cost.
- Total annual fuel cost will decline with SCP, but total capital and operating costs will increase, therefore, the busbar cost will increase from $71.00/Mwh (megawatt-hour) currently to $77.00/Mwh, or $0.077/Kwh.
- Capital, operation, and maintenance costs account for $0.021/Kwh, while the fuel cost is $0.056/Kwh (assuming gas price of $6.79/mmBtu).

BUSBAR COST OF GAS-SUPPLY ALTERNATIVES

The cost/price of the viable gas-supply alternatives has been estimated at the point of delivery to the Southcentral pipeline system. When determining the cost of electricity from the viable gas-supply options, the cost of transportation from the point of entry to the Southcentral pipeline system to the gas-turbine generator must be include.

Cook Inlet Resource

If private investment does materialize to find and develop the Cook Inlet gas resource, the price of gas delivered to the Southcentral pipeline system will be at or slightly higher than the price of LNG or about $13.00/mmBtu, as estimated above. Adding the $0.50/mmBtu pipeline system tariff and ~$0.25/Mcf storage tariff,[+] the cost/price at the Chugach burner tip would be $13.75/mmBtu. Busbar cost is $0.13/Kwh

Fairbanks Pipeline Co.

The cost of North Slope gas delivered to Southcentral via the Fairbanks Pipeline Co. pipeline is estimated to be $8.28/mmBtu, adding $0.50/Mcf Southcentral pipeline system tariff and $0.25/Mcf storage tariff, the cost/price at Chugach burner tip is $8.98/mmBtu. Busbar cost is $0.09/Kwh.

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

[+] The tariff from the new Cook Inlet storage facility is estimated to be $0.75/Mcf and will be charged only to the gas that is actually stored; for purpose of this analysis, the tariff is allocated to all the gas; assuming 1/3 of gas of the annual volume of gas will be stored , then allocating the tariff to all gas is $0.25/Mcf.

Imported LNG

If the average cost of imported LNG delivered to Southcentral is about $13.00/mmBtu, adding a $0.50/Mcf pipeline system tariff plus a $0.25/mmBtu storage tariff, the cost/price at the Chugach burner tip is $13.75/mmBtu, busbar cost is $0.13/Kwh.

WATANA BUSBAR COST

Given the estimate of $4.5 billion to construct the Watana power dam,* the busbar cost is $0.13/Kwh.[150]

Therefore, the cost of electricity at the Watana busbar during the first few years is about the same as that estimated from as from Cook Inlet Basin resource and imported LNG, but more than a kilowatt hour from North Slope gas transported by the Fairbanks Pipeline Co.

Nonetheless, given the that gas prices are likely to increase significantly during the next fifty years, regardless of which gas supply alternative is implemented in the Railbelt, hydroelectricity from Watana is likely to be cheaper on a levelized basis than any of the considered gas-supply options, because the state has priced its Susitna River water, the "fuel" for the hydropower plant, at $0.00; whereas gas has a market price, and is therefore volatile and likely to increase over time.

Watana–Effect on Energy Cost and Supply

Even though Watana will initially decrease the amount of gas use, which would likely delay the construction of the stand-alone regasification facility by a few years or more if imported LNG were the future gas-supply alternative, the dam will otherwise have no ameliorative effect on the net capital investment required to implement any of the three viable gas options of finding and producing the Cook Inlet resource, importing and regasifying LNG, or piping North Slope gas to the Railbelt region.

Therefore, given that Watana would provide no more than 50% of electricity at a stable price for the life of the project, Watana will dampen the volatility of natural gas pricing for but will have no effect on natural gas pricing. Consequently, Watana will make Railbelt energy somewhat more affordable than it would have been otherwise. For instance, if natural gas prices were to double during the first 50 years of the hydropower project, the monthly Railbelt energy bill of most consumers who rely on gas for space heating will be about 25% lower than it would have been without the project. Yet, the State of Alaska's contention the Watana project will ensure affordability of energy in the Railbelt is misleading as Watana would not have any effect militating against either volatility of natural gas pricing or increase in natural gas price over time.

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* This estimate is certainly too low; in addition it does not include the cost of transmission upgrade, which is estimated to cost several hundred million dollars.

In its authorization of the Alaska-Stand-Alone-Gas-Pipeline feasibility study, the State of Alaska has determined that

> Completion of construction of an in-sate natural gas pipeline that will provide significant direct benefit to the people of the state at the earliest possible date . . . its 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. [*] [151] (emphasis added)

Given the capital cost for this pipeline is about 7.5 billion and the pipeline is feasible only if the State were to finance the entire amount, and given the state's conviction that the private sector will not develop an new in-state, natural-gas supply to replace the declining Cook Inlet reserves, then the state would seem sworn to constructing the pipeline to assure the future gas supply for the Railbelt. Yet, for the reasons enumerated above, it is unlikely the state will be able fully finance Watana and the Alaska-Stand-Alone-Pipeline. It is ironic state financing of Watana might significantly impair the viability of state financing of the Alaska-Stand-Alone-Pipeline. Thus, building Watana arguably may preclude at least one gas-supply option with potentially the lowest long-term gas cost.

Consequently, if the state proceeds with Watana, it would not accomplish either one of its stated goals: energy affordability or a secure gas supply. In this context, the better choice is the pipeline, because that project will ensure a sufficient supply of energy for both electric-power generation and space heating in the Railbelt, even if it were unable to ensure stable, non-volatile gas pricing. The Watana project will neither supply sufficient energy to the Railbelt nor prevent gas price volatility and increases. Of course, it cannot be ruled out that the State of Alaska decides to fund both Watana and the Alaska-Stand-Alone-Gas-Pipeline, which would be at least $18 billion, including the cost of financing. Even this amount of funding, however, could not ensure energy affordability. From the perspective of energy security and affordability, Watana cannot be regarded as a viable project.

This begs the question of whether there might be another option that would achieve the state's two goals of affordability and secure supply: A state-financed and operated Cook Inlet gas supply would seem to do so.

[*] This refers to developing new Alaska gas supply; the private sector can be counted on to import LNG if necessary.

COOK INLET GAS—STATE-FINANCED

As cited above, the State of Alaska has determined that a secure long-term supply of natural gas is necessary to the socio-economic well-being of its citizens residing in the Railbelt and the private-sector investment to ensure a secure gas supply is likely not forthcoming. The optimal path, then, is for the State of Alaska to find and produce its own Cook Inlet gas resource.

RATIONALE

Just as water in the Susitna Basin is a public-trust resource, so is the state-owned gas resource in the Cook Inlet Basin. Certainly, the development of the Cook Inlet gas resource to supply Railbelt utilities is congruent with Alaska constitution's admonition of to utilize its resources for the maximum benefit of Alaska residents. Alaska Energy Authority (AEA) has concluded $4.5 billion in state financing for the Watana hydropower dam is in the public interest. The same finding should be made with respect to the state's Cook Inlet gas resource.

If the State of Alaska were to similarly finance, own, and produce 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, exploration, development and production of gas from new Cook Inlet fields can be done in stages. While the cost of finding and developing the 7.5 Tcf of the Cook Inlet gas resource is estimated to approximately $18 billion, presumably the resource would be developed in blocks: a 20-year block at current demand would be about 1.5 Tcf at a cost of about $3.6 billion. The revenues from this supply would be recycled to finance the next multi-year supply, and so on. Further as more cost-effective, less-impact energy sources become available, investment in developing more gas can be appropriately scaled.

COST OF ENERGY

In this scenario state-owned gas is assigned zero monetary value – just as water for Watana generators is priced at $0.00. Therefore, as is true of Susitna, the cost of gas from a state gas supply to the electric utility as well as the gas utility would be the actual cost of production, transportation, storage, and cost of operations and maintenance.

The cost to find and develop new supplies of Cook Inlet gas is estimated to be $2.40/Mcf at the wellhead; additional costs to deliver to the utility are the tariff to pipe gas from new wells to the existing pipeline system ($0.15/Mcf), pipeline system tariff

(~$0.50/Mcf) and storage tariff (~$0.25/Mcf), for a total price of $3.35/Mcf.* The busbar cost is $0.047/Kwh.
Further, if financing development of Cook Inlet Basin gas resource is equivalent to financing Watana, for which the state proposes to a grant at least $2.25 billion and reduce the cost of electricity at the busbar by 50% to $0.63/Kwh, [152] then an equivalent grant will reduce the cost of gas delivered to the utilities to $1.13/Mcf. during the first 20 years. The busbar cost is $0.032/Kwh.

Further if the state were to invest the $2.4 billion estimated to find and develop up to 1.5 Tcf from new gas fields, the full investment is recovered during the 20-year life of the gas field at current demand, which would be used to develop the next supply segment

THE OPTIMAL PATH

Below is a comparison of the Railbelt energy-supply alternatives that elucidates state-owned Cook Inlet gas supply is the optimal path to achieving the state's two goals of affordability and secure supply:

Supply Security

Different factors affect the amount and availability of the energy-source from each energy-supply alternative.

North Slope

The North Slope gas reserve of about 34 Tcf assures supply. [153] As this option relies on one pipeline, security of supply is slightly more vulnerable than supply from Cook Inlet. If demand for gas increases above the pipeline capacity, as might be the case for the Fairbanks Pipeline Co. pipeline, another source of supply would be required.

Imported LNG

An oversupply of LNG in the Pacific region is forecast during the next several years as new LNG terminals come online mainly in Australia and Canada. LNG is typically contracted on a long-term basis often with 25-year, take-or-pay contracts.[154]

Nonetheless, supply chain risk exists, albeit a historically low risk, including slow-down or shutdown in gas-field production and/or export terminal liquefaction, LNG-transport delays, and regasification equipment failure. Whether the risk is significantly greater than risks associated with other supply options is unlikely, but management of the risk

*This price does not include operations and maintenance.

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.

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 are obstacles to access certain areas.

Even if the Cook Inlet gas could be sold to the local market at a premium above the imported LNG price due to the reliability of supply, if the producers were to find an export market to further increase their rate of return – as has been the case during the past 40 years – then the Cook Inlet gas supply could be rapidly depleted, leaving the Railbelt utilities with the same problem of gas shortfall. The state's recently proffered financial incentives to develop and produce Cook Inlet gas did not require the quid pro quo of stipulating where the gas can be marketed or establishing a price ceiling.

Cook Inlet-State AK

Even with state-owned production, access to some areas will remain an issue. Extant leases might revert to the state through default, or the state might buy back leases. Since the market 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 blocks, allowing new blocks of supply to be financed by revenues from the existing production.

Watana

Water for hydroelectric generation is available in known quantity and timing. Typical risk to reliability and security of energy-source supply – albeit low – is drought, climate change, and dam failure. Access to land and water is not an issue.

Permitting and Construction

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

North Slope

Fairbanks Pipeline Company contends it can have the pipeline in operation about three years from the time design and permitting commences. [155]

Imported LNG

The typical Greenfield regasification terminal in the United States is estimated to take over five years from initial permit application to receiving tankers. Presumably if the Kenai LNG plant were to be reconfigured, total construction time would be less than a new stand-alone regasification terminal. Under current regulations, permitting can take from one year (offshore terminals) to over two years (onshore terminals), assuming minimal resistance and a well-coordinated permitting process.[156]

Cook Inlet-Private Sector

Permitting is required for drilling, production wells and 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.[157]

Cook Inlet-State AK

Presumably subject to same permits as “Cook Inlet-Private Sector” option.

Watana

Licensing and permitting will take from 7 to 10 years and construction several years.[158]

Impact on Local Environment

Local environmental impact is the direct and indirect impacts to land, water and air in and surrounding the project area.

North Slope

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. Given minimal construction activity in marine waters, which may entail mooring, a receiving pipeline wharf expansion, and minimal on-shore facility construction, including storage, pipeline modification/expansion, compressor station, there is unlikely to be any significant impact to local environment. In fact, this supply alternative has the least impact of any.

Cook Inlet-Private Sector

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.

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.[159] 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 gas associated with oil reservoirs; still, the volume of produced water increases as the gas reservoir is depleted. Produced water that escapes into the marine environment is toxic to marine life. Cook Inlet has already experienced significant discharge of produced waters from existing oil and gas production.

Cook Inlet-State AK

Same as private industry.

Watana

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

In general, of all the renewable-electric, power-supply systems, hydropower has the largest the environmental footprint not only spatially, but also ecologically because freshwater ecosystems are usually the areas of greatest biodiversity and productivity.[160]

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

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 AK

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.

Watana

The actual conversion of kinetic energy from flowing water to electric energy results in no greenhouse-gas emissions. However, the following facets of the hydropower project either are or may be sources 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 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 melt permafrost in submerged land releasing carbon that is stored in the permafrost layer.
- 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.

If the total greenhouse-gas emissions over the life of the hydropower project are relatively insignificant, it can be posited Watana is eliminating the greenhouse-gas emissions from the 21 Bcf of natural gas that would otherwise have been combusted each year to generate the 2,600 gigawatt hours the hydropower project provides for the Railbelt. This conclusion, however, is not necessarily warranted, as it assumes the displaced 21 Bcf will not be used somewhere else. For instance, if private companies do develop and produce gas from new Cook gas fields, then the "displaced" gas could be exported as LNG. This might also be the case with State of Alaska ownership, if gas sales were not restricted to Southcentral/Railbelt utilities.

Yet, even if it were granted that the Susitna River power dam will displace up to 21 Bcf of natural gas annually, the question arises: are the environmental impacts that are avoided by eliminating the emissions from 21 Bcf of natural gas equal to or greater than the impacts to the Susitna watershed from the construction, operation, and decommissioning of the hydropower project?

The scientific conclusion that rising concentration of greenhouse gases in the atmosphere increases the rate at which the atmosphere and planet's surface warm is unassailable. In turn, global warming results in discrete, discernable impacts to all local terrestrial and marine environments worldwide. These impacts are inflicted temporally and spatially through climate change and severe weather events that are causally associated with climate change – weather events occur rapidly in time, over limited surface areas, whereas climate change is persistent and affects much greater surface area.

For instance, the effect on a local watershed environment, such as the Susitna River watershed, from severe weather events and climate change can 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 same adverse changes caused by a power-dam, especially those with as large and multi-faceted a footprint as Watana. Therefore, constructing and operating Watana does not attenuate but rather exacerbates the environmental impacts of global warming.

Further, the impact of greenhouse-gas emissions on local environments from burning the 21 Bcf of gas that Watana might displace yearly is too small to detect: 21 Bcf is 0.008% of the 2500 Bcf burned worldwide each year. This is not to say there are no incremental impacts from the addition of 21 Bcf-worth of greenhouse-gas emissions, but rather these impacts are problematic, because they are not easily discernable or quantifiable, whereas, the impacts from a Watana hydropower dam are readily discernable and usually quantifiable.

Any justification of the Watana project on the basis of its assumed low greenhouse-gas emissions is to trade problematic impacts for definite ones. This is an illogical "destroy-the-environment-to-save-the-planet" calculus.

The only way to reduce the harm to local environments from global warming is through zero or low-emission energy source and power-supply technologies that do not themselves harm the environment. In other words, if the goal is to reduce 21 Bcf worth of greenhouse-gas emissions, 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.

Economic Impact

A rigorous economic-impact analysis weighs both benefits and costs for each option, but such an analysis is beyond the scope of this paper; 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. Watana would undoubtedly create the most construction jobs, followed by the Fairbanks Pipeline Co. After construction, the operation of the projects will all provide full-time direct employment, albeit the number of jobs will vary among the projects. 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.

Perhaps the most salient economic impact when assessing the case for a Susitna River hydropower dam is impact on economic activity in the Railbelt region from the various energy-supply alternatives.

North Slope, Imported LNG, Cook Inlet-Private Sector

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

Cook Inlet-State AK

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 in its generation plan. By 2020, when 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.
- However, if the state produced the 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 would be paid to private producers as described above. Gas price 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 "saved" due to lower price, 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, which would otherwise amount to about $32 million.[*161] 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.

Watana

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 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 have annual revenues from Watana generation of $164 million, which will be used to repay the state subsidy.

Hence, the total annual Railbelt "energy bill" with a Susitna River dam will be $475 million – about $55 million more than if all the energy were supplied by natural gas, albeit this difference will decrease if gas price increases, which is likely if the gas supply is privately owned.

Of course, the state does not receive tax revenue or royalty payment from Susitna, and if the 21 Bcf of natural gas displaced by Susitna hydropower were not 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; royalty payments are reported by region.

COMPARING SUPPLY OPTIONS

	NORTH SLOPE	IMPORT LNG	CI-PRIVATE SECTOR	CI-ALASKA OWNED	WATANA
SUPPLY-SECURITY RELIABILITY	HIGH	MODERATE	LOW	HIGH	HIGH
PERMITTING ISSUES	MODERATE	MODERATE	MODERATE	MODERATE	HIGH
ENVIRONMENTAL IMPACTS-LOCAL	LOW	LOW	MODERATE	MODERATE	HIGH
ENVIRONMENTAL IMPACTS-GLOBAL	MODERATE	LOW	MODERATE	MODERATE	LOW(?)
ECONOMIC BENEFIT	MODERATE	LOW	LOW	HIGH	MODERATE

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 premature.

This analysis concludes that Watana does little to ensure or even enhance reliability of Railbelt energy supply, has little effect on energy affordability and no impact on gas price volatility or gas pricing.

Further, Watana detracts from solving the problem of ensuring a long-term natural gas supply. 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 Alaska Railbelt Regional Integrated Resource Plan (RIRP), commissioned by Alaska Energy Authority, assessed various Susitna River hydropower projects as well as other hydropower projects, notably the Lake Chakachamna project, but does not conclude that any should be constructed. As explained in the draft plan,

> The selection of specific resources requires additional and more detailed analysis . . . [the] RIRP, consistent with all integrated resource plans, should be viewed as a "directional" plan. In this sense, the RIRP identifies alternative resource *paths* that the region can take to meet the future electric needs of Railbelt citizens and businesses; in other words, it identifies the *types* of resources that should be developed in the future. [162]

The RIRP provides data and analysis to inform energy policy and planning, the RIRP, however, is not an energy plan nor does it establish state policy.[163]

Yet, shortly after the release of the draft RIRP in December 2009, the legislature appropriated $10 million to Alaska Energy Authority for licensing and permitting of a large hydro project. In response to the appropriation, AEA in November 2010 recommended the Watana hydropower dam project.

AEA's justification for its recommendation is the project is "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 project that can provide the required amount of electricity by 2025 is a Susitna project. [164] The Palin administration promoted the "50%-by-2025" goal in 2009, which was ratified by the legislature in 2010: HB 306 states "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."[165]

The legislature's *intent* has apparently become the primary driver in Railbelt energy planning. Unfortunately, the "50%-by-2025" interferes with appropriate energy planning to the extent it is used to rationalize projects that would otherwise not be built. 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), arguably the major prerequisite for achieving "maximum benefit."

The "50%-by-2025" is bad policy to the extent it obviates an analysis of alternatives. The premise of the 50%-by-2025 policy is renewables provide affordable energy at stable prices over time with minimal environmental impact.

In most cases, renewables will provide the most affordable energy at stable prices over time with minimal environmental impact. But this presumption needs to be tested by comparison to other viable alternatives. Yet, rather than first complete a comprehensive analysis of the most cost-effective energy-supply, energy-efficiency, and energy-conservation options, the State of Alaska hastened to pick various projects – from Susitna to TransCanada – believing one or another will prove to be the cure for the Railbelt's energy ailment.

In fact, because the proposed Susitna River power project will provide no more than 25% of the total Railbelt utilities' annual energy for electric power and space heating, the Watana dam will not prevent energy-price volatility nor prevent the price of energy for electricity and space heating from rising. Before the state decides to spend at least $70 million to prepare an application for a Susitna River dam license, further evaluation of other viable alternatives is called for.

Based on this analysis, there are compelling grounds for the state to invest in finding and producing its own Cook Inlet gas resource. The state could also choose to finance the Alaska-Stand-Alone-Pipeline. Of course, imported LNG does not require any state subsidy. Nonetheless, based on these options, there is no reason to build Watana for at least 50 years or more, if ever. Jeopardizing the salmon-bearing Susitna River watershed should be the alternative of last resort.

* The life cycle of a power dam 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.

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