An Appraisal of State-Sponsored Solutions to the Railbelt Energy Supply and Affordability Problem

Jan Konigsberg
Alaska Hydro Project
jan@hydroteform.org

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NOMENCLATURE AND GLOSSARY

AEA – Alaska Energy Authority
AGDC – Alaska Gas Development Corporation
AIDEA – Alaska Industrial Development and Export Authority
Bcf – billion cubic feet (natural gas)
CEA – Chugach Electric Association
DNR – Alaska Department of Natural Resources
FERC – Federal Energy Regulatory Commission
FNG – Fairbanks Natural Gas Co.
GHG – greenhouse-gas
GVEA – Golden Valley Electric Association
GW – gigawatt (1,000,000,000 watts)
gWh – gigawatt-hour
HEA – Homer Electric Association
IGU – Interior Alaska Natural Gas Distribution Utility
LNG – liquefied natural gas
KW – kilowatt (1,000 watts)
kWh – kilowatt-hour
Mcf – thousand cubic feet (natural gas)
MEA – Matanuska Electric Association
ML&P – Anchorage Municipal Light and Power
MMBtu – million British thermal units
MMcfd – million cubic feet per day (natural gas)
MW – megawatt (1,000,000 watts)
mWh – megawatt-hour
RCA – Regulatory Commission of Alaska

SEA – Seward Electric Association

USGS – United States Geological Survey

Tcf – trillion cubic feet (natural gas)
SUMMARY

- With production from Cook Inlet natural gas fields in decline, the State of Alaska has been implementing various initiatives to address the problem of Railbelt energy supply and affordability: 1) financial incentives for finding and developing new Cook Inlet gas fields; 2) a pipeline to bring North Slope gas to market; 3) an LNG supply for Fairbanks; and 4) a hydroelectric dam on the Susitna River.

- Cook Inlet gas provides 75% of Railbelt energy for electric power generation and heating. The existing gas fields will run out of gas around 2040. The rate of depletion has been slowed by new and reworked wells; but as a result, the wholesale price of natural gas has more than tripled since 2000 from less than $2.00/Mcf to about $6.50/Mcf.

- The state has subsidized the Cook Inlet oil and gas industry with $1.8 billion in tax relief—of which nearly $1 billion has been refundable credits—most of which the state has paid since 2006. Using different tax credits has allowed oil and gas companies to be reimbursed as much as 65% of their Cook Inlet exploration and development expenses.

- The favorable tax regime has served primarily to increase profitability of producing gas in existing fields, yielding a 30% rate-of-return (26% without the tax credits); but has not resulted in developing the natural gas resource, which geologists estimate to be 15 trillion cubic feet.

- With lower crude oil prices, major increase in LNG supply, but lower LNG demand in Asia, the feasibility of a North Slope gas pipeline will remain uncertain for the foreseeable future.

- Unless either the Cook Inlet gas resource is found and developed or a North Slope pipeline is built, the state has no other project to ensure a long-term, affordable supply. The dam project is a distraction from solving the problem of ensuring a long-term, natural gas supply, as the dam would provide only 25% (19 Bcf) of current Railbelt energy demand.

- Since the industry has decided that finding and developing the Cook Inlet natural gas resource is not competitive with other investment opportunities, the state might choose to assume greater responsibility and risk for developing this gas resource—an option justified by the same assumptions and principles underlying its current energy supply initiatives.

- None of the state’s initiatives—with $2.8 billion allocated so far for their implementation—would solve both energy supply and affordability problems.
Based on available information, the cost of finding, developing, and producing the Cook Inlet natural gas is about $1.15/Mcf. When compared to providing energy from the proposed Susitna River hydropower project, natural gas would save Railbelt ratepayers $35 billion (2014$) over 50 years, if the state assumed the risk in the same manner as it is proposing to do to develop Susitna River hydropower. This would provide the greatest economic benefits for the least cost with the least environmental impacts.
An Appraisal of State-Sponsored Solutions to the Railbelt Energy Supply and Affordability Problem

PURPOSE

Since 1980, the State of Alaska has shared responsibility with local utilities for energy supply and affordability in cities, towns, and villages outside the Railbelt region; mainly by financing hydroelectric dams, subsidizing diesel-fuel costs, and providing alternative-energy grants and loans. For the past 10 years, concern about Railbelt energy-supply and affordability has claimed the state’s attention as well.

Cook Inlet natural gas is the major energy source for Railbelt electric-power generation and heating; however, for the past several years, gas supply has barely kept up with demand. New wells in existing fields have increased gas reserves, but the cost of drilling to maintain supply has increased the price of gas. While new wells have extended the life of existing gas fields, they do not solve the problem of a long-term energy supply for the Railbelt.

In 2008, continuing uncertainty about future energy-supply prompted Alaska Energy Authority (AEA) to contract for an integrated-resource plan for the Railbelt. The integrated-resource plan has served as the springboard for various state-sponsored Railbelt energy supply and affordability initiatives, which are now being implemented.

The purpose of this review of the state’s energy-supply initiatives is to ascertain their potential to achieve the stated goals of energy security and affordability in light of their implementation thus far. After reviewing the state’s initiatives, this report examines the option of the state developing and producing natural gas from its Cook Inlet resource to supply the Railbelt.

BACKGROUND

The Railbelt is the region served by the Alaska Railroad from the Kenai Peninsula to Fairbanks. The region is electrically connected by a transmission grid shared among six independent electric utilities. The region’s one major gas

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* Hydropower Reform Coalition provided funding for this report; Alaska Hydro Project is solely responsible for the report.
‡ This paper reviews only current state-sponsored initiatives.
utility, Enstar, serves only the southern and central portion of the Railbelt, which includes the Kenai Peninsula, Anchorage Bowl, and the Matanuska-Susitna Valley.

Natural Gas Supply

About 75% of the Railbelt’s energy for electric-power generation and heating is supplied by natural gas. Railbelt utilities use about 70 billion cubic feet (Bcf) per year—approximately 34 Bcf for heating, and 36 Bcf for electric-power generation. The gas comes from 28 Cook Inlet gas fields, which have been in production since the 1950s and 1960s. Most of the gas fields are onshore and were discovered when the companies were exploring for oil.

Gas production from these aging Cook Inlet fields began to decline around 2000; prompting concern among Railbelt utilities about the uncertainty of supply. The gas producers at the time—ConocoPhillips, Unocal, Chevron and Marathon Oil—were drilling just enough wells in the existing fields to meet contract obligations, many of which were due to expire before 2010. So, between 2001 and 2009, the companies drilled 128 wells, completing 105 wells, and adding 563 billion cubic feet (Bcf) to gas reserves. Once their contracts ended, the utilities would not be assured of sufficient supply over the long term. In 2010, Enstar—for the first time ever—no longer had firm contracts for 100% of its forecasted need. Since then Enstar and the other electric utilities have been able to sign only short-term contracts.

For the past several years, there has been continuing uncertainty about just when supply from the existing fields will fall short of demand, because it is not known whether enough new wells will be drilled to access the remaining gas in the legacy field that cannot be produced from the old wells.

The Department of Natural Resources (DNR) predicted that if no new wells were drilled after 2010, supply would fall below demand by 2012. DNR calculated 187 new wells would need to be drilled between 2011 and 2020 to maintain supply. Further, enough new wells would have to be drilled every year to produce at least 31 million cubic feet per day (MMcfd) each year to offset the declining production from all the existing wells. If new production did not meet this goal, DNR predicted supply would fall short of demand by at least 5.1 Bcf, but possibly as much 11.4 Bcf, as early as 2014 or as late as 2020.

Before their contract obligations expired, the Cook Inlet gas producers announced they were not willing to invest either in new wells, (other than to meet existing contract obligations), or finding and developing new Cook Inlet gas fields. Marathon Oil explained at the time “the project economics and market uncertainties make it difficult for projects to compete effectively for finite money.

Except for a miniscule amount of gas that is liquefied and trucked to Fairbanks, Cook Inlet gas is used only in the southern half of the Railbelt from Homer to Matanuska-Susitna Valley.
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.” Compared to the profitability of gas from older wells, the rate of return from new wells is apparently not competitive with other investment opportunities. So, the majors put their Cook Inlet gas properties up for sale. By 2012, Union Oil, Chevron, and Marathon had sold their Cook Inlet assets to Hilcorp Alaska LLC, and in 2015, ConocoPhillips announced it would sell its remaining Inlet asset, the Beluga gas field on Cook Inlet's west side.

The legacy gas fields have been purchased by smaller companies, the so-called “independents.” The independents, particularly Hilcorp Alaska LLC, have invested in reworking old wells and drilling new wells in the legacy gas fields; adding enough reserves to meet Railbelt demand through at least 2018. Evidently, the profitability of such investment, while not sufficient for the majors, is good enough for Hilcorp and other independents.

DNR’s most recent estimate (September 2015) of remaining proven gas reserves from the legacy Cook Inlet fields gas supply is 711 Bcf, with an additional 472 Bcf of probable reserves that would be recoverable by mitigating well problems and increasing investment in existing fields. Even if all wells necessary to tap the remaining reserves were to be drilled, DNR forecasts the 28 existing fields will all be pumped dry sometime in the early 2040s. Therefore, finding and developing new gas fields is necessary to ensure a long-term supply of natural gas from Cook Inlet.

**Natural Gas Price**

Declining gas supply has resulted in the problem of higher natural gas prices.

Even as the Railbelt population, particularly Anchorage, grew rapidly in the 1970s, 1980s and into the 1990s, the wholesale price of gas remained relatively stable—less than $2.00 per thousand cubic feet (Mcf)—due to the enormous supply and low cost of production. With investment in new wells, wholesale gas prices began to rise.

In 2001, the Regulatory Commission of Alaska (RCA) approved a contract between Unocal and Enstar that indexed gas price to the Henry Hub gas market in the continental U.S. Consequently, as gas prices in the Lower 48 climbed, the Alaska gas price also increased, with Enstar paying $8.76/Mcf in 2009—the highest ever. In response to this particular price hike, RCA rejected its Henry Hub indexing formula, deciding instead to index gas price to the broader North American gas markets. As North American gas prices declined due to the shale-
gas boom, Enstar’s gas-purchase price fell, averaging $6.67/Mcf from 2010 through 2013. \(^{12}\)

In 2012, the state consented to Hilcorp’s acquisition of Marathon Oil’s gas fields, which gave Hilcorp control of 70% of Cook Inlet gas reserves. The state’s consent required Hilcorp to agree to price ceilings through 2017—$6.60/Mcf in 2013 increasing to $7.72/Mcf in 2017; after which there is no restriction on pricing. \(^{13}\)

**THE STATE-SPONSORED INITIATIVES**

Current state initiatives described below are Cook Inlet tax-regime, North Slope pipeline, Fairbanks LNG, and Susitna River hydropower.

**Cook Inlet Tax-Regime**

Finding new gas fields in Cook Inlet is crucial to providing a long-term, natural gas supply for the Railbelt. Because the Cook Inlet gas resource would be geographically the closest potential source of future supply to the Railbelt; would utilize the existing pipeline system and would be “dry” gas that does not require any further treatment (as would gas from the North Slope); gas from Cook Inlet would presumably be the most economical gas to develop.

The United States Geological Survey (USGS) estimates the Cook Inlet conventionally recoverable gas resource to be 15 trillion cubic feet (Tcf). \(^{14}\) The gas resource is gas assumed to exist based on geologic knowledge and theory, but has not been actually discovered. Geologists believe most of the gas resource is located offshore in upper Cook Inlet and is not associated with oil; as was the case with the already developed gas fields, most of which are onshore. \(^{15}\)

Notwithstanding their willingness to invest in existing gas fields, the independents are not willing to invest in finding new gas fields. Most independents do not have significant capital reserves, and their investment in exploration is confined to finding oil, which is more profitable to develop than new gas fields, especially in Cook Inlet. \(^{16}\) Bearing this in mind, in 2006, the legislature changed the Cook Inlet tax regime to incentivize oil and gas exploration, development, and production. This change instituted tax credits for all oil and gas expenditures—exploration, development of new fields, reworking old wells, and drilling new wells in existing fields. The credits apply regardless of whether or not the expenditure results in taxable production of either oil or gas. In other words, even when a company has no tax liability because no production resulted from its investment, it receives the credit as a cash payment. \(^{17}\) In 2010, the legislature

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\(^{12}\) In 2004, the legislature reduced the royalty rate to stimulate Cook Inlet oil production.
approved a $25 million tax credit for the first offshore Cook Inlet well drilled into the Mesozoic strata; this credit also applies to both oil and gas exploration.\textsuperscript{18}

The legislature’s rationale for changing the Cook Inlet tax-regime is that “since explorers and developers had no tax liability, there was no incentive for them to embark on those costly projects in the state. By instituting a rebate system, the state was investing in exploration and development projects with the goal of having those projects reach production. Once in production, and after the operator accrued a tax liability, the state would begin to see a return on its investment.”\textsuperscript{19}

The legislature believed new gas fields would be discovered as a byproduct of oil exploration, so the legislature intended the tax credit to increase investment in oil exploration, which in turn would presumably result in finding gas associated with oil.\textsuperscript{20} However, since the offshore gas resource of Cook Inlet is supposedly not associated with oil, it is unlikely that the legislature’s strategy of incentivizing oil exploration in order to find natural gas will bear fruit.

\textbf{North Slope Gas Pipeline}

North Slope gas reserves would provide a secure supply to the Railbelt for at least 100 years.

In 2011, as a hedge against the industry failing to find and develop the Cook Inlet gas resource, the legislature authorized the Alaska Gasline Development Corporation (AGDC) to manage the Alaska-Stand-Alone-Pipeline (ASAP) project—a $9.9 billion (2014$), 36-inch-diameter pipeline from the North Slope to a LNG plant at tidewater in Southcentral.\textsuperscript{21} AGDC determined North Slope gas producers would not be willing to invest in the pipeline due to its high-risk to low-reward ratio, and concluded it would be necessary for the State of Alaska to finance, construct, and operate the project.\textsuperscript{22}

Then, in 2014, the legislature agreed to become an equity partner with ExxonMobil, British Petroleum, ConocoPhillips, and TransCanada\textsuperscript{†} in the Alaska LNG pipeline—a 42-inch-diameter pipeline from the North Slope to a LNG plant at tidewater costing up to $65 billion (2014$).\textsuperscript{‡} This pipeline is also managed by AGDC; ASAP would be built only if the larger pipeline proves infeasible. The feasibility of either pipeline depends on a profitable export market for the LNG.\textsuperscript{§} The decline in crude oil prices has resulted in LNG spot-prices falling nearly 50% in the past year to about $7.00/MMBtu (million British thermal units).\textsuperscript{**} The low price also reflects reduced demand for LNG in Asia (70% of the world LNG

\textsuperscript{1} 1993 was the last year a rig capable of drilling offshore was based in Cook Inlet.
\textsuperscript{†} Subsequently in 2015, the state agreed to buy TransCanada’s share.
\textsuperscript{‡} Cost is estimated $45-$65 billion.
\textsuperscript{§} Either pipeline would provide gas directly to Fairbanks.
\textsuperscript{**} 1,000 cubic feet (1 Mcf) = 1,027,000 Btu (1 MMBtu).
market) due to fuel-switching from gas to oil and restart of nuclear plants in Japan and Korea; also contributing to the decline in LNG price is supply from new LNG plants, mainly from Australia.

Due to low price and reduced demand, some LNG plants slated for construction in Australia, Africa, and Canada have been postponed or cancelled. With low oil prices predicted for several more years, the odds are significantly against construction of a pipeline from the North Slope to the Kenai Peninsula for the foreseeable future.

Given the uncertain future of a North Slope pipeline, the state is proceeding with an alternative means to supply Fairbanks with natural gas and proceeding with the Susitna River hydropower project.

**Fairbanks LNG**

Energy prices in Fairbanks are the highest in the Railbelt. Fuel oil, propane, wood, coal, and gas are used for space and water heating. Only 100 buildings are connected to Fairbanks Natural Gas LLC (FNG) natural-gas distribution system. FNG has a small LNG facility located on the north side of Cook Inlet; from there, the LNG is trucked to Fairbanks where it is regasified and distributed. Golden Valley Electric Association (GVEA) relies on oil, naphtha, and coal for its power generation, as well as purchasing electricity from Southcentral utilities.

According to the Fairbanks North Star Borough, converting all the city’s electric power generation and heating to natural gas would require about 20.5 Bcf/year. Achieving this conversion depends on a reliable supply of natural gas from the North Slope pipeline to a yet-to-be constructed distribution system within the borough and city. In 2012, the borough established the Interior Alaska Natural Gas Distribution Utility (IGU) for the purpose of building a natural-gas distribution system to pipe gas from the “city-gate” to homes and businesses in the town.

With the ongoing uncertainty about the feasibility of a North Slope gas pipeline, the 2012 legislature authorized Alaska Industrial Development and Export Authority (AIDEA) to finance a small LNG plant on the North Slope capable of producing 9 Bcf per year to be trucked to Fairbanks; stipulating the natural gas must cost consumers no more than $15.00/Mcf at the “burner-tip;” currently, FNG customers pay about $23.00/Mcf. In 2014, AIDEA’s Interior Energy Project requested proposals to deliver LNG from the North Slope to Fairbanks, but none of the proposals were able to do so at the required price; instead, proposed prices ranged from $18.00 to $20.50/Mcf. As a consequence, the

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2 City-gate” refers to the point at which natural gas is delivered to the utility at the wholesale price.
3 “Burner-tip” refers to the end-use of the natural gas, e.g., a residential water-heater.
2015 legislature removed the requirement AIDEA source gas from the North Slope, but still stipulated the $15.00/Mcf price at the burner-tip. AIDEA then solicited a second round of proposals; selecting two finalists—one proposing to deliver LNG from Cook Inlet, the other from the North Slope—with a decision expected in February 2016.

**Susitna River Hydropower**

In 2010, the legislature passed HB 306 stating, “it is the intent of the legislature that the state receive 50% of its electric generation from renewable and alternative energy sources by 2025.”

At the direction of the legislature, Alaska Energy Authority (AEA), a division of AIDEA, evaluated renewable energy projects and recommended damming the Susitna River. The legislature agreed and appropriated funding for AEA to develop an application to the Federal Energy Regulatory Commission (FERC) to obtain a license to construct and operate the so-called “Susitna-Watana” hydropower project. Estimated project cost of construction is $5.7 billion (2014$), not including financing or the $1 billion upgrade to the Railbelt grid necessary for the economic dispatch of Susitna power. (The cost estimate is predicated on a 5-year construction period commencing in 2019.

The “centerpiece” of the project would be the 735-foot-high Susitna dam, 184 miles upstream of the river’s mouth on Cook Inlet. This would be the largest dam to be built in the United States since the Bureau of Reclamation completed Glen Canyon Dam above the Grand Canyon in the 1960s. The dam would impound the upper Susitna River within a 24,000 acre, 42-mile-long by 1-mile-wide reservoir. The reservoir would discharge through three 200-MW turbines, generating about 2,800 gigawatt hours annually—slightly more than 50% of current Railbelt electric energy use—thereby displacing about 19 Bcf of natural gas that would otherwise be necessary for electric-power generation.

**EFFICACY OF STATE INITIATIVES**

The likelihood of the state-sponsored energy-supply initiatives achieving the desired goal of energy security and affordability for the Railbelt is examined below. Of the state’s initiatives described above, only the Cook Inlet gas initiative has been fully implemented.

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*This is the median estimate based on a minimum cost of $4.46 billion and a maximum cost of $6.80 billion (AEA 2014).

† “Economic dispatch” is the ability to use the most economic generation to meet demand throughout the grid. The transmission infrastructure at present prevents economic dispatch.

‡ Construction likely will not begin until 2024.
Cook Inlet Tax-Regime

Will It Solve the Supply Problem?

Since 2012, Hilcorp has been the Inlet’s largest natural gas producer. Hilcorp states it is “committed to a long-term capital investment plan that aims at slowing decline and increasing production from Cook Inlet’s existing, aging fields.” As a result of Hilcorp reworking many existing wells and drilling 29 new wells in the legacy gas fields, there is sufficient natural-gas to meet Railbelt demand through 2018.

Hilcorp and other independents have stated the favorable tax and royalty climate has been a significant factor influencing their investment decisions. However, without a full accounting of Hilcorp’s business operations, including the tax credits it has obtained, a definitive assessment about the effect of the tax-regime on investment by Hilcorp is not possible. Nonetheless, the available information about drilling costs and tax credits, limited as it is, would suggest the credits have not been crucial to Hilcorp’s and other independents investment in the legacy gas fields.

Overall, Cook Inlet oil and gas companies have received about $1.8 billion (nominal$) in tax relief for their oil and gas investments, including nearly $1 billion in refundable credits, with most of this benefit having accrued to industry since 2006. Using different tax credits has allowed oil and gas companies to be reimbursed as much as 65% of their Cook Inlet exploration and development expenses. From 2006 through 2015, the industry invested about $940 million drilling wells to add to gas reserves in the legacy fields (see Appendix A). Hence, about $500 million (nominal$) in credits would not be an unreasonable estimate.

Wells drilled in existing gas fields from 2006 through 2015 added about 480 Bcf to reserves (see Appendix B). Therefore, when tax credits are taken into account, the companies’ cost of producing gas from wells drilled from 2006-2015 averaged about $1.00/Mcf (nominal$). From 2006 through 2015, gas sold for an average price of about $6.60/Mcf at the city gate. With transportation and

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1 The State of Alaska does not disaggregate revenues from oil production from revenues received from natural gas production; nor does it disaggregate tax credits claimed for oil exploration, development, and production from those claimed for gas exploration, development, and production; nor does it report revenue received solely from the Cook Inlet oil and gas or report credits claimed specifically from the Cook Inlet oil and gas province. (Dan Stickel, Department of Revenue, Personal Communication, June 22, 2011.)

† 2006 through June 2015: $0.1 billion credits against tax liability; $0.8 billion Cook Inlet tax reductions (through 2013) due to the tax cap still tied to “Economic Limit Factor”; and $0.9 billion refunded credits (most of these since 2013).

‡ $940 million does not include cost of wells drilled offshore by Furie and Buccaneer.

§ Based on the prices paid by Enstar from 2006-2014 (see Appendix C).
storage tariffs about $0.99/Mcf and operating expenses about $0.01/Mcf, the companies net about $4.60/Mcf before taxes. Producers’ net revenue before taxes from the sale of 480 Bcf of gas will be about $2.2 billion (nominal$), which is a 14-month payback on investment and a 30% rate-of-return with tax credits, and 26% rate-of return without tax credits (see Appendix B).

Given the rate-of-return, the major result of state tax incentives has been to make profitable investments in existing gas fields even more profitable. In other words, it would appear the investment would have occurred without the tax credits. Even if it were the case tax credits have been crucial to adding reserves to the existing gas fields, the additional reserves have merely extended the date when supply will fall short of demand.

If all the economically recoverable reserves are produced by continued investment in new wells, gas supply from the existing fields will still fall short of demand around 2030 and then decline 8% a year until the fields are totally depleted, sometime in the 2040s. Only finding and developing new gas fields will provide a long-term supply of gas to the Railbelt from Cook Inlet. According to geologists, these gas fields are most likely to be found offshore in upper Cook Inlet. Drilling offshore in Cook Inlet requires a so-called “jack-up rig”.

In 2011 and 2012, respectively, Escopeta Oil (now Furie Operating Alaska, LLC) and Buccaneer Oil brought jack-up rigs to Cook Inlet. Both companies have stated the tax credits were crucial in their decision to drill offshore. Despite the public perception that these companies were embarking on natural-gas exploration, both companies were actually targeting oil. Furie drilled the Kitchen Lights Unit, where oil and gas had already been found, but development was judged to be uneconomic; not surprisingly, Furie found oil and gas. Likewise, Buccaneer found oil and gas in the Cosmopolitan Unit where oil had been previously discovered. In 2014, on the verge of bankruptcy, Buccaneer sold its interest in Cosmopolitan to BlueCrest Energy.

Furie estimates the Kitchen Lights field holds a total of 750 Bcf. In 2015, Furie installed a gas-production platform; Furie’s total investment in Kitchen Lights gas production is $280 million. With $20 million per year in debt service, Furie must sell 85 MMcfd (31 Bcf annually) for Kitchen Lights gas production to be

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* Operating expenses in Cook Inlet are considered proprietary, but are estimated to be about $0.01/Mcf; transportation (i.e. pipeline tariff) and storage costs are costs paid by the utility, not the producers.

† The jack-up rig credit is specifically in lieu of the 30% or 40% exploration credits or any credits for capital costs or net operating loss. Thus far, the jack-up rig credit has not been claimed. Using other credits, Furie and Buccaneer could receive up to 65% reimbursement, with fewer requirements for information submission to the state and without the need to pay back the credit once production begins. Consequently, the companies have determined that it is more advantageous for them not to use the rig credit. (Dan Stickel, Department of Revenue, Personal Communication, November 27, 2015)
Thus far, however, Furie has contracted only with Homer Electric Association (HEA) to supply 4 to 6 Bcf per year (about 10 MMcfd) starting in 2016. Furie does not anticipate additional gas contracts until at least 2019, when Hilcorp’s current utility contracts will have expired; nor is it likely Furie will find buyers in the export market. Because Furie’s cash flow from sales to HEA will only be sufficient to pay the interest on its $200 million loan, the company plans to operate at a deficit for the next few years.

Anticipating little demand for its gas, BlueCrest initially decided to develop only oil and not gas from Cosmopolitan. In November 2015, however, BlueCrest reached an agreement with WesPac Midstream LLC, a liquefied-natural-gas company, which has WesPac funding gas development and production; production is slated for sometime in 2018. BlueCrest estimates the Cosmopolitan field could produce 70 MMcfd, about 22 Bcf annually.

After 2020, when drilling new wells in existing Cook Inlet gas fields will no longer be economic, the shortfall will create demand for gas from Furie and BlueCrest. Based on the expected decline in gas from existing gas fields, the additional reserves from Kitchen Lights and Cosmopolitan fields would meet Railbelt utility demand through 2035—assuming Furie’s and BlueCrest’s estimates of reserves are accurate and the gas is not exported. Still, given the problematic profitability of the export market, compounded by the uncertainty surrounding a North Slope pipeline, the independents are not likely to invest in exploring for new gas fields in offshore Cook Inlet.

Even though the DNR leadership believes the tax-regime has catalyzed a Cook Inlet “renaissance”—a term suggesting the independents are busy finding new gas fields in their quest for oil, thereby replicating the accomplishment of the major oil companies 50 years ago—their staff is more cautious as they observe that "new off-shore platforms and pipelines to onshore facilities require significant investment, and the offshore development leads evaluated in this study appear to be un-economic if the sole source of revenue is gas production" (emphasis added). The fact is the industry does not consider development of the gas resource to be profitable.

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* The Railbelt uses 190 MMcfd on average. If all power-generation and space heating in Fairbanks were to convert to natural gas, Railbelt demand would increase about 47 MMcfd.
† Furie is now only able to sell in the LNG spot market, but given the current price of about $7.00/Mcf and a forecast of even lower prices for the next few years, profitability of exporting is problematic.
‡ Not only is profitability of exporting questionable, but also ConocoPhillips is limited to the volume of LNG it is permitted to export: ConocoPhillips is requesting an extension of its federal LNG export license. The extension would allow the company to export up to 40 Bcf over a two-year period starting in 2016. If the export market becomes more profitable, and these other companies are able to ship more gas to foreign buyers, then the supply available to Railbelt utilities is more rapidly depleted. Further, even if the export market were to become more profitable, spot-market price volatility is likely to discourage investment in Cook Inlet gas exploration and development.
Unfortunately, incentivizing investment in oil exploration has not resulted in finding new gas as the legislature anticipated. The Cook Inlet tax and royalty regime has failed to mitigate the market conditions that continue to preclude significant investment in the Cook Inlet gas resource. Essentially the Cook Inlet tax-regime has mainly served to increase the profitability of oil and gas development in existing fields; this development would have been profitable without the credits (see Appendix B). In fact, the CEO of Buccaneer Oil, an Australian company, exclaimed "it's about the closest thing you're going to get to free money from a government in the world."*  

**Will It Solve the Affordability Problem?**

The cost of reworking wells and drilling new wells to extract the remaining reserves caused the average wholesale price of Cook Inlet natural gas to more than triple from less than $2.00/Mcf to about $6.50/Mcf during the past 15 years.† In 2015, Hilcorp extended the Chugach Electric contract through 2023, reducing the price from $7.72/Mcf in 2017 to $7.35/Mcf in 2018; to be followed by a 2% increase per year.‡  

The state is forecasting natural gas prices to double in real terms by 2040.§  Therefore, unless the median household income also doubles in real terms by 2040, gas will have become less affordable.

**North Slope Gas Pipeline**

**Will It Solve the Supply Problem?**

With North Slope gas reserves estimated to be 200 trillion cubic feet (Tcf), a pipeline would guarantee a long-term, energy supply for the Railbelt. However, a decision to invest up to $65 billion in the Alaska LNG project is not likely for a few years at least, given the low LNG price, and further, will be contingent on each partner’s assessment regarding the fit of the Alaska project with the company’s priorities and portfolio of investments worldwide.

Should the Alaska LNG project be abandoned, the state is supposedly committed to its back-up plan of the smaller-volume Alaska-Stand-Alone-Pipeline.

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* When the legislature decided to fund ASAP, it had already concluded investment in finding and developing the Cook Inlet gas resource is unlikely.
† Ironically, not long after this pronouncement, Buccaneer Oil declared bankruptcy.
‡ $6.47/Mcf is the average price paid by Enstar in 2015, average price for other utilities varies; Enstar paid $1.32/Mcf in 1999.
§ Hilcorp Consent Decree caps the wholesale price at $7.72/Mcf through 2017. (Furie has not disclosed its wholesale gas price.)
§§ $10.05/Mcf in 2029; $12.85/Mcf in 2039; $14.25/Mcf in 2049; and $14.35/Mcf in 2059 (all prices in 2014$).
However, this pipeline, too, depends on securing long-term contracts at adequate prices to ensure sufficient revenues.\textsuperscript{53}

**Will It Solve the Affordability Problem?**

Other than the overall cost estimate of up to $65 billion, there is no publicly available information about Alaska LNG costs. Considerably more information is available about the economics of ASAP. AGDC estimates that project would cost $9.93 billion (2014\$).\textsuperscript{54} The cost of financing would be at least $4.8 billion (2014\$), assuming a 5\% interest rate.\textsuperscript{55} The estimated cost of operating and maintenance over 30 years is $147 million (2013\$).\textsuperscript{56} As pipeline throughput is the main variable affecting the tariff for moving the gas; ASAP must operate at or near 100\% capacity (500 MMcfd) to be financially viable.

Based on the costs above, the pipeline tariff would be $5.50 – $6.75/Mcf (2011\$) to the Fairbanks city-gate, and $8 to $9.75/Mcf to the existing Southcentral pipeline north of Anchorage.\textsuperscript{57} ADGC estimates the North Slope gas producers would price the gas at $2.00/Mcf (2011\$) at the wellhead and estimates “drying” (conditioning) the gas before it enters the pipeline would cost $2.00/Mcf.\textsuperscript{58} Price of gas at the burner-tip would be $11.50 – $14.00/Mcf (2011\$) for Fairbanks, and $11.50 – $14.50/Mcf for Anchorage. Given economy-of-scale, the LNG pipeline tariff is likely to be less than the ASAP tariff, assuming throughput is near 100\% as well.

Either pipeline should deliver gas to the Railbelt at a price competitive with imported LNG.\textsuperscript{59} Nonetheless, the price of gas at the burner-tip in Southcentral would be twice the current Cook Inlet gas price, which makes gas less affordable in real terms than it is at present. Further, although the necessary long-term contracts (i.e. 20-year or more contracts) would have been negotiated prior to building a pipeline, there is the risk of an undersubscribed pipeline once the charter contracts expire. In that case, the pipeline tariff could increase substantially.\textsuperscript{‡}

**Fairbanks LNG**

**Will It Solve the Supply Problem?**

Either Cook Inlet LNG or North Slope LNG delivered to Fairbanks should provide sufficient supply until the main supply of gas for the Railbelt is secured. The Fairbanks LNG initiative is not intended as a permanent solution to the northern Railbelt energy-supply problem.

\textsuperscript{1} Uncertainty range of ±20\%.

\textsuperscript{†} Similar to how Susitna hydropower might be financed.

\textsuperscript{‡} For example, if there were no export sales and ASAP provided gas only to the Railbelt (40\% throughput), the tariff would be $15.00/Mcf.
Will It Solve the Affordability Problem?

A sufficient supply of natural gas to the Fairbanks area would make energy there more affordable. AIDEA intends to control the price of gas at the burner-tip to $15.00/Mcf (2014$), which would be more affordable than fuel oil, which is the primary residential heating fuel within the IUG service area. Moreover, in June 2015, AIDEA purchased Pentex Alaska Natural Gas Co. LLC, parent company of FNG, for $52.5 million. The sale includes the LNG plant at Port MacKenzie on Cook Inlet, as well as the trucks to transport LNG to Fairbanks.\textsuperscript{60}

AIDEA plans to transfer ownership of Pentex assets to the Interior Gas Utility, which incorporates the FNG service area within its borough-wide service area to establish a single gas utility. AIDEA claims combining the utilities should save roughly $2 million per year in operating costs, along with reducing the cost of storage and distribution from $5 to $11 million, compared to having two utilities. Also, FNG’s current customers would see their rates fall 13% because a public utility does not have the tax liabilities of a private utility, such as FNG.

Susitna Hydropower

Will It Solve the Supply Problem?

If a North Slope pipeline is not feasible or a long-term supply of Cook Inlet gas is not developed, then the state is likely to build the dam; assuming FERC issues a license for the project.

Since Susitna power would replace 19 Bcf of Cook Inlet gas annually, damming the Susitna River does not solve the Railbelt energy supply problem, because the Railbelt would still require at least 51 Bcf annually of natural gas for power generation and heating.

Will It Solve the Affordability Problem?

Susitna power would displace more than 50% of Railbelt generation. The dam would generate the same amount of electricity annually as 19 Bcf of natural gas does now. AEA assumes the dam will operate for at least 100 years; thus, the project would have the effect of reducing natural gas use by 1,900 Bcf during that time. In other words, during its first 100 years of operation, the hydroelectric generation is equivalent to burning about 1,900 Bcf of natural gas for electric-power generation.\textsuperscript{\textdagger}

Given AEA’s estimate of $11.5 billion (2014$)\textsuperscript{\dagger} to construct the project and to

\textsuperscript{\textdagger} This assumes the efficiency of the thermal power generation remains constant over 100 years.

\textsuperscript{\dagger} $5.7 billion in capital cost; $2.8 billion in financing (5% interest over 50 years); $3 billion for operation and maintenance (over 100 years); all costs in 2014$.
operate and maintain it for 100 years,\(^*\) \(^61\) 100 years of hydropower from the Susitna River is equivalent to the state obtaining a long-term contract to purchase 19 Bcf of natural gas annually for 100 years at a constant price of $6.00/Mcf (2014$), which would be at less than 50% of the average price of gas (in 2014$) over the same period.\(^\dagger\)

According to AEA, Susitna power generation would save about $220 million (2014$) per year on Railbelt variable-production costs. Variable-production costs are fuel and operations/maintenance, but the production-cost savings are mainly due to reduced natural gas purchases for thermal generation.\(^\ddagger\) \(^62\) Without access to an hourly dispatch model of the Railbelt electric system, but nevertheless relying on AEA's assumptions about hydropower generation and natural gas prices, a "back-of-the-envelope" calculation of production-cost savings estimates savings would instead be $135 million (2014$) per year (levelized) during the first 50 years of operation (as explained in Appendix C).

However, during the first 10 years (2029-2038), Susitna power will cost about $77 million more per year than the fuel it displaces. Ratepayers will, therefore, pay higher electric bills than would be the case without the dam during that period. Beginning in 2039, Susitna power will cost less than the displaced fuel; so that, by 2044, the savings from avoided natural gas purchases will equal the "extra" $777 million paid for Susitna power from 2029 through 2038.

Consequently, starting in 2045, monthly electric bills will be less with the dam than would have been the case without the dam.

Nonetheless, even though the Railbelt residential and business electric bills after 2044 will be less, the monthly electric bill will still continue to increase due to the fact 50% of the electricity is generated from natural gas. Further, the hydropower project will have no effect on heating costs, since most heating is by natural gas. Therefore, because 75% of the monthly residential and business energy bills (electric and heat) is due to natural gas, Susitna power will not stabilize the price of energy over time, albeit hydropower will make the total energy bill for power and heat more affordable than it would be without the dam.

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\(^*\) Analysts have pointed out the problematic nature of AEA’s cost estimates, but for this evaluation of Susitna hydropower affordability/pricing, AEA projections are used.


Gregg Erickson, “Dreams, Risks and Realities: An Economic Analysis of Plans to Dam Alaska’s Susitna River,” Gregg Erickson and Associates, 2014;

Mark Foster, “Susitna Hydroelectric Opportunities & Risks,” Mayor’s Energy Task Force, April 7, 2011.

\(^\dagger\) AEA forecasts the gas price (in 2014$) to double by 2050.

\(^\ddagger\) AEA calculates Railbelt production-cost savings using the economic-dispatch model PROMOD. The runs of the model have not been published. Apart from its production-cost savings estimate, AEA also estimates additional savings from 1) transmission improvements; 2) retirement of thermal power plants; and 3) increased cost of natural gas due to a carbon tax.
A STATE-OWNED GAS SUPPLY

Alaska’s energy policy is predicated, in part, on the supposition the state should share responsibility with the utilities for ensuring communities have an adequate energy supply at an affordable price. Yet, none of the state’s proposed solutions for the Railbelt would solve both problems of supply and affordability: the pipeline initiative would solve the supply but not the affordability problem; Cook Inlet tax and royalty incentives may have extended the life of the existing fields, but the increase in reserves obtained by drilling new wells has escalated the wholesale price of gas about 300%, without ensuring a long-term supply of natural gas; and Susitna hydropower would provide lower and stably priced electricity—if AEA’s assumptions about project cost and forecast of natural gas price are accurate—but would provide only 25% of Railbelt energy supply at current demand.

The key to affordable hydroelectricity—state ownership and control of supply and price—is the key as well to the only alternative that might actually secure a long-term, affordable, stably priced energy supply: the state producing natural gas from its own Cook Inlet resource; just as it would produce electricity from its own Susitna River resource; with the gas priced at the cost of production; just as electricity from the dam would be priced at the cost of production.

Rationale for State-Produced Natural Gas

Historically, state ownership and operation of hydroelectric projects have been accepted practice. The state, however, chooses not to develop its own oil and gas resources; instead it chooses to entrust industry with ownership and production, while taking its share of the resource value in lease payments, taxes, and royalties. Yet, when private enterprise is unwilling or unable to make the investment necessary to develop oil and gas resources, the state has been willing to share the risk and, in some instances, assume all the risk.

The state shares the risk of 1) Cook Inlet oil and gas development by having relinquished about $1.8 billion in tax and royalty payments; 2) bringing gas to Fairbanks with its $333 million Interior Energy Project, and 3) bringing North Slope gas to the Railbelt with the Alaska LNG pipeline, appropriating $180 million thus far to assess its feasibility. The state is assuming the entire risk of 1) the Susitna River hydropower project, spending $192 million thus far on studies for a license application, and 2) the Alaska-Stand-Alone Pipeline, having spent

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1 The state has financed and operated several hydropower projects and has subsidized rural energy cost through the Power Cost Equalization Program; however, the state’s responsibility for Railbelt energy supply is a political choice, not a legal obligation; the legal obligation resides with the utilities.

2 Even though Susitna hydropower produces electricity and not gas, it helps with the gas supply situation by substituting energy from water for energy from gas.
about $300 million on pre-construction studies and engineering.* 66

All told, the state has subsidized the Cook Inlet oil and gas industry $1.8 billion in tax relief and allocated $1.0 billion more to other Railbelt energy-supply initiatives.†

Unfortunately, none of these state-sponsored initiatives have yet ensured a long-term, energy supply for the Railbelt. Since the legislature has determined “citizens have a need for natural gas that will not be met by the private sector and that it is unacceptable for those citizens to be without natural gas (emphasis added),”‡ 67 the obvious option overlooked so far would be the state producing its own natural gas. At least two investment decisions by the state support this approach: AIDEA’s decision to become a partner with Buccaneer by investing $23.4 million in the jack-up rig,§ and AIDEA’s agreeing to partner with Furie in the Kitchen Lights gas-production platform with a $50 million investment.** 68

State-produced gas from offshore Cook Inlet would ensure a long-term supply of natural gas at an affordable price with less investment than any of the other options.††

There is limited information about the cost of finding and developing a new gas field in offshore Cook Inlet. Furie claims it has invested $280 million (2014$) investment to develop the Kitchen Lights field, with 750 Bcf of reserves (this estimate has not been independently verified).‡‡ 69 Therefore, Furie’s cost to produce the gas at the well head is $0.38/Mcf; however, assuming Furie receives tax credits of at least 50% of its investment, its subsidized cost of production is $0.19/Mcf. The cost of financing and operations and maintenance will add

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* According to AEA, $300 million more will be necessary to complete Susitna licensing, and post-licensing geotechnical work, engineering and permitting; the state has not announced how much more funding will be necessary for Alaska LNG studies and engineering.
† Legislative authorizations and appropriations include agency appropriations, grants, and loans.
‡ The state’s self-imposed obligation to ensure energy security acknowledges, at least tacitly, that when the private sector cannot produce the necessary goods and services (i.e. “market failure”), the state has a responsibility to do so.
§ Buccaneer drilled in the Cosmopolitan Unit where oil and gas had already been discovered. Geologists have concluded the major, yet-to-be discovered gas fields are likely not associated with oil, so drilling for oil offshore in other unexplored areas is not likely to find gas with oil.
** AIDEA board of directors agreed to the proposal to invest $50 million, contingent on AIDEA’s confirming the size of the field and the daily production, as well as verification of engineering and construction work, business plan, and other financing. AIDEA had completed a preliminary due-diligence analysis when Furie and AIDEA decided the proposed relationship would not be feasible due to conflicting schedules. AIDEA continues to discuss potential financing options with Furie. (Karsten Rodvick, AEA, Personal Communication, September 11, 2015)
†† There would also be less impact on the state’s ability and capacity to finance other necessary capital projects.
‡‡ Furie has provided conflicting information about its total investment to bring Kitchen Lights into production: 1) $500 million (reported in Alaska Dispatch News, September 21, 2015); 2) $350 million (Furie’s letter to legislators Giessel, Hawker, July 13, 2015); and 3) $280 million (AIDEA).
$0.19/Mcf, for a total (subsidized) cost of production of $0.38/Mcf.* 70 (This cost of production is based on the currently completed wells to access the Kitchen Lights gas. If additional wells are required to access the reserves, the cost to produce gas will increase.)

Even if the cost of finding and producing other offshore gas fields in upper Cook Inlet with equivalent reserves were 300% greater than Furie’s cost—$775 million—the state’s cost of production would be about $1.15/Mcf (2014$).† The state’s investment would provide 4 times the amount of energy at one-fifth the cost of energy from the Susitna dam.‡ If the state were to borrow the $775 million at 5% interest, the cost of production would be $1.60/Mcf, less than one-third the cost of Susitna hydroelectricity. Given the state has paid $1.00/Mcf in subsidies to increase reserves in the legacy fields ($500 million tax-credits to develop an additional 480 Bcf of reserves) and is planning on spending at least $8.00/Mcf to bring North Slope gas to the Railbelt,§ the financial logic for the state producing its own gas seems obvious.**

Moreover, if the State of Alaska were to produce the a natural-gas supply for the Railbelt, the state would be able to invest incrementally and flexibly in gas-field development, which would minimize capital outlay as well as accommodate future investment in those cost-effective, more environmentally benign, renewables, such as wind and geothermal.†† This investment strategy would keep the cost of gas as stable as possible in the long-term; meaning monthly Railbelt energy bills would be relatively stable for the next 100 years.

**Economic Impact of State-Produced Gas**

When finding and developing the Cook Inlet gas resource, the State of Alaska would do what independent oil and gas companies do, which is to hire

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* Furie estimates debt service to cost $20 million annually—assuming investment pay back in 5 years, total financing cost would be $100 million; operations and maintenance about $2 million per year for the 20-years (estimated life of the field), total cost over life of the field is $420 million, plus whatever number of additional wells are required to access reserves.
† U.S. Department of Energy estimated $1 billion (2004$) to find and develop about 1,300 Bcf—$0.75/Mcf. (Charles P Thomas et al., “South Central Natural Gas Study,” Strategic Center for Oil and Natural Gas, June 2004, 2004, p. xxi.).
‡ Assuming Susitna energy cost is about $6.00/Mcf.
§ North Slope gas reserves are stranded because there is no way to get the gas to market. So, by building and operating a pipeline to get the gas to market, the state can be said to be producing the gas. Hence, the cost of producing North Slope gas would be the pipeline construction and financing cost, which works out to about $8.00/Mcf. The cost of the gas itself, which is the price the gas owners would receive for the gas at the wellhead, is not counted in the state’s cost of production; the gas price is to be determined by the gas owners—AGDC assumes the owners would price the gas at least at $2.00/Mcf (2011$).
** All costs in 2014$.
†† Sufficient investment in seismic surveys and exploratory drilling would be necessary initially to locate enough gas to allow for incremental development and production.
contractors for seismic work, exploratory drilling, and construction of production platforms. Similarly, the state would hire private firms to construct the dam and the pipeline. Compared to the dam or pipeline, however, the direct, short-term benefit of jobs and local purchases from construction of offshore, gas-production platforms would be less.

AEA’s estimate of short-term benefits during the dam’s 10-year construction period is $2.6 billion in construction contracts; $1.8 billion in indirect and induced economic output (from the direct project spending); and $630 million in labor income, for a total of $5 billion. While expenditures from building a dam or pipeline would be significantly greater than expenditures by the state when developing natural gas fields offshore in Cook Inlet, the benefits from construction of a dam or pipeline are accompanied by significant social and environmental costs. These costs/impacts would affect many people and businesses who receive no direct benefit from construction expenditures.

Once the dam is constructed and generating power, AEA estimates long-term benefits of hydroelectric generation are $11.2 billion in production-cost savings; $345 million from retirement of power plants; $1.1 billion in avoided power outages; and $1.7 billion in avoided carbon taxes/fees (all, 2014$).

However, the cost savings from retiring some power plant and avoided power outages AEA would attribute to hydropower generation seem quite problematic, because the improvement to the transmission system is expected to reduce power outages due to increased capacity and reliability and because replacement of old generation by new more efficient power plants will occur even if the dam were not constructed. Moreover, cost savings from an avoided carbon tax/fee is also problematic; to be counted only if the federal government were to enact this tax/fee and only if Alaska utilities were not exempt from the tax/fee. Therefore, the most significant (and relatively assured) cost savings from Susitna hydropower would be the variable-production costs, given AEA’s assumption about future natural gas pricing.

Assuming the hydropower project’s first full year of operation is 2029, it would displace about 19 Bcf of natural gas that year. In 2029, AEA predicts the

\* AEA’s cost/benefit analysis does not account for social and environmental costs associated with construction and operations (environmental-mitigation expenditures are counted as benefits).
\† As explained in Appendix C, AEA over-estimates the production-cost savings: rather than $11.2 billion over 50 years, the savings would be $6.5 billion (2014$).
\‡ Operation and maintenance of the hydropower project and operation and maintenance of gas production facilities entail jobs and expenditures for goods and services.
\§ Susitna hydropower would obviate the need for building new plants when old plants need to be replaced, but arguably this would not count as a cost-savings because the capital cost of the hydropower facility is greater than the capital cost of thermal generation per installed MW.
\** In the event a carbon tax/fee were to be enacted, Alaska might be exempt from the tax/fee by virtue of its lack of access to GHG emission-free power from a large regional grid, as would be most utilities in the contiguous 48 states.
wholesale price of natural gas will be $10.05/Mcf (2014$), but as explained in a preceding section, Susitna power would cost utilities about $77 million per year more from 2029 through 2038 than would have been paid for gas-fired generation. If instead state-produced gas were available in 2029, the cost-savings would be $150 million, assuming $1.15/Mcf (2014$) or $142 million, assuming $1.60/Mcf. From 2029 through 2038, cost savings from state-produced gas (priced at $1.15/Mcf) would total about $1.7 billion, or about $1.68 billion (priced at $1.60/Mcf), while production-cost savings from hydropower would be a minus $770 million.

When the legacy Cook Inlet gas fields are no longer producing, sometime around 2040, the cost savings from state-produced, natural gas would be about $745 million (2014$) per year: 12 times the production-cost savings realized from purchase of Susitna power. Over 50 years (2029–2079), the production-cost saving due to purchase of state-produced gas would be about $35 billion (2014$), which otherwise have been revenue earned by gas producers. This amount is $24 billion more in savings that AEA predicts will be saved from the hydropower project. Presumably, the preponderance of this savings would remain and circulate in Alaska, albeit some portion of the savings would be spent or invested out of state.

Hence, state-produced gas would spur greater economic development in the regional economy than any of the current state-sponsored, energy-supply initiatives, because energy costs will be proportionally less of total expenditures by local business and households; social and environmental costs would be significantly less; and because the cost-savings would be more equitably distributed among all residential and business customers than the benefits from dam or pipeline construction expenditures. The beneficial effect of state-produced gas on Railbelt economic development would be far greater than if the gas were to be supplied by private industry, in which case most of the $35 billion that would have circulated throughout the Railbelt economy from 2029 to 2080 would instead have been received and retained by the gas producers.

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* See Appendix C.
† Just as hydroelectricity would be priced at the cost of production, so would state-produced gas. The wholesale price of gas at the city-gate includes $1.00/Mcf for transportation and storage between the well head and city-gate.
‡ This calculation assumes legacy gas fields will no longer be producing sometime around 2040.
§ This assumes state-produced gas will meet demand of at least 70 Bcf annually.
** This paper estimates the total production-cost savings from the hydropower project to be $6.7 billion (see Appendix C); therefore, cost savings from state-produced gas would be about $28 billion greater than cost savings from Susitna hydropower.
†† According to AEA, 214,227 residential, 29,832 commercial, and 535 industrial customers are served by Railbelt utilities.
‡‡ About 30% of the total savings would accrue to residential ratepayers, with commercial and industrial customers receiving 70%. (see Railbelt Integrated Resource Plan, Table 3-2, p.3-5.)
If the State of Alaska produces the gas, it would not receive revenue from royalty payments and production taxes, which would amount to about $50 million (2015$). The state could choose to capture this “lost” revenue through a surcharge on its gas sales, albeit the fact of lost revenue from royalty and production tax presumes that private companies would have invested in finding and developing resource. Given the state has already relinquished more than $1.8 billion in revenue from Cook Inlet oil and gas without securing a long-term gas-supply, potential loss revenue of $50 million from tax and royalty payments pales in comparison to the benefit to the Railbelt from state-produced gas.

State-produced gas would seemingly provide the maximum benefit from developing its Cook Inlet resource; yet, the state has not considered implementing this option—the only option that could provide long-term energy security and ensure stably and affordable energy prices. The state instead has been unnecessarily subsidizing well drilling in the legacy gas fields, and continues to sell offshore oil and gas leases to lessees who have no intention of exploring for gas because they do not consider finding and developing offshore gas profitable.

Environmental Impact of State-Produced Gas

There are impacts associated with finding and developing gas in offshore Cook Inlet. However, because the gas fields lying offshore are unlikely to be associated with oil, the environmental dangers of oil development in marine waters are absent when developing this gas resource. Nonetheless, seismic surveys and exploratory drilling for gas can affect marine life, particularly whales. Drilling disturbs the seabed and benthic habitat within the drill’s footprint; drilling muds, which are used to lubricate and regulate pressure, can be toxic to marine life if mishandled. When drilling entails hydraulic fracturing, the specially concocted hydraulic fluids are known to be toxic to marine life if fluid

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1 This amount is based on the Department of Revenue’s 2005 revenue forecast, which is the last year the department made a forecast of gas-production revenue from Cook Inlet.

† According to Alaska Oil and Gas Association, citing a 2014 study by McDowell Group, the average annual economic impact on the Kenai Peninsula borough from the oil and gas industry is 6,000 jobs (25% of the all jobs) and $430 million in total wages. If it were left to the private sector to find and develop the Cook Inlet resource and the companies determined doing so is not sufficiently profitable—as they evidently have determined—there would be no benefit to the local economy.

‡ Oil and gas companies gain access to offshore upper Cook Inlet by acquiring leases from the State of Alaska. The lessee is not required to explore for oil and gas, but is only required to make lease payments. Should the lessee find oil or gas, the lessee is required to develop and produce the resource only if it is reasonably profitable to do so; but the lease does not define “reasonable” profit. In practice, if the lessee does not believe a reasonable profit can be obtained from producing gas, the gas will not be developed, remaining “stranded;” and there is little the state can do about that, given the existing regulations.

§ There remains the possibility that, when drilling for gas, oil may be encountered, which would significantly increase the potential of harm to the marine environment.
were to leak into the sea. When drilling, there is also the risk of gas escaping into the atmosphere, where it would contribute to the greenhouse effect.

Construction of production facilities, including pipelines from the platform to shore, poses some environmental hazard. During production, produced water is the largest waste stream generated by the oil and gas industry. Produced water is any water from the well/reservoir brought to the surface, and it is toxic to marine life if it were to enter the sea. However, as the gas to be discovered in Cook Inlet is expected to be dry gas—given the geological formation and rock strata—produced-water volume should be much less than that of gas field development associated with oil reservoirs.

Compared to producing hydroelectricity from damming the Susitna River, the environmental impacts from developing Cook Inlet natural gas offshore would be far less damaging to the local environment. In fact, of all renewable-energy systems, hydropower is likely to cause the most damage to the local environment, mainly because the freshwater ecosystems in which hydropower dams are sited are generally the areas with the greatest biodiversity and productivity.

The Susitna River Basin is virtually pristine—anthropogenic impacts are localized and not significant at the watershed scale. Construction of the Susitna River dam and its associated facilities, including roads and transmission infrastructure, will have significant impacts on surface land. The reservoir alone will inundate more than 20,000 acres of land and over 40 miles of the Susitna River channel, including several miles of tributaries. Regulation of the river would affect 184 miles of watershed and potentially affect estuarine habitat at the river’s mouth on Cook Inlet. The alteration of the hydrologic regime will impact water quality and quantity, and habitat resulting in change to fish, wildlife, and plant species composition and distribution.

Many of the impacts just described are the same impacts to watersheds due to climate change. Consequently, the Susitna River dam would exacerbate the impacts to the local environment due to climate change. The impacts to the watershed from the dam would be far more severe than the effects on the watershed from the greenhouse-gas (GHG) emissions of 19 Bcf the hydropower project would displace (19 Bcf of gas is 0.015% of the 122,000 Bcf used worldwide each year).

Further, while hydroelectric generation is greenhouse-gas-free, the claim that Susitna River dam would eliminate GHG emissions from the 19 Bcf of natural

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* Cook Inlet has already experienced significant discharge of produced-water from existing oil and gas production.
† The state justifies the proposed Susitna project not only on the basis of affordable energy, but also because it produces no greenhouse-gas emissions (GHG); because of its supposed potential to “enhance” fish habitat; and because of enhanced recreational opportunity.
gas the dam will displace requires the displaced gas be permanently sequestered. Even if 19 Bcf of natural gas were sequestered every year, the reduction in GHG emissions would not begin to compensate for impacts of the project up and down the watershed—to claim otherwise is an illogical “destroy-the-local environment-to-save-the-planet” calculus. The state would cause far less environmental harm by producing natural gas than it would by producing hydropower.

**Implementing the State-Produced Gas Option**

If state-produced gas from Cook Inlet is the more sensible Railbelt energy-supply option from an economic and environmental perspective, why has the state not considered it? If the state can build a hydropower plant, purchase a gas utility, and agree to be a partner in a gas-production platform, what prevents it from being a gas producer? AIDEA could even jump start this energy-supply initiative by tendering an offer to purchase Furie and Blue Crest gas fields.†

Both the legislature and administration have so far ignored the feasibility of state-owned gas fields—an option justified by the same assumptions and principles as the current slate of state-sponsored, energy-supply initiatives. Perhaps, the state believes it should not compete with the private sector to provide energy to the Railbelt. If this is the case, then the state would not have built the Bradley Lake dam (1991), nor would AEA now be pursuing the Susitna River hydropower project, which, if constructed, would take about 25% of the current Railbelt energy market from private energy producers. Perhaps then, the state is fearful the oil and gas industry would slash in-state investment, including participation in the Alaska LNG project, if the state were to initiate its own gas-production project. Such concern would not be an unreasonable one for a state that is primarily a resource-colony in which the welfare of its residents is hitched to the welfare of industry, principally the oil and gas industry. If state-produced gas is to be a viable option, the state must put aside its fears and act as the sovereign entity it is and as the constitutional mandate to maximize the benefits from resource development would seem to require.

Further, state-produced gas from Cook Inlet would not conflict with the large-diameter Alaska LNG pipeline. Pursuing one supply option does not preclude the other supply option. The main purpose of the pipeline is to provide new a source of general-fund revenue from sale of up to 3.5 Bcf gas daily, which is about 19 times more than the average daily demand for gas in the Railbelt.‡ Moreover, the price of gas delivered to the Anchorage city-gate by the pipeline would be at least $8.00/Mcf (2015$); considerably more expensive than state-

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† The only way to reduce harm to local environments from climate change due to global warming is to harness zero or near-zero GHG-emission energy sources with power systems that do not significantly harm the ecosystems in which they are sited.

‡ If the state did purchase these gas fields, it could prevent gas from being exported.

† AGDC has not published an estimate of anticipated revenue to the state from the LNG pipeline.
produced gas. Therefore, as long as the pipeline gas can sold in the export market, the state receives the maximum revenue from the pipeline, and the Railbelt receives the maximum benefit from state-produced gas.

**CONCLUSION**

As long as the state remains committed to ensuring energy security and affordability for the Railbelt, it cannot afford to ignore the option of state-produced, natural gas from Cook Inlet. This option is the most cost-effective alternative, requiring the least capital investment, yet producing the greatest long-term economic benefit to the regional economy with the least environmental and social impact.

A North Slope pipeline would solve the Railbelt energy supply problem, if not the affordability problem; but the prospect of such a pipeline has dimmed considerably with the decline of crude oil prices and stiff competition from other LNG projects around the world. Given such circumstances, the Railbelt is not likely to have a secure supply of gas from the North Slope by the time Cook Inlet gas falls short of demand.

In the event none of the state’s energy supply initiatives prove viable, the utilities are prepared to import LNG. Ironically, this would be akin to bringing “coal to Newcastle;” but would not require state financing. Ultimately, the utilities, not the State of Alaska, are obligated to provide energy to their customers.

In the meantime, it is time for the state to acknowledge Susitna River hydropower’s promised benefits of diversifying Railbelt energy sources and stably priced electricity comes at too high a price financially and environmentally. The dam project is a distraction from solving the problem of ensuring a long-term, natural gas supply.

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* There would also be less impact on the state’s ability and capacity to finance other necessary capital projects.
ENDNOTES


2 Ibid., p. iv.

3 Ibid., p. 17.

4 Kurtis Gibson, et al., “Cook Inlet Natural Gas Production Study,” Department of Natural Resources, Oil and Gas Division, June 2011, p. 4.

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


10 Kurtis Gibson, et al., “Cook Inlet Natural Gas Production Study,” Department of Natural Resources, Oil and Gas Division, June 2011, p. 4 (Figure 2).


13 Alaska Superior Court, Third Judicial District, “Consent Decree (Case No. 3AN-12-),” November 5, 2012.


15 Charles P Thomas et al., “South Central Natural Gas Study,” Strategic Center for Oil and Natural Gas, June 2004, pp. 74-75.


19 Senate Oil and Gas Tax Credit Working Group, “Summary Report,” December 1, 2015, p. 11.


29 “Declaring a state energy policy,” Alaska Legislature, SCS CSHB 306(FIN) am S.


http://www.legis.state.ak.us/basis/get_single_minute.asp?house=S&session=28&comm=RES&date=20130121&time=1529

Kurtis Gibson, et al., “Cook Inlet Natural Gas Production Study,” Department of Natural Resources, Oil and Gas Division, June 2011, p. 20.

http://www.eenews.net/stories/1059989454


John Burns, “Now is not the time to abandon the Alaska Stand Alone Pipeline,” Alaska Dispatch News, October 26, 2014.


http://www.petroleumnews.com/pnads/742985809.shtml

Ibid.


Ibid.

http://www.petroleumnews.com/pnads/833986534.shtml


70 See: Charles P Thomas et al., “South Central Natural Gas Study,” Strategic Center for Oil and Natural Gas, June 2004, pp. 127-129.


72 Ibid., p. ES-2.

73 Charles P Thomas et al., “South Central Natural Gas Study,” Strategic Center for Oil and Natural Gas, June 2004, p. 155.


### APPENDIX A – WELL-DRILLING EXPENDITURE

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Number Wells Drilled*</th>
<th>Capital Expenditure†</th>
<th>Added Reserves‡</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001-2009§</td>
<td>128**</td>
<td>$1.3 billion</td>
<td>563 Bcf</td>
</tr>
<tr>
<td>2006-2009</td>
<td>44††</td>
<td>$440 million</td>
<td>194 Bcf</td>
</tr>
<tr>
<td>2009-2012‡‡</td>
<td>16</td>
<td>$160 million</td>
<td>70 Bcf</td>
</tr>
<tr>
<td>2012-2015§§</td>
<td>34</td>
<td>$340 million</td>
<td>150 Bcf</td>
</tr>
</tbody>
</table>

* Wells drilled are completed wells onshore – successful and unsuccessful.
† Petrotechnical Resources 2010 report (p. 17) estimates about $1.2 billion capital cost for 128 wells, about $10 million per well (nominal$).
‡ Petrotechnical Resources 2010 report (p.13) estimates average 4.4 Bcf in added reserves per well drilled. Petrotechnical Resources 2012 Update does not provide an estimated average of added reserves for the 128 wells drilled after November 2009.
§ Petrotechnical Resources 2010 report included wells drilled through October 2010.
** 97 development wells; 31 exploration wells (Petrotechnical Resources, 2010, p. v).
†† 39 development wells, 5 exploration wells (Petrotechnical Resources, 2012, (pp. vii, 14, 15).
‡‡ Petrotechnical Resources 2012 report (p. 7) tabulates wells drilled November 2009 through June 2012.
§§ Hilcorp drilled 28 development wells, 1 exploratory well; Cook Inlet Energy drilled 4 development wells; Aurora drilled 1 development well (source: Alaska Oil and Gas Conservation Commission, Data Miner: “Well List”).

**Capital Expenditure Estimate**

<table>
<thead>
<tr>
<th>94 wells drilled (2006-June 2015)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$940 million (nominal$) – total investment prior to tax relief (see Appendix A)</td>
</tr>
<tr>
<td><em>$500 million (nominal$) – net total drilling investment after tax relief</em></td>
</tr>
</tbody>
</table>

**Revenue Estimate**

| 480 Bcf – added reserves from new wells (see Appendix A). |
| 10.5 Bcf – estimated first-year production |
| [80 successful wells 2006 to 2015; † on average 8 successful wells drilled each year; 3.6 MMcf/d average production per well during first year = 10.5 Bcf gas produced during first year production; ‡ production declines about 15 percent per year over next 6 years; § 68 Bcf – average total annual production over 7 years] |
| $4.60/Mcf – average net revenue per 1,000 cubic feet produced (before taxes) |
| [$1.00/Mcf (nominal$) – cost of producing gas from wells drilled from 2006-2015; $1,00/Mcf – average cost transportation, storage; $4.60/Mcf net to the producers; $6.60/Mcf – average price per Mcf at city-gate ‡] |
| $48.4 million – first year net revenue from first 8 wells |
| [10.5 Bcf X $4.60/Mcf = $48.4 million; second year net revenue = $89.5 million ($41.1 million = 2nd year revenue from first 8 wells + $48.4 million from first year of next 8 wells)] |
| *$2.2 billion (nominal$) – total net revenue (before taxes)* |

* Estimated 50 percent tax benefit on total capital investment is a conservative estimate (Alaska Department of Revenue, "Oil and Gas Tax Credits- Cook Inlet Focus Presentation to Senate Tax Credit Working Group," September 8, 2015, p. 11). |
† 2001-2009 – 105 successful wells/128 completed wells (Petrotechnical Resources of Alaska, "Cook Inlet Gas Study-An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers," March 2010, p. 23); ratio successful wells/completed wells is about 0.85; therefore, applying this ratio for wells drilled 2006-2015 = 80 successful wells, 94 completed wells. |
** Based on the yearly price paid by Enstar from 2006-2014 (see Appendix D).
Payback Estimate

$53.5 million invested per year
[10 wells – successful and unsuccessful – drilled per year on average, $5.3 million invested after tax relief.]

14-month payback to return initial investment.

Rate-of-Return Estimate

$107 million – initial investment†
[Investment to drill 20 wells during the first two years.]
$2.2 billion – revenue from sale of 480 Bcf
(-)$275 million – royalty (12.5% of revenue)
(-)$85 million – severance tax ($0.177/Mcf)
(-)$173.2 million – state income tax (9.4% of profit before federal tax)
(-)$265 million – federal income tax (34% of profit after state income tax)‡
(-)$10 million – property tax‡
$1.4 billion (nominal$) – profit
30% – rate-of-return.§

26% – rate-of-return without state tax credits.

† This assumes a tax credit of 50% of total initial investment.
‡ $265 million is based on the oil and gas industry’s average, “effective,” federal income-tax-rate of 17% of profit (i.e. effective tax-rate is tax-rate after depreciation deduction, domestic manufacturing deduction, and depletion allowance).
‡ Assume $20 million property taxes paid by oil and gas industry to the state and local government, then assume 50% allocation or $10 million to gas production (see Anchorage Chamber of Commerce, “The Importance of Cook Inlet Oil and Gas Industry to Southcentral Alaska,” March 2014, p.25).
§ Assuming the 480 Bcf gas is sold in 10 years.
APPENDIX C – PRODUCTION-COST SAVINGS ESTIMATE

A. Methodology

Estimating production-cost saving relies on the following information:

1. Railbelt annual generation and demand
2. Susitna annual generation
3. Cost of producing Susitna power
4. Cost of fuel displaced by hydropower (avoided cost)

Railbelt Electricity Demand and Generation

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual net generation – 5,200 gigawatt hours</td>
<td></td>
</tr>
<tr>
<td>Baseload demand – 415 MW*</td>
<td></td>
</tr>
<tr>
<td>Average monthly peak demand – 725 MW [800 MW –</td>
<td></td>
</tr>
<tr>
<td>average winter monthly peak; 650 MW – average</td>
<td></td>
</tr>
<tr>
<td>summer monthly peak]</td>
<td></td>
</tr>
<tr>
<td>Average annual Railbelt baseload-electricity</td>
<td>3,585 gigawatt</td>
</tr>
<tr>
<td>consumption – 3,585 gigawatt hours</td>
<td></td>
</tr>
<tr>
<td>Average annual intermediate- and peak-electricity</td>
<td>1,615 gigawatt</td>
</tr>
<tr>
<td>consumption – 1,615 gigawatt hours</td>
<td></td>
</tr>
</tbody>
</table>

Susitna Hydropower Generation

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual</td>
<td>2,800 gigawatt</td>
</tr>
<tr>
<td>generation</td>
<td>hours.</td>
</tr>
</tbody>
</table>
Cost of Susitna Hydropower

Cost of power is determined by 1) cost of construction ($5.7 billion); 2) cost of financing ($2.8 billion) and 3) annual cost of operations and maintenance ($29.9 million); amounts are 2014$.

Average Cost (2014$) of Susitna Power†

<table>
<thead>
<tr>
<th>Period</th>
<th>Average Cost (2014$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2029-2038</td>
<td>$0.134/kWh to $0.1083/kWh = $0.12/kWh (average).</td>
</tr>
<tr>
<td>2039-2048</td>
<td>$0.1083/kWh to $0.0712/kWh = $0.09/kWh (average)</td>
</tr>
<tr>
<td>2049-2058</td>
<td>$0.0712/kWh to $0.0571/kWh = $0.064/kWh (average)</td>
</tr>
<tr>
<td>2059-2068</td>
<td>$0.0571/kWh to $0.0265/kWh = $0.042/kWh (average)</td>
</tr>
<tr>
<td>2069-2078</td>
<td>$0.0265/kWh to $0.0068/kWh = $0.017/kWh (average)</td>
</tr>
</tbody>
</table>

Avoided Cost

The “avoided cost” is the cost of generating a kWh with fossil fuel that is replaced by a kWh of hydroelectricity. The avoided cost depends on efficiency of the thermal generation displaced (simple-cycle or combined-cycle) and the type of fuel displaced (gas or oil). The thermal efficiency of a simple cycle-gas power used for peaking is typically 30%-40% compared to about 50% for a combined-cycle power plant used for baseload, intermediate and peaking.

The fuel cost is usually the avoided cost when displacing baseload generation, however, a major reduction in baseload generation avoids O&M expense as well. While fuel cost is the primary avoided cost when displacing stand-alone peak generation, there may also be savings in operation and maintenance, depending upon the amount of time the plant is idled. ‡

The avoided cost of natural gas for Southcentral’s four utilities—Matanuska Electric, Municipal Light and Power, Chugach Electric, Homer Electric—is assumed to be approximately the same, and less expensive than the avoided cost of fuel (various types of fuel) used by Golden Valley Electric.

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† O&M beginning 2029 will increase 5% every year (2.5 percent inflation rate and 2.5 percent escalation rate).
‡ Wayne Dyok, Alaska Energy Authority, Personal Communication, (PFM notes), August 1, 2015.
‡ O&M savings is not estimated in this production-cost savings calculation.
2014 Avoided Cost (MEA, ML&P, CEA, HEA, SEA)

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.05/kWh (natural gas–baseload plant)</td>
<td></td>
</tr>
<tr>
<td>$0.078/kWh (natural gas–peaking plant)</td>
<td></td>
</tr>
</tbody>
</table>

2014 Avoided Cost (GVEA)

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.0784/kWh (blended cost of all fuels used in baseload plants)</td>
<td></td>
</tr>
<tr>
<td>$0.20/kWh (fuel oil–peaking plant)</td>
<td></td>
</tr>
</tbody>
</table>

The avoided cost during the first 50 years of Susitna power (2029 to 2079) will depend on gas price. AEA’s forecasts the wholesale natural gas price in nominal dollars for years 2029, 2039, 2049 and 2059.” In order to estimate production-cost savings, the nominal price must be converted to 2014$ as shown in the following example (inflation rate is 2.5%).

**2029 Gas Price (nominal$ to 2014$)**

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>$6.50/Mcf in 2014 increases to $14.59/Mcf (nominal$) in 2029</td>
<td></td>
</tr>
<tr>
<td>$6.50 at 5.5% (2.5% inflation + 3.0% escalation) over 15 years = $14.59</td>
<td></td>
</tr>
<tr>
<td>$6.50 at 3.0% over 15 years = $10.08, therefore:</td>
<td></td>
</tr>
<tr>
<td>$14.59/Mcf (nominal$) in 2029 = $10.08/Mcf (2014$)</td>
<td></td>
</tr>
<tr>
<td>[$10.08 at 2.5% inflation over 15 years = $14.59]</td>
<td></td>
</tr>
</tbody>
</table>

---

* Alejandra Villalobos Meléndez, Personal Communication, July 31, 2015.
† Avoided cost for peak generation estimate is based on ratio of 35% thermal efficiency for peaking to 50% thermal efficiency for baseload. (average efficiencies system-wide).
## Gas Price Forecast

<table>
<thead>
<tr>
<th>Year</th>
<th>Nominal Gas Price (Mcf)</th>
<th>2014$ Gas Price (Mcf)</th>
<th>Escalation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2029</td>
<td>$14.59/Mcf</td>
<td>$10.05/Mcf</td>
<td>3.0%</td>
</tr>
<tr>
<td>2039</td>
<td>$23.79/Mcf</td>
<td>$12.85/Mcf</td>
<td>2.8%</td>
</tr>
<tr>
<td>2049</td>
<td>$32.78/Mcf</td>
<td>$14.25/Mcf</td>
<td>2.2%</td>
</tr>
<tr>
<td>2059</td>
<td>$43.61/Mcf</td>
<td>$14.51/Mcf</td>
<td>1.8%</td>
</tr>
<tr>
<td>2069</td>
<td>$58.45/Mcf</td>
<td>$14.96/Mcf</td>
<td>1.5%</td>
</tr>
<tr>
<td>2079</td>
<td>$86.52/Mcf</td>
<td>$17.11/Mcf</td>
<td>1.5%</td>
</tr>
</tbody>
</table>

## Avoided Cost (2014$) Forecast for MEA, ML&P, CEA, HEA, SEA

<table>
<thead>
<tr>
<th>Year</th>
<th>Baseload Avoided Cost (kWh)</th>
<th>Peak Avoided Cost (kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2029</td>
<td>$0.078/kWh</td>
<td>$0.12/kWh</td>
</tr>
<tr>
<td></td>
<td><strong>2029-2038 average avoided cost</strong></td>
<td><strong>$0.085/kWh (baseload)</strong></td>
</tr>
<tr>
<td>2039</td>
<td>$0.099/kWh</td>
<td>$0.155/kWh</td>
</tr>
<tr>
<td></td>
<td><strong>2039-2048 average avoided cost</strong></td>
<td><strong>$0.105/kWh (baseload)</strong></td>
</tr>
<tr>
<td>2049</td>
<td>$0.11/kWh</td>
<td>$0.17/kWh</td>
</tr>
<tr>
<td></td>
<td><strong>2049-2058 average avoided cost</strong></td>
<td><strong>$0.111/kWh (baseload)</strong></td>
</tr>
<tr>
<td>2059</td>
<td>$0.112/kWh</td>
<td>$0.173/kWh</td>
</tr>
<tr>
<td></td>
<td><strong>2059-2068 average avoided cost</strong></td>
<td><strong>$0.113/kWh (baseload)</strong></td>
</tr>
<tr>
<td>2069</td>
<td>$0.115/kWh</td>
<td>$0.178/kWh</td>
</tr>
<tr>
<td></td>
<td><strong>2069-2078 average avoided cost</strong></td>
<td><strong>$0.123/kWh (baseload)</strong></td>
</tr>
<tr>
<td>2079</td>
<td>$0.132/kWh</td>
<td>$0.203/kWh</td>
</tr>
</tbody>
</table>

---

* AEA ("Engineering Feasibility Report") forecasts gas price only through 2059. This estimate forecasts 2069 and 2079 gas pricing by assuming 2.5% annual inflation rate, as does AEA, and 1.5% annual escalation rate based on forecasted escalation-rate trend above.

† Avoided cost is forecast using the same percentage increase as the gas price forecast.

‡ “Baseload” avoided cost includes load-following thermal generation; “peak” avoided cost is stand-alone, simple-cycle, thermal generation.
Avoided Cost Forecast (2014$) for GVEA

<table>
<thead>
<tr>
<th>Year</th>
<th>Baseload Avoided Cost</th>
<th>Peak Avoided Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>2029</td>
<td>$0.12/kWh</td>
<td>$0.18/kWh</td>
</tr>
<tr>
<td>2029-2038 average avoided cost</td>
<td>$0.136/kWh (baseload)</td>
<td>$0.204/kWh (peak)</td>
</tr>
<tr>
<td>2039</td>
<td>$0.153/kWh</td>
<td>$0.228/kWh</td>
</tr>
<tr>
<td>2039-2048 average avoided cost</td>
<td>$0.161/kWh (baseload)</td>
<td>$0.24/kWh (peak)</td>
</tr>
<tr>
<td>2049</td>
<td>$0.17/kWh</td>
<td>$0.253/kWh</td>
</tr>
<tr>
<td>2049-2058 average avoided cost</td>
<td>$0.17/kWh (baseload)</td>
<td>$0.26/kWh (peak)</td>
</tr>
<tr>
<td>2059</td>
<td>$0.173/kWh</td>
<td>$0.257/kWh</td>
</tr>
<tr>
<td>2059-2069 average avoided cost</td>
<td>$0.175/kWh (baseload)</td>
<td>$0.26/kWh (peak)</td>
</tr>
<tr>
<td>2069</td>
<td>$0.177/kWh</td>
<td>$0.263/kWh</td>
</tr>
<tr>
<td>2069-2079 average avoided cost</td>
<td>$0.19/kWh (baseload)</td>
<td>$0.282/kWh (peak)</td>
</tr>
<tr>
<td>2079</td>
<td>$0.203/kWh</td>
<td>$0.301/kWh</td>
</tr>
</tbody>
</table>

B. Production-Cost Savings Calculation

The cost savings is the difference between the cost to produce a kWh of hydroelectricity and the cost of fuel to generate a kWh in a thermal power plant.†

The Susitna project would generate power during baseload, intermediate‡ and peak hours throughout the year. The proportion of hydropower generated during baseload, intermediate, and peak hours will depend on how the project is operated. The maximum peak load for each utility occurs during the winter. The peak loads for each utility vary from year-to-year.

* This assumes by 2029, GVEA 1) has natural gas, either from Cook Inlet (AIDEA Interior Energy Project supply) or from the North Slope (Alaska LNG or ASAP pipeline); 2) diesel generation has been converted to natural gas; and 3) the wholesale price of natural gas from 2029 through 2078 will remain about 50% higher than natural gas delivered to CEA, ML&P, MEA, and HEA.
† AEA intends to sell the hydroelectric power from the project for the cost of production; in other words, the price the utility pays for the power delivered from the hydropower project equals the cost of producing the power—the state does not make a profit on the sale of its hydroelectricity to the utilities.
‡ Intermediate is between baseload and peak.
Peak Loads

<table>
<thead>
<tr>
<th>Utility</th>
<th>Peak Load (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Golden Valley Electric</td>
<td>208</td>
</tr>
<tr>
<td>Matanuska Electric</td>
<td>148</td>
</tr>
<tr>
<td>Municipal Light and Power</td>
<td>161</td>
</tr>
<tr>
<td>Chugach Electric</td>
<td>230</td>
</tr>
<tr>
<td>Homer Electric</td>
<td>90</td>
</tr>
<tr>
<td>Seward Electric</td>
<td>10</td>
</tr>
</tbody>
</table>

The sum of the individual utility maximum peak-loads above is about 846 MW; but this maximum peak load seldom, if ever, occurs, because the maximum peak-load of each utility is unlikely to occur at the same time due to the significant variation in winter climate among the major load centers in the Railbelt. The maximum peak load system-wide is about 800 MW. Currently, total system-wide generation to meet base load and capable of load following to meet intermediate and peak is 832 MW.

Combined-cycle, reciprocating engine and hydro power plants can meet base, intermediate, and peak load without loss of efficiency.

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* According to GVEA, peak load is 202 MW, but in 2016 GVEA will serve Clear Air Station, which is about 6 MW. http://www.gvea.com/inside/about
** Ibid.
†† Ibid.
§§ Load following may increase cost of maintenance. Manufacturers are designing systems and components to better survive the cycling environment. Older combined-cycle units can have higher cycling costs compared to a unit specifically designed for cycling (see National Energy Technology Laboratory, Department of Energy, 1) "Impact of Load Following on Power Plant Cost and Performance: Literature Review and Industry Interviews," October 1, 2012; and 2) "Power Plant Cycling Costs," April, 2012).
Generation Capacity

ML&P

Plant 2A–120 megawatts combined-cycle (2016 completion date)
Southcentral–55 MW combined-cycle (jointly owned with CEA)
Eklutna Lake–21.2 MW hydro
Bradley Lake–23.3 MW hydro

CEA

Southcentral–128 MW combined-cycle†
Cooper Lake–20 MW hydro
Bradley Lake–27.4 MW hydro
Eklutna Lake–12 MW hydro

MEA

Eklutna Generating Station–171 MW reciprocating engines
Bradley Lake–12.4 MW hydro
Eklutna Lake–6.8 MW hydro

HEA

Nikiski–80 MW combined-cycle
Bradley Lake–10.8 MW hydro

GVEA

Bradley Lake–5.2 MW hydro
North Pole Expansion–60 MW combined-cycle
Healy #1 & #2–78MW baseload (coal)

SEA

Bradley Lake–0.9 MW hydropower

The 832 MW of generating capacity is more than enough to meet system-wide peak without the need to operate stand-alone, peaking plant once the transmission system is upgraded by 2029. In 2029, with Susitna hydropower, there will be an additional 600 MW of installed capacity, which can be dispatched

Bradley Lake hydropower capacity is allocated among the five utilities.

† Chugach Electric Association’s (CEA) combined-cycle plant is used to meet base, intermediate, and peaking; 7% of CEA’s annual generation is from stand-alone peaking units, but is expected to decrease to 0.5% in 2017 (Mark Fouts, Chugach Electric Association, Personal Communication, December 1, 2015).
anywhere in the system to avoid operating the most expensive thermal power plants; the most expensive thermal power plant would presumably be Golden Valley Electric’s gas-fired plant.† Therefore, when Susitna power becomes available it would eliminate the need for any GVEA natural-gas fired generating capacity.‡ In other words, Susitna hydro would displace about 450 gWh of natural gas-fired generation.§

GVEA Generation (2016)**

<table>
<thead>
<tr>
<th>Total gWh</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,300</td>
<td>Total net annual generation</td>
</tr>
<tr>
<td>594</td>
<td>coal (Healy #1 &amp; #2)††</td>
</tr>
<tr>
<td>78</td>
<td>hydro (Bradley)</td>
</tr>
<tr>
<td>78</td>
<td>wind (Eva Creek)</td>
</tr>
<tr>
<td>400</td>
<td>oil (various power plants)†‡</td>
</tr>
<tr>
<td>150</td>
<td>natural gas (economy purchase from Southcentral utilities)</td>
</tr>
</tbody>
</table>

Therefore, in order to estimate the production-cost savings from the purchase of Susitna power, it is assumed 1) the hydropower project will generate 2,800 gWh annually; 2) the Railbelt transmission grid allows for and utilities agree to economic dispatch of power; 3) most expensive fuel is natural gas delivered to

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† It is not currently possible for the most economic power to be dispatched from one service area to another; so, a utility might be forced to dispatch power from peaking units, even though there is more economical power available elsewhere in the grid. However, by 2029, improvements to the grid will have removed the transmission bottlenecks, thereby allowing the most economic power to be dispatched system-wide. Presumably maintenance on power plants would be done during the non-winter peak months (April through September).

‡ Currently the most expensive thermal plant is GVEA oil-fired generation. Once AIDEA secures an LNG supply for Fairbanks, GVEA would presumably switch from oil to gas, and will replace inefficient thermal units with combined-cycle or reciprocating engines.

§ GVEA could continue to operate natural-gas fired generation when Susitna power becomes available, but this would run counter to the system-wide economic dispatch protocol AEA presumes would be in effect when Susitna dam begins power production.

** 2016 is when Healy #2 begins full-scale operation.

†† This estimate of production-cost savings assumes GVEA’s coal-fired plants will continue to operate after 2029 and that coal will remain the lowest price fossil fuel available for Railbelt generation. Currently coal is about 50% of the cost of natural gas.

†‡ To be generated by gas once gas becomes available.
Fairbanks for baseload generation (450 gWh); and 4) if system load increases, there will be sufficient load-following thermal and hydro capacity to obviate the need for stand-alone peaking units.

Production-Cost Savings (2014$) – 2029-2038

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost (2014$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$61.2 million – cost of natural gas for 450 gWh (GVEA baseload)†</td>
<td>$61.2 million</td>
</tr>
<tr>
<td>($0.136/kWh X 450,000,000 kWh)</td>
<td></td>
</tr>
<tr>
<td>$199.76 million – cost of natural gas for 2350 gWh (baseload avoided cost)</td>
<td>$199.76 million</td>
</tr>
<tr>
<td>($0.085/kWh X 2,350,000,000 kWh)</td>
<td></td>
</tr>
<tr>
<td>$338,000,000 – cost of 2,800 gWh Susitna power §</td>
<td>$338,000,000</td>
</tr>
<tr>
<td>($0.121/kWh X 2,800,000,000 kWh)</td>
<td></td>
</tr>
<tr>
<td>(−)$77,050,000 – annual production-cost savings Susitna power purchase</td>
<td></td>
</tr>
<tr>
<td>(−)$770,500,000 – production-cost savings Susitna power purchase 2029-2038</td>
<td></td>
</tr>
</tbody>
</table>

† For the purpose of this estimate, it is assumed the wholesale price of natural gas from 2029 through 2078 delivered to GVEA, will remain about 50% higher than natural gas delivered to CEA, ML&P, MEA, and HEA.

‡ The AEA 2024 forecast is 874 MW peak load, 5,673 gWh annual generation; and the 2054 forecast is 930 MW peak load, 5,975 gWh annual generation (“Engineering Feasibility Study,” Table 5.7-1, p.5-17, p. 5 -18). AEA projected hourly loads for year 2024 (Bryan Carey, Alaska Energy Authority, “Railbelt Hourly Loads-2024,” Personal Communication, December 28, 2015); based on this projection, winter peak load (i.e. greater than 725MW) will demand 139 gWh. (Note: AEA explains “The load information provide reflects projections derived from data AEA received a few years ago . . .The results of the information derived from the outdated load data provided by AEA will not be accurate.”). Of course, while unlikely, it may be necessary to run thermal peaking generation, if there were a transmission failure that prevented economic dispatch.

§ This is the cost incurred by utilities to purchase Susitna power.
### Production-Cost Savings (2014$) – 2029 through 2078

<table>
<thead>
<tr>
<th>Period</th>
<th>Production-Cost Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>2029-2038</td>
<td>(–)$770,500,000</td>
</tr>
<tr>
<td>2039-2048</td>
<td>$680,400,000</td>
</tr>
<tr>
<td>2049-2058</td>
<td>$1,555,200,000</td>
</tr>
<tr>
<td>2059-2068</td>
<td>$2,076,500,000</td>
</tr>
<tr>
<td>2069-2078</td>
<td>$3,202,000,000</td>
</tr>
</tbody>
</table>

\[ \text{Total production-cost savings (2029 through 2078)} = 6,743,600,000 \]

\[ \text{[$134,872,000/year]} \]

This estimate of $135 million production-cost savings per year is significantly less than AEA’s estimate of $220 million per year.

### C. Production-Cost Savings Calculation Caveats

The above estimate of production-cost savings is based solely on the effect of Susitna hydropower generation on thermal-plant fuel consumption system-wide. This estimate differs significantly from the one MWH Americas developed for Alaska Energy Authority in the “Engineering Feasibility Report.”

- This estimate does not account for avoided O&M expenditures; the MWH estimate does. The MWH calculation of variable O&M costs that would be avoided by Susitna power purchases included fuel and non-fuel operating costs. The non-fuel operating costs are the costs of starting/stopping as well as cycling to follow load. The specific cost savings MWH attributes to avoided fuel and cost savings from starting/stopping/cycling, however, are not clearly stated in its report.

- MWH forecasts use of fuel oil (presumably by GVEA) would continue past 2029, this estimate assumes fuel oil would be replaced by natural gas by 2029.

- This estimate does not (is not able to) calculate avoided cost on an hour-to-hour basis as MWH does with its PROMOD program.

- MWH forecasts electricity consumption to increase 775 gigawatt-hours and peak load to increase about 130 megawatts by 2054. This estimate does not assume any growth in electricity use or peak load, because this does not
affect Susitna generation: regardless of changes in system-wide load, Susitna will only generate up to 2800 gWh annually. Nonetheless, this estimate assumes that load growth would not significantly increase the use of peaking plants, because it is assumed that as peak load grows there is sufficient generation to follow load without requiring stand-alone peaking units to generate.

As the MWH Americas report notes, “total annual net savings to the system will depend on the ultimate cost to develop the Susitna-Watana Project, as well as the future price of natural gas. When the Susitna-Watana Project production cost savings, together with fixed cost savings – because of standby plant retirements – are combined with the annual project fixed costs (including project debt service), the result is the impact on system operating costs of building the project.”
APPENDIX D – ENSTAR COST OF GAS AT CITY-GATE

Commodity Cost vs. ENSTAR Charge

Total Cost per Mcf (Million BTU)

- $12.00
- $10.00
- $8.00
- $6.00
- $4.00
- $2.00
- $0.00

Year
- 2001
- 2003
- 2005
- 2007
- 2009
- 2011 Q2

Cost of Natural Gas

ENSTAR Charge

$8.85