State of Alaska
Department of Natural Resources
Division of Oil & Gas

Bill Walker, *Governor*
Andy Mack, *Commissioner*
Chantal Walsh, P.E., *Director*

Cook Inlet Natural Gas Availability

By

Michael Redlinger, Ph.D., John Burdick, and Laura Gregersen

With Contributions from

Chirag Raisharma and Don Krouskop

March 2018

Alaska Division of Oil and Gas, 550 W. 7th Ave, Suite 1100
Anchorage, Alaska 99501-3560

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Acronyms and Abbreviations

AOGCC	Alaska Oil and Gas Conservation Commission
Bcf	billion cubic feet
Btu	British thermal unit
DEC	Alaska Department of Environmental Conservation
DNR	Alaska Department of Natural Resources
DOE	U.S. Department of Energy
DOG	Division of Oil & Gas
DOR	Alaska Department of Revenue
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EMV	expected monetary value
EUR	estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
GVEA	Golden Valley Electric Association
HDD	heating degree days
HEA	Homer Electric Association
kWh	kilowatt-hour
LNG	liquefied natural gas
Mcf	thousand cubic feet
MEA	Matanuska Electric Association
ML&P	Municipal Light & Power
MMcf	million cubic feet
MWh	megawatt-hour
NPV	net present value
P10, P50, P90	10^{th}, 50^{th}, and 90^{th} percentiles
POS	probability of success
RCA	Regulatory Commission of Alaska
RGIP	recoverable gas in place
UCCI	IHS Upstream Capital Cost Index
UOCI	IHS Upstream Operating Cost Index

Executive Summary

The Cook Inlet basin has served as the Railbelt region's exclusive source of natural gas for nearly sixty years. As oil and gas fields in Cook Inlet continue to age, there is an ongoing need to assess the basin's capacity to meet natural gas demand over the coming years. The purpose of this study is to provide an updated, interdisciplinary (geologic, engineering, and economic) assessment of Cook Inlet gas availability. Specifically, we address the following key questions:

- *What quantities of Cook Inlet gas are recoverable through additional investment, and what is the commercial viability of those potential supplies?*
- *How long can Cook Inlet gas meet existing demand levels, and what prices will be necessary to bring about additional production?*

To answer these questions, this analysis builds on three previous DNR Cook Inlet gas studies (Hartz et al., 2009; Gibson et al., 2011; Munisteri et al., 2015), while incorporating relevant new information. We classify future supplies into two tranches: "baseline production" and "augmented production." Baseline production consists of future production from existing wells. Augmented production is gas that is potentially available but will require additional investment (e.g., drilling new wells). For the augmented production tranche, we first identify potential volumes recoverable through new development, then formulate hypothetical development projects required to produce those volumes, and finally estimate each project's economic viability. The augmented production tranche is limited to potential development in larger gas fields and various conventional exploration prospects; it does not include unconventional resources, such as tight gas, coal bed methane, and others.

There are two main findings of this study:

- There are significant gas volumes potentially available through additional investment and development. We estimate there is 500-800 Bcf of gas in the "augmented production" tranche that is economic to develop at a price range around $6-8/Mcf (real 2016 dollars), which is within the range of Cook Inlet gas prices seen in recent years. Note that these volumes are in addition to baseline production that would come from existing wells. At higher prices, the amount of economically recoverable gas increases, reaching 800-1000 Bcf at prices above $12/Mcf (real 2016 dollars). The key uncertainties that drive the variability in these estimates are costs, production rates, and the rate of return companies require to invest in new projects.
- The Cook Inlet gas volumes identified in this study can satisfy the current demand level of about 80 Bcf/year until around 2030, given the assumptions and simplifications of this analysis. Although these volumes are capable of meeting demand, over time, the natural gas price required to induce additional supply is expected to rise: by the late 2020s, the price required to bring additional production online reaches $10/Mcf or more (real 2016 dollars).

There are important limitations to this study. First, this analysis should not be interpreted as a forecast of Cook Inlet natural gas prices. The results present the economic feasibility of hypothetical development projects under certain assumptions and simplifications; this study does not estimate future natural gas prices, nor is it an assessment of how specific companies that operate in Cook Inlet will evaluate specific projects. Second, this study does not encompass all the gas that remains in Cook Inlet. Additional supplies may come from sources not considered in this report: new development in some smaller existing gas fields, currently unidentified prospects, added compression that increases ultimate recovery, and unconventional resources.

This report is not intended to be a prediction of how Cook Inlet gas supply and demand will play out in future years. Rather it serves as a tool for understanding Cook Inlet's evolving capacity to meet natural gas demand under certain scenarios and assumptions. Accordingly, the results should be considered in the context of the study's scope and in mind of its limitations.

1 Introduction

Natural gas from the Cook Inlet basin is essential to meeting the energy needs of Alaska's Railbelt region. It generates 70% of the Railbelt's electricity, heats over 140,000 homes and businesses, and supplies fuel needed by industrial users.

Cook Inlet fields provided abundant natural gas beginning in the 1960s and lasting several decades. During this time, local utilities secured stable supplies through long-term contracts with prices well below those in the Lower 48, while the basin supported two large industrial users—the Kenai fertilizer and LNG export facilities. The early 2000s marked the beginning of a different era, one characterized by increasing concerns over continued availability of low-cost gas supplies. After remaining relatively level for several decades, gas production began to decline. Long-term contracts between utilities and producers ended, and utilities began evaluating alternatives to locally sourced Cook Inlet gas. Volumes to the fertilizer and LNG export facilities were curtailed, and both plants eventually ceased operations.

In recent years, concerns of an immediate gas shortfall have eased. New companies entering Cook Inlet have discovered additional gas resources and invested in redevelopment within existing fields. Yet Cook Inlet remains a mature basin, where the average field has produced for over thirty years and much of the prolific gas has been developed. Thus, there remains a need to peer into Cook Inlet's next era and assess the basin's capacity to meet future demand.

The purpose of this study is to evaluate the availability of future Cook Inlet natural gas supplies. Specifically, we address the following key questions. First, what quantities of Cook Inlet gas are recoverable through additional investment and what is the commercial viability of those potential supplies? Second, how long can Cook Inlet gas meet existing demand levels, and what prices will be necessary to bring about additional production?

Three previous DNR studies on Cook Inlet natural gas provide the foundation for this analysis. These include the *Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves* (Hartz et al., 2009), *Cook Inlet Natural Gas Production Cost Study* (Gibson et al., 2011), and *Updated Engineering Evaluation of Remaining Cook Inlet Reserves* (Munisteri et al., 2015). We build on the work done in these reports, while incorporating recent developments and relevant new information.

Following Gibson et al. (2011), we classify future supplies into two tranches: "baseline production" and "augmented production." Baseline production consists of future production from existing wells. Augmented production is gas that is potentially available but will require additional investment (e.g., drilling new wells).[1] The augmented production tranche is limited to new development in larger gas fields and various exploration prospects; it does not capture all discovered and undiscovered gas resources in Cook Inlet. Additionally, unconventional resources, including tight gas, coal bed methane and others, are outside the scope of this report.

Section 2 summarizes recent Cook Inlet natural gas demand trends and potential future demand. Section 3 highlights historical supply and describes the approach used to assess future availability. Section 4 presents the results, and Section 5 concludes on the key findings and limitations of this study.

[1] Baseline production also requires additional investment in the form of expenditures to operate and maintain existing wells and facilities; this analysis does not assess the economic viability of the baseline production tranche.

2 Demand

In 1959, Unocal and Ohio Oil[2] drilled the wildcat well Kenai Unit 14-6 in search of oil south of the city of Kenai (Enos and Maier, 2013). They did not find oil, but the well encountered the large gas accumulations that make up the Kenai Gas Field. This marked the first—and to date the largest—gas field discovered in Cook Inlet. Three years later, there were two more large gas finds: the North Cook Inlet field located offshore and the Beluga River field on the west side of Cook Inlet. Although these fields were significant discoveries, their development was hindered by the small local natural gas market in Southcentral.

Two large end users came online to help fully commercialize Cook Inlet's newly-found gas resources. In 1969, Unocal started operations at the Kenai fertilizer plant, which manufactured urea and ammonia using over 50 Bcf per year of natural gas feedstock. In the same year, the Kenai LNG export facility, a joint venture of Phillips Petroleum and Marathon Oil (formerly Ohio Oil), commenced operations. At its peak, the facility exported over 60 Bcf of gas per year to Asia. For more than three decades these two plants consumed more than half of Cook Inlet natural gas production. The remaining consumption was split roughly evenly between electricity generation, gas utilities, and use in oil and gas operations.

2.1 Recent Demand Trends

Over the past fifteen years, the makeup of Cook Inlet natural gas consumption has changed significantly (Figure 1). In the 2000s, gas production began to decline and prices started to climb. Consumption by the Kenai fertilizer plant fell by more than half from 2001 to 2006, and the plant was subsequently mothballed in 2007. Kenai LNG exports declined from about 65 Bcf in 2005 to just 9 Bcf in 2012 (EIA, 2017). No exports occurred in 2013 or 2016, and in 2018 ConocoPhillips sold the mothballed facility to Andeavor (formerly Tesoro).

Total consumption in 2016 was about 78 Bcf: 30 Bcf for electricity generation (39%), 29 Bcf by residential and commercial consumers (36%), 13 Bcf in oil and gas operations (17%), and the remaining 6 Bcf (or 8%) was made up of industrial users and natural gas converted to LNG for shipment to Fairbanks. The following describes recent trends in each of the major end use sectors.

2.1.1 Electricity Generation

In 2015, natural gas was the fuel source for 83% of all electricity generated within the Mat-Su Valley, Anchorage, and Kenai Peninsula and approximately 70% of total electricity generated in the entire Railbelt region. All gas-fired electric plants in Southcentral rely exclusively on Cook Inlet as their fuel source. Additionally, the Fairbanks area receives some electricity generated from Cook Inlet natural gas via electricity sales from Southcentral utilities to Golden Valley Electric Association (GVEA).

[2] Ohio Oil was rebranded as Marathon Oil in 1962.

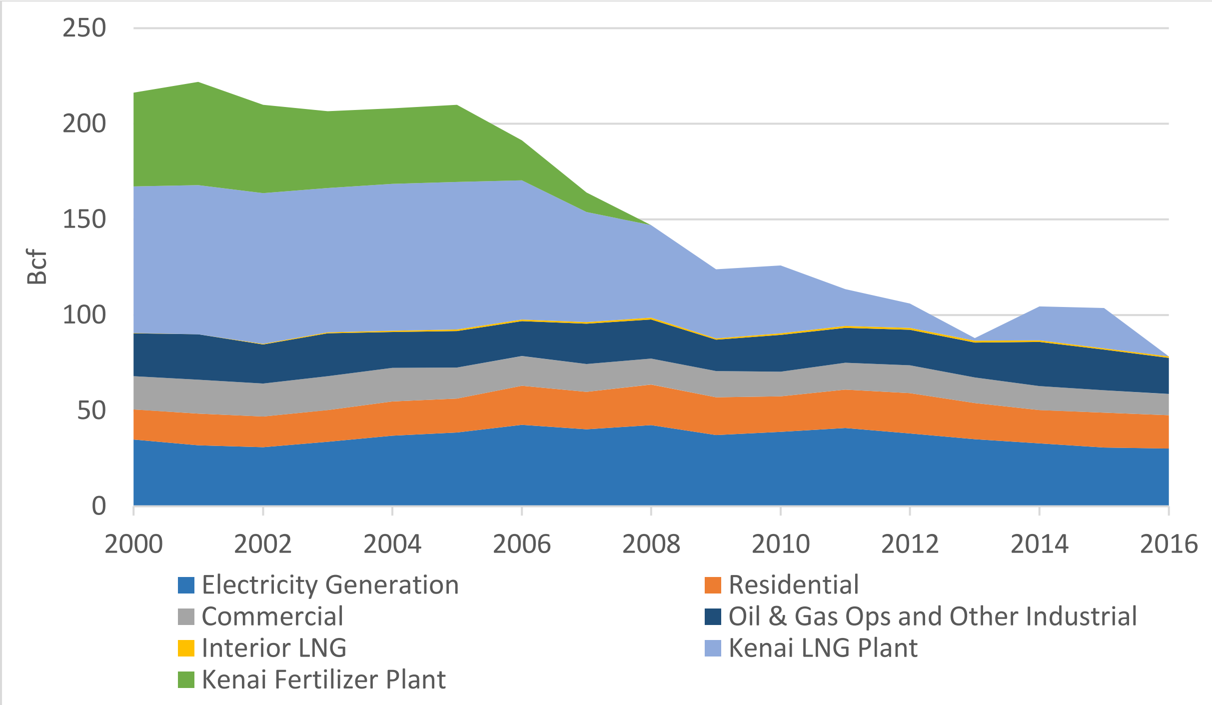

Figure 1. Cook Inlet natural gas consumption by end use (2000–2016)

Sources: Energy Information Administration (EIA) Forms 923 and 176 (EIA, 2017), Regulatory Commission of Alaska (RCA) filings (RCA, 2017), and Alaska Oil and Gas Conservation Commission (AOGCC, 2017)

Natural gas is critical for the Railbelt, but gas consumption in electricity generation has decreased, falling by 28% from 2006 to 2015 (Figure 2). There are two key drivers of this decline. First, electric plants are more efficient. In 2006, 1 kWh of electricity generated by a Southcentral gas-fired electric plant required, on average, 11,000 Btu of natural gas (about 11 cubic feet); in 2015, only 9,500 Btu were required per kWh—a decline of 14%.[3] The primary reason for this efficiency gain is the startup in 2011 of the Southcentral Power Project, a highly efficient gas-fired power plant owned by Chugach Electric and Municipal Light and Power (ML&P). A second driver is that consumers are conserving and using electricity more efficiently. As noted by Fay and Melendez (2014), residential electricity use per capita in Alaska has been on the decline since the 1980s. This trend is due to more efficient lighting, appliances, and space heating as well as consumers responding to higher electricity prices—driven up in part by increased natural gas prices.

[3] An electric power plant's efficiency is measured by its heat rate (Btu/KWh), which is the amount of energy (measured in Btu) required to generate 1 kWh of electricity. A lower heat rate means greater efficiency.

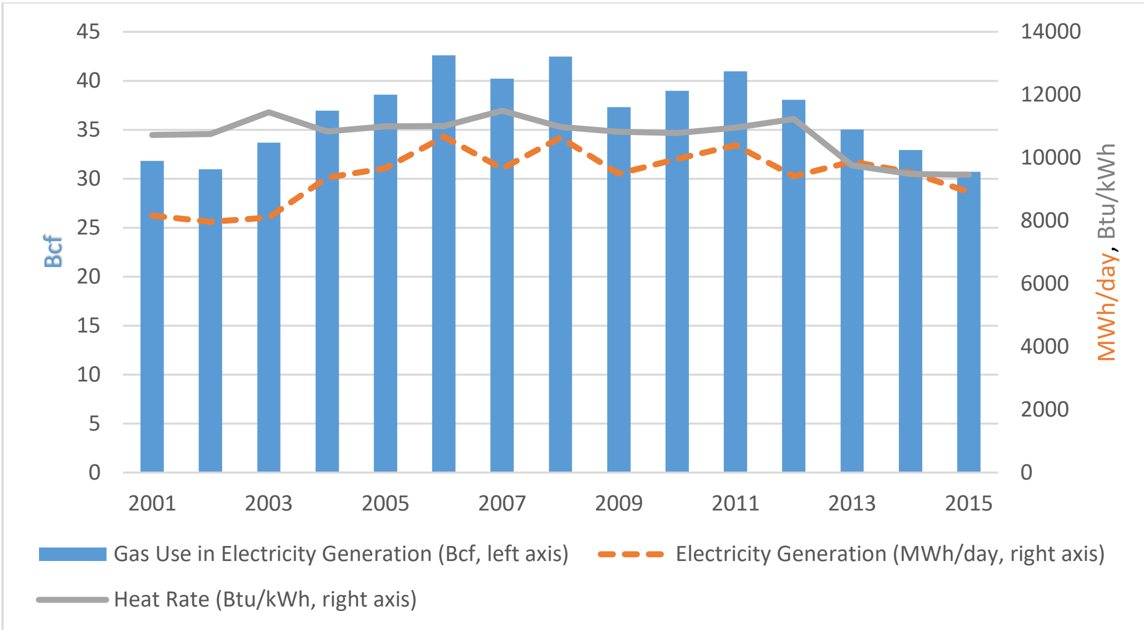

Figure 2. Trends in natural gas use for Southcentral electricity generation

Note: This figure shows gas consumption and gas-fired electricity generation by Southcentral electric utilities. Data sources are EIA Form 923 (EIA, 2017) and RCA filings (RCA, 2017).

2.1.2 Residential and Commercial

The residential sector (Southcentral households) consumed 18 Bcf of natural gas in 2016. Households use gas primarily for space heating, so much of the year-to-year fluctuation in residential consumption can be explained by variation in heating degree days (HDD)—see Figure 3 (left panel). The HDD index measures how cold temperatures are over a given year and is a commonly-used indicator of energy use for space heating.[4] A higher HDD index indicates colder temperatures, and a lower HDD index indicates warmer temperatures.

The number of residential customers grew by 19% from 2005 to 2015, but total residential consumption has been relatively flat. Part of this can be explained by lower HDD index levels in recent years (i.e., relatively warmer winter temperatures). Households are also becoming more energy efficient, which may be the result of consumers responding to higher natural gas prices as well as recent home energy rebate and weatherization programs—see Goldsmith et al. (2012). To show the effect of household energy efficiency gains, Figure 3 (right panel) presents gas use per residential consumer after adjusting for differences in HDD across years (i.e., adjusting for temperature). The "HDD-adjusted use per residential consumer" declined in the late 2000s, suggesting increases in energy efficiency.

[4] HDD measures how cold the temperature is on a given day relative to 65°F. For example, if a day's average temperature is 10°F, the HDD value for that day is 55. The annual HDD index is the sum of the HDD calculated for every day in the year.

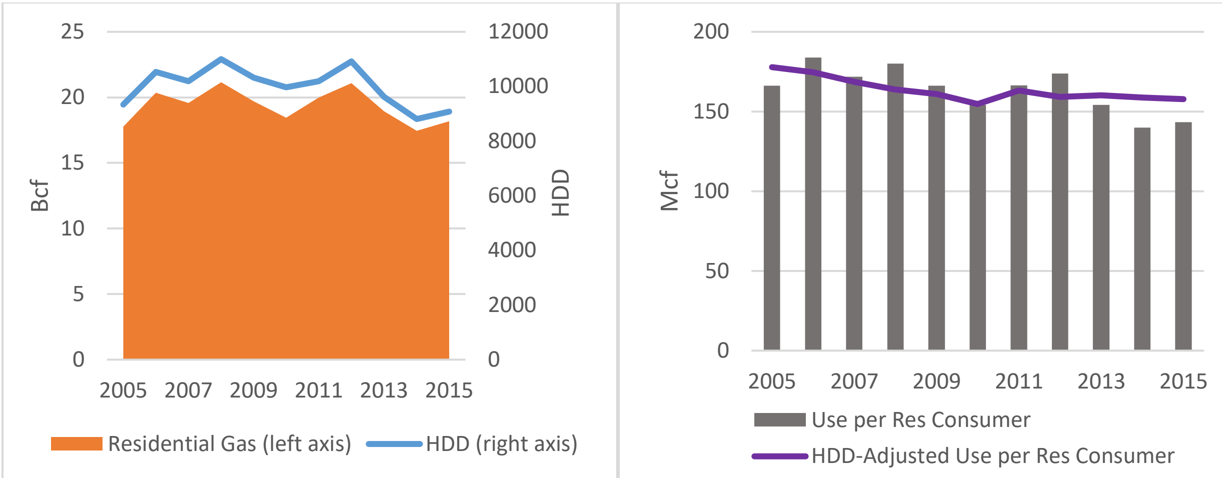

Figure 3. Trends in residential gas consumption (2005–2015)

Note: HDD-Adjusted Use per Residential Consumer normalizes actual use per consumer by multiplying each year's actual use by the ratio of average HDD for 2005-2015 (9,996) and the year's HDD. Data sources are EIA Form 176 (EIA, 2017), RCA filings (RCA, 2017), and the National Oceanic and Atmospheric Administration (NOAA, 2017).

The commercial sector, which consists of businesses, government, and other private and public organizations, also uses natural gas mainly for space heating. Consumption by the commercial sector fell from 15 Bcf in 2012 to 11 Bcf in 2016. Changes in the HDD index and efficiency improvements likely explain much of this decline. In an analysis for ENSTAR, Brown (2014) showed that weather-adjusted consumption per ENSTAR commercial customer has generally decreased over the past 10 to 15 years.

2.1.3 Other End Uses

Other end uses made up nearly 20 Bcf (or 25%) of Cook Inlet natural gas consumption in 2016. Of this amount, just over 13 Bcf was used in oil and gas operations, primarily as fuel for compressors, dehydrators, heaters, and drilling operations. Other industrial end users include Andeavor's Kenai refinery and smaller industrial companies. Total consumption by industrial users is estimated to have been relatively flat in recent years, ranging around 5-6 Bcf per year.

Since 1998, a small amount of Cook Inlet gas has been converted to LNG at Point Mackenzie and sent to Fairbanks, where it is converted back to gas and distributed to households and businesses. In 2016, about 0.8 Bcf was consumed by the Point MacKenzie LNG plant and trucked to Fairbanks. Just over 700 commercial customers made up more than 90% of natural gas use in Fairbanks with the remainder consumed by nearly 500 residential customers.

2.2 Future Demand

This section provides a snapshot of potential future Cook Inlet gas demand. We begin by discussing future consumption by current end uses and then turn to potential sources of incremental demand. We acknowledge the possibility that gas supplies from outside Cook Inlet may be called upon to meet future demand. Additionally, the scenarios of natural gas discussed here assume that natural gas remains the primary fuel source for electricity generation. New generation capacity from hydroelectric, other renewables, or coal could reduce natural gas consumption for electricity generation.

2.2.1 Current Demand Sources

Figure 4 presents a scenario of future Cook Inlet natural gas consumption by end use sector. There is sufficient publicly available information on expected natural gas demand to estimate end use through 2023. Overall consumption by these sectors is expected to remain relatively flat at around 80 Bcf per year.

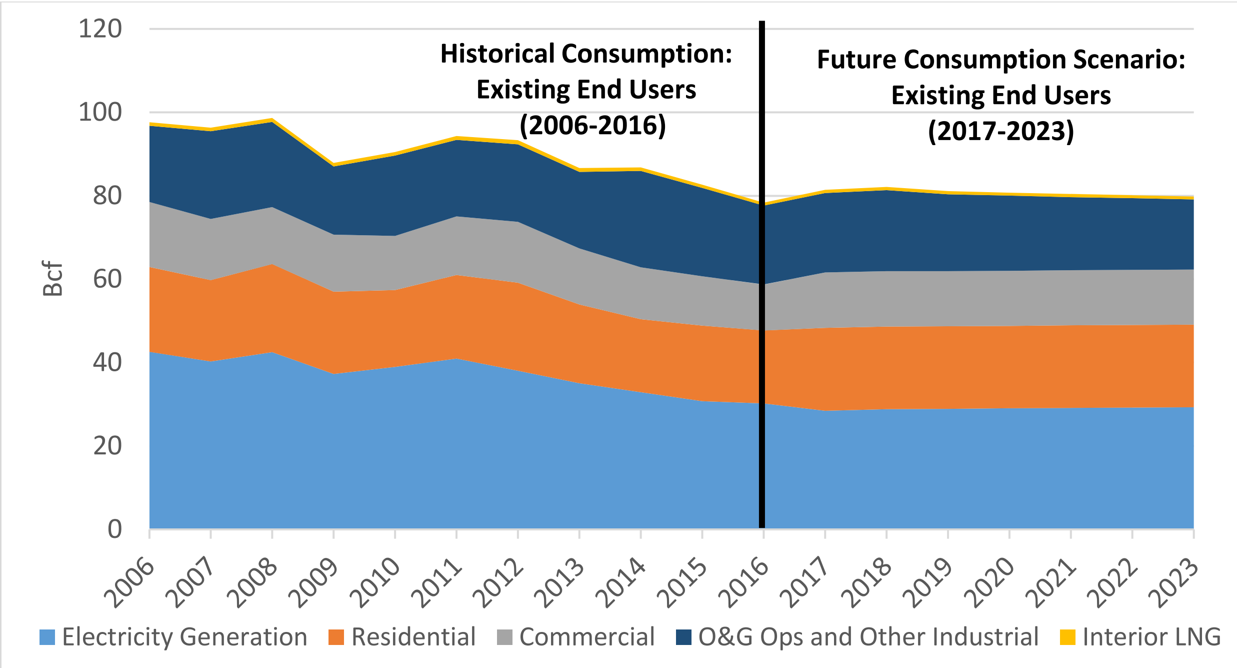

Figure 4. Historical and potential future consumption by existing end uses

Note: This figure shows consumption for only existing end uses and excludes historical consumption by the fertilizer plant and LNG export facility.

The scenario of total commercial and residential consumption is from ENSTAR's projection of 33 Bcf per year demand through 2023 (ENSTAR, 2016). We assume the current demand split of 60% residential/ 40% commercial continues in the future. Although projected residential and commercial gas use is flat, actual consumption will fluctuate from year to year depending on winter temperatures. For the electricity generation sector, consumption is derived from Southcentral electric utility's projections of future demand, which are sourced from various publicly available filings submitted to the Regulatory Commission of Alaska (RCA).[5] Total consumption across all four major utilities—ML&P, Chugach Electric, Matanuska Electric Association (MEA), and Homer Electric Association (HEA)—is expected to be nearly level through 2023 at about 28-29 Bcf per year.

Future gas consumption in oil and gas operations is expected to remain within the range of 12-14 Bcf per year. This projection is based on a simple statistical analysis that uses the historical relationship between Cook Inlet oil production and gas used in operations, along with DOG's Spring 2017 Cook Inlet oil production forecast, to project future levels of gas use in operations. Lastly, demand by the industrial

[5] HEA has publicly available projections through only 2020. For years 2021-2023, it is assumed that HEA demand grows at the same rate projected for 2017-2020 (~1%/year). We also assume that sales to GVEA remain constant at 2016 levels and require about 3 Bcf/year of gas.

sector and Interior LNG are assumed to remain flat at 2016 levels of about 6 Bcf per year. Note that the next section discusses the possibility of additional demand by new industrial users and expanded gas consumption within the Interior.

2.2.2 Sources of Incremental Demand

There are several potential sources of incremental demand for Cook Inlet natural gas. This section does not contain an exhaustive list of all possible demand sources, nor does it assess the likelihood that any particular end use comes online. Rather it provides a summary of publicly available information on potential end uses that are under development or have been discussed in recent years.

The Agrium Kenai fertilizer plant closed in 2007 after nearly four decades of operations. The plant had two production trains with a combined capacity to produce 1.1 million tons of urea and 600,000 tons of ammonia annually using 53 Bcf of natural gas (Agrium, 2007). In recent years, Agrium has explored the possibility of reopening the plant, and in 2016, a State corporate income tax credit was created for in-state facilities that manufacture urea, ammonia, or gas-to-liquids. In 2017, the Alaska Department of Environmental Conservation (DEC) issued wastewater discharge permits to Agrium for the Kenai plant, and the facility reportedly “may resume operations in 2019 depending on the availability of natural gas.” (DEC, 2017). Restarting one train is expected to require about 26-28 Bcf of natural gas per year (Agrium, 2015).

In 2011, ConocoPhillips announced that after 40 years of operations the Kenai LNG Export facility would be mothballed. But later that same year, it decided to resume exports until the facility’s export license expired in March 2013 (ConocoPhillips Alaska, 2014). In 2014, ConocoPhillips was given approval by the U.S. Department of Energy (DOE) to export up to 40 Bcf per year from April 2014 to April 2016. During 2014, five cargos of LNG were shipped from the facility carrying a total of 14 Bcf of gas, and 17 Bcf of gas was exported via six cargos in 2015 (FERC, 2017). DOE granted ConocoPhillips another authorization in February 2016 to export up to 40 Bcf from February 2016 to February 2018, but no exports have occurred since 2015. In 2017, ConocoPhillips again announced plans to mothball the facility, and in 2018, it sold the facility to Andeavor. Figure 5 shows potential gas consumption, if the Kenai LNG export facility were to be restarted sometime in the future, with the number of export cargos ranging from two to six cargos per year; each cargo is assumed to export 2.8 Bcf but consume 3.5 Bcf of gas due to losses that occur in the liquefaction process.

The Donlin Gold project, a joint venture between NOVAGOLD Resources and Barrick Gold, is a proposed gold mine that would be located about 10 miles north of the village of Crooked Creek. The project is expected to produce more than 30 million ounces of gold over its 27-year life (Donlin Gold, 2011). Donlin Gold anticipates using 33 MMcf of natural gas per day (12 Bcf/year) to generate electricity to power the mill and facilities (Bailey, 2017). A proposed 315-mile long pipeline would deliver natural gas from the west side of Cook Inlet to the mine site. The Donlin project is currently in the Environmental Impact Statement (EIS) process, and the final EIS is scheduled to be published by the U.S. Army Corps of Engineers in early 2018. After the final EIS and permitting approvals are complete and a final investment decision is made, Donlin Gold expects that mine construction will take three to four years.

The amount of Cook Inlet gas consumed by households and businesses in Fairbanks is relatively low at just under 1 Bcf per year. Expansion of natural gas consumption in the Interior is another potential demand source. A report by the Interior Energy Project estimated that incremental consumption in the

Fairbanks area by residential and commercial users could reach 2.2 Bcf per year (IEP, 2016). Additionally, the report estimated that consumption by GVEA and the Interior Gas Utility could ramp up to a total of 2.6 Bcf per year. These incremental uses combined could be up to 5 Bcf per year and bring total annual Interior gas consumption to about 6 Bcf.

Figure 5 summarizes the annual consumption possible from these potential sources of additional demand. This figure does not represent a forecast of future consumption; it illustrates how these incremental end uses compare with existing demand.

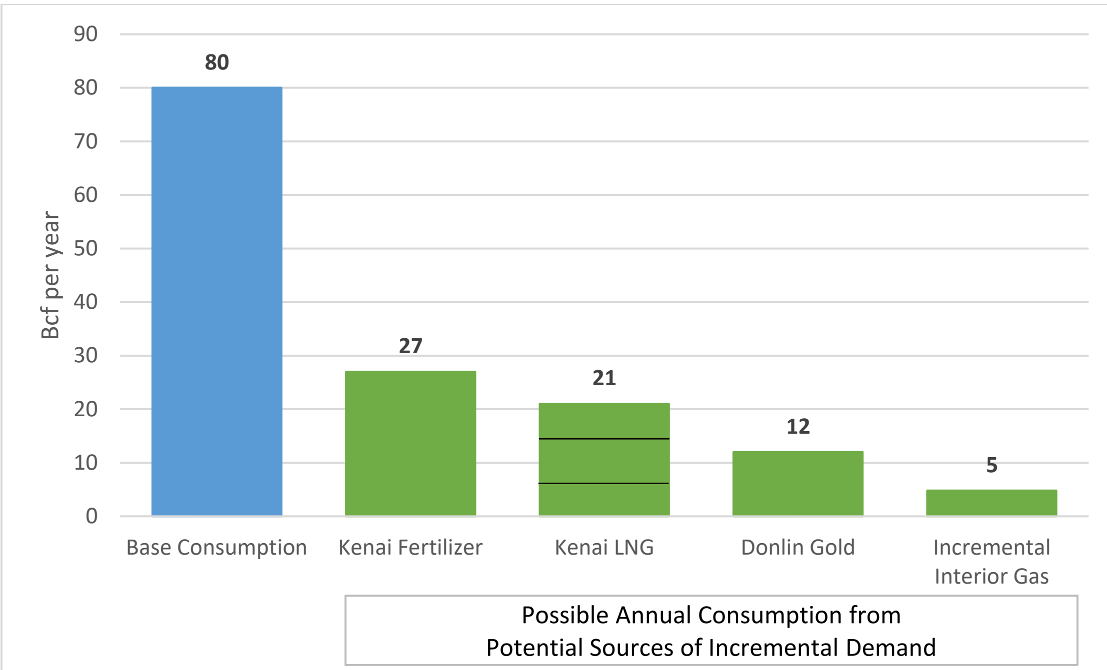

Figure 5. Potential incremental sources of Cook Inlet natural gas demand

Note: Base consumption includes electric generation, residential and commercial use, oil and gas operations, existing industrial users, and current Interior gas use. Kenai LNG consumption with the number of export cargos ranging from two to six cargos per year, where each cargo consumes 3.5 Bcf of natural gas (only 2.8 Bcf is exported due to losses that occur in liquefaction).

3 Supply

3.1 Historical Supply

Oil and gas production started in the Cook Inlet basin after the discovery of the Swanson River field in 1958. Figure 6 shows natural gas production began ramping up in late 1960s as new industrial end users were coming online. Production expanded through the 1970s and ranged around 200 Bcf per year until the mid-2000s, when it began to decline sharply. As of June 30, 2017, the Cook Inlet basin produced approximately 8.505 trillion cubic feet of gas and 1.365 billion barrels of oil.

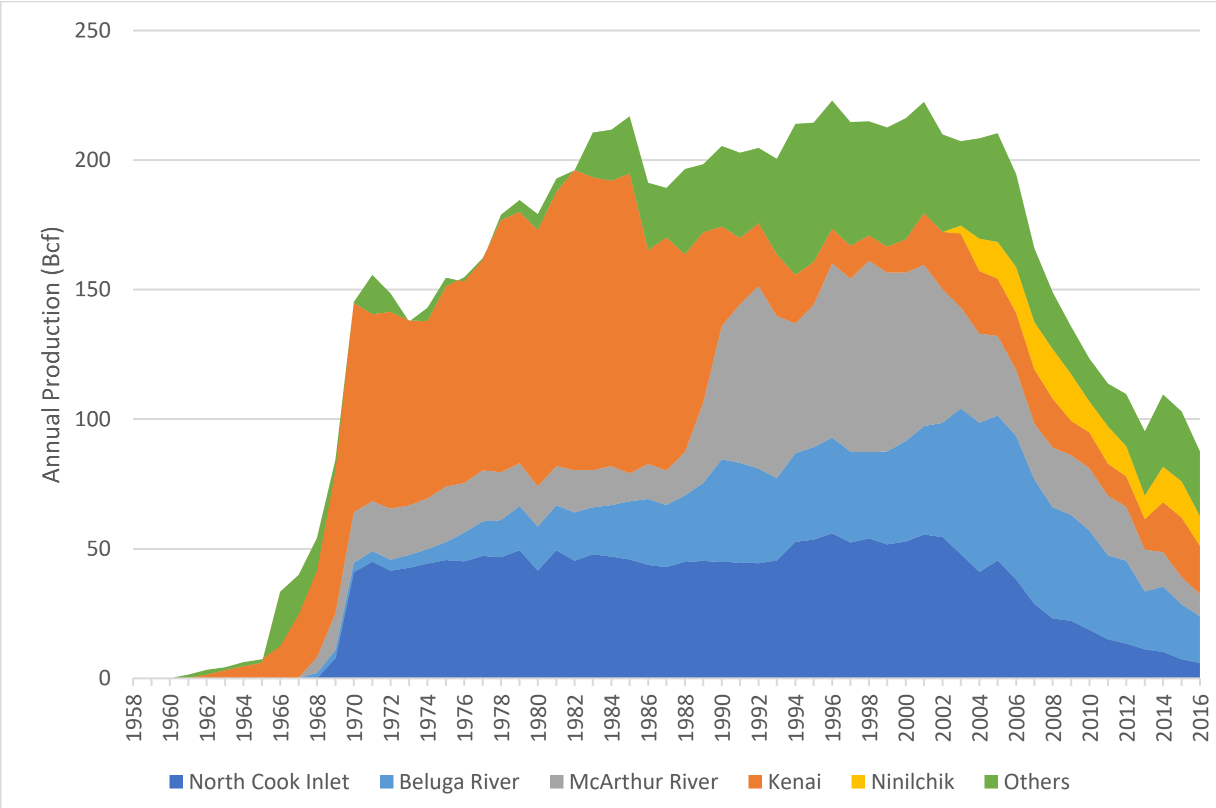

Figure 6. Historical Cook Inlet natural gas production

Note: Data sourced from AOGCC. Production excludes reinjections for enhanced oil recovery at the Swanson River field and storage injections and withdrawals.

Gas has been produced from thirty-five different fields within Cook Inlet, but just four fields—Beluga River, Kenai, McArthur River, and North Cook Inlet— account for 85% of cumulative gas production through 2016. These four fields were among the first discovered and have been producing for more than 50 years. Figure 6 also highlights the 2003 start-up of production at the Ninilchik field, which has become an important source of Cook Inlet gas supply. Additional information on trends in Cook Inlet gas production and activity are discussed in Munisteri et al. (2015).

3.2 Future Supply

This analysis separates future supplies into two tranches: baseline production and augmented production. Baseline production consists of future supply from existing wells and is estimated through a basin-wide decline curve analysis. Most of this study focuses on the augmented production tranche, which encompasses production that is potentially available but will require new investment (e.g., drilling new wells or developing new fields).

Figure 7 is an overview of the approach used to estimate augmented production. The first stage required identifying the recoverable gas volumes that make up the augmented production tranche. The second stage (conceptual development) involved formulating hypothetical gas projects that would be necessary to develop the volumes identified in the first stage; this second stage required estimating production profiles and costs for each project. In the final stage, cash flow models generated economic metrics (rate of return, breakeven price) to measure each project's commercial viability.

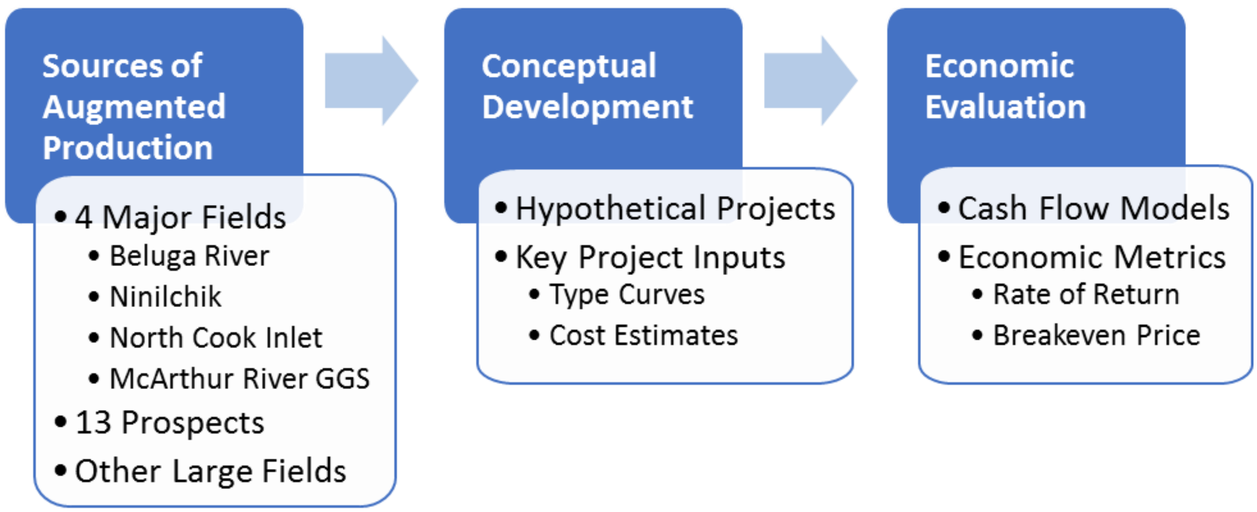

Figure 7. Stages in assessing supplies from the augmented production tranche

3.2.1 Sources of Augmented Production

The primary sources of augmented production are the risked gas volumes from four major Cook Inlet fields (Beluga River, Ninilchik, North Cook Inlet, and McArthur River Grayling Gas Sands [GGS]), as described in DOG's 2009 *Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves* (Hartz et al., 2009). In this evaluation, the 2009 recoverable gas volume estimates for the four major fields were revisited and revised if new well and production information warranted the analyses.

In addition to the four major gas fields, thirteen prospects were identified on state acreage as possible sources of 'future' production as well as other large gas fields that new well, test, and production data show to be productive. For each prospect or large field, high, mean, and low values for original and recoverable gas volumes were estimated from well and seismic data as well as a geologic chance factor. All of these data were provided to the team to incorporate into the economic evaluation.

3.2.2 Conceptual Development

In the conceptual development stage, we determined the wells, facilities, and infrastructure needed to develop the volumes identified as potential sources of augmented production. For the four major fields

(Beluga River, McArthur River Grayling Gas Sands [GGS], Ninilchik, and North Cook Inlet), we began by evaluating the work done in DOG's 2011 *Cook Inlet Natural Gas Production Cost Study* (Gibson et al., 2011). The 2011 study estimated the number of future wells that could be drilled in each of these four fields. In this analysis, we adjusted those estimates down by the number of wells that have been drilled in each field since 2011. Other adjustments were made based on new information available. For example, there has been considerable activity in the Ninilchik field since the 2011 report, and these new developments justified increasing the expected number of future wells that could be drilled at Ninilchik. Additionally, recent studies on the Beluga River field (PRA, 2015; Ryder Scott Company, 2015) were reviewed and considered in estimating the number of future wells possible at Beluga River.

Most of the thirteen exploration prospects identified are greenfield projects that would require new wells, facilities, and infrastructure. We estimated the number of wells required for each prospect by considering the prospect's recoverable gas in place and the amount of gas that could be recovered per well. We determined whether a prospect would need new production facilities and infrastructure (roads and pipelines) depending on its proximity to existing facilities and infrastructure. For the other large fields considered in this analysis (Cosmo, Kenai, and Kitchen Lights), our development assumptions were based on various information about planned or expected development.

The end result was a list of hypothetical projects, which ranged in size from a single well in an existing field to a greenfield project requiring new facilities and infrastructure. The final steps of this stage involved estimating type curves and costs for each project.

Type Curves

The use of type curves is a reliable approach used to evaluate uncertainty in resource estimates for prospects or new fields. A type curve can be described as a collection of analog well production profiles that are averaged together to represent the expected performance of individual new wells for a given pool. The method is grounded on decline curve analysis and in this study, is applied in a probabilistic manner through statistical analysis of historical production data to provide a quantified distribution of reserves estimates with three confidence levels (P10, P50, and P90). This ultimately allows one to evaluate the impacts to economic risk and reservoir behavior.

Type curves were applied in this study using analogous pools and wells for associated prospects. These pools and wells are selected based on:

- Proximity and distance between analog pool and the prospect
- Productive interval (Tyonek, Beluga, etc.)
- Completion type (fracturing, perforating, etc.)
- Production performance (well history, decline, reservoir behavior, etc.)
- Nearby facilities and pipeline tie-ins

As an example, a prospect of interest would most likely involve a nonproducing area near or along trend with one or more potentially analogous pools. Based on the criteria above, the engineer would carefully evaluate pertinent well history files, completion reports, production performance using decline curve analysis, and reservoir behavior characteristics.

A collection of analog wells is carefully chosen and evaluated using associated well data that become representative to a single well for a given pool. The engineer will either accept or withdraw an analog well based on the information and data used.

Upon selecting a representative collection of analog well(s), the type curve function will then produce $P10$, $P50$, and $P90$ type curves using the analog's historical production data and statistical algorithms. Curve-fitting for each confidence level is then applied using the engineer's best judgement.

The Type Curve's resulting Estimated Ultimate Recovery EUR per analog well (for each confidence level) is then multiplied by the number of anticipated wells for a given prospect. This will result in overall pool EUR for a given prospect. The EUR for a given prospect is then compared to the geoscientist's Recoverable Gas in Place (RGIP) volumes using their low, medium, and high estimates. If the EUR confidence level falls within reasonable range relative to the geoscientist's low, medium, and high RGIP estimates, then comparison is deemed positive. If not, the engineers reevaluate and iterate.

Cost Estimates

Cost estimates were derived from both publicly available and confidential data on the costs of recent wells and projects undertaken in Cook Inlet. In some cases, we used estimates from DOG's 2011 *Cook Inlet Natural Gas Production Cost Study* (Gibson et al., 2011). All cost data were escalated to 2016 dollars using either the IHS Upstream Capital Costs Index (UCCI) or the IHS Upstream Operating Cost Index (UOCI), which are widely-used measures of cost inflation in the upstream oil and gas sector (IHS, 2017). An uncertainty range of -15%/+50% was applied to these estimates in the economic evaluation stage.

Capital costs include expenditures for wells, facilities, and infrastructure. We estimated drilling cost per well through a simple approach: [drilling cost per foot] x [well's expected measured depth]. Drilling cost per foot estimates were derived from recent drilling costs in Cook Inlet and escalated to 2016 dollars using the IHS UCCI. Drilling costs estimates were increased for hypothetical projects that are remote or anticipated to require extended-reach wells. Cost estimates for well completion, which involves preparing the well for production by running casing, perforating, and possibly stimulating, were based on the costs of recent natural gas well completions in Cook Inlet.

Facilities include equipment (e.g. separators, dehydrators, and compressors), pads, and platforms (in the case of offshore development). Facility cost estimates were developed using the cost reported for recently-constructed facilities in Cook Inlet and estimates made in DOG's 2011 study. These costs were escalated to 2016 dollar terms and adjusted for the hypothetical project's anticipated production capacity. We estimated cost for infrastructure (i.e., road and pipeline) using a dollar-per-mile estimate derived from data on proposed or recently-constructed gravel roads and pipelines around Cook Inlet.

Operating expenses are incurred during the project's production phase and include labor, fuel, materials and supplies, well workovers, and facility maintenance. Operating cost estimates were made on a dollar-per-well basis and based on historical Cook Inlet operating cost data that were escalated to 2016 dollars using the IHS UOCI.

3.2.3 Economic Evaluation

Figure 8 contains an overview of the economic evaluation stage. The type curves, cost estimates, and other assumptions were put into an Excel-based cash flow model created for each project. The cash flow model calculated the project's annual revenues, costs, royalties, and taxes to arrive at the company's after-tax cash flows. The after-tax cash flows were used to generate two outputs that indicate the project's economic viability: rate of return and breakeven price.

It is important to note that the economic evaluation performed in this report is from the perspective of a hypothetical company evaluating a hypothetical project, and it is not intended to represent how specific companies that operate in Cook Inlet will evaluate specific projects.

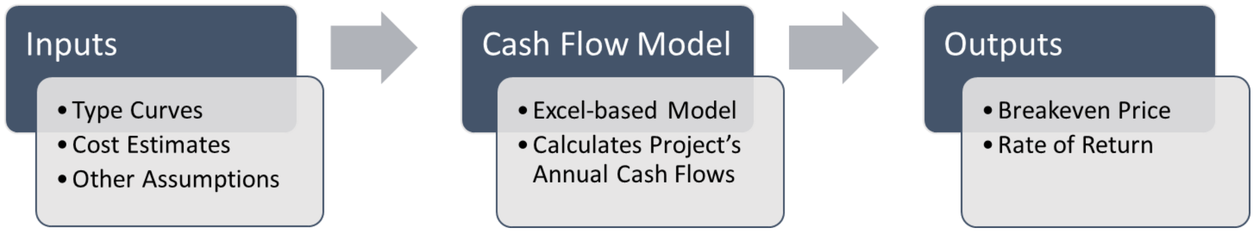

Figure 8. Overview of economic evaluation

Inputs

In addition to the type curves and cost estimates discussed previously, there are several other key inputs to the economic evaluation:

- *Fiscal Regime:* Table 1 summarizes the fiscal regime assumptions. All projects were evaluated based on the laws and regulations in effect as of January 1, 2017. All projects were modeled as occurring after 2017, so expenditures would not be eligible for the production tax credits under AS 43.55.023(a), AS 43.55.023(b), or AS 43.55.023(l).
- *Dry-hole Risk:* In this analysis, a project is a success when moveable natural gas is encountered and production comes online. The probability of success (POS) was set equal to the geologic chance of success discussed in the Conceptual Development section. The probability of a failure (i.e., a dry hole) is equal to 1 - POS.
- *Natural Gas Price:* The results are shown for a range of natural gas prices. In the cash flow modeling, prices were held flat (in real 2016 dollars) over a project's life to calculate the long-term breakeven price for the project.
- *Hurdle Rates:* The results are presented for company hurdle rates of 10%, 15%, and 20% (real). The hurdle rate represents the minimum rate of return a company requires to invest in the project. Because cash flows are calculated in real 2016 dollar terms (i.e., effects of inflation are not included), these are real, as oppose to nominal, hurdle rates.
- *Storage:* Sufficient storage capacity is assumed to exist so that well production does not have to be curtailed due to seasonality of demand. The analysis does not include the cost of storage.

Table 1. Fiscal regime assumptions used in the economic evaluation

Fiscal Regime Input	Description
Royalty	Fixed rate royalty of 12.5%.
Production Tax	The lesser of 1. $0.177 per Mcf **or** 2. For 2014 to 2021, 35% of the annual production tax value (PTV). For 2022 and after, 13% of the gross value at the point of production (GVPP). PTV = GVPP - Qualified Adjusted Lease Expenditures GVPP = [Wellhead Value per Mcf] x [Taxable Production] Qualified Adjusted Lease Expenditures include certain qualified capital and operating expenditures allowed under AS 43.55.165. All projects are assumed to start after 2017, so expenditures are not eligible for credits under AS 43.55.023(a), AS 43.55.023(b), or AS 43.55.023(l).
Petroleum Property Tax	2% of assessed value, approximated as tangible capital adjusted for depreciation and utilization with a 20% floor.
State Corporate Income Tax	9.4% of taxable income, approximated as net revenue less operating expenses, production tax, property tax, and depreciation. Depreciation is estimated using an 11-year double declining balance depreciation schedule.
Federal Corporate Income Tax	35% of taxable income, approximated as net revenue less operating expenses, production tax, property tax, state corporate income tax, and depreciation. Depreciation is estimated using 7-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. The company is assumed to be an independent producer under the Internal Revenue Code and thus eligible to expense intangible drilling and development costs (IDCs).

Cash Flow Model

After-tax cash flows (i.e., revenues – royalties – costs – taxes) were calculated with Excel-based models for two cases: 1) a success case where moveable hydrocarbons are encountered and production comes online and 2) a failure case where the well is a dry hole. In the failure case, there is no production, so the cash flows consist mainly of drilling and abandonment costs and any associated tax impacts. Note that the success case is a "success" in the sense that moveable hydrocarbons are discovered; it is not necessarily mean that the project is a commercial success.

Next, the net present value (NPV) of each case was calculated. To calculate NPV, cash flows that occur in future years are discounted to the present with the use of a discount rate (e.g., 10% per year). The discount rate represents a typical company's opportunity cost of capital, and it is the rate of return the company could have earned had it forgone the project and invested elsewhere. Discounting is performed in economic evaluation because a dollar earned in the future is worth less than a dollar today—a dollar today could be invested now and generate a return (Stermole and Stermole, 2014). The NPV of the success case (denoted by NPV_S) and the NPV of the failure case (NPV_F) are calculated by summing up the "discounted cash flows" estimated for each case.

Lastly, the expected monetary value (EMV) of each project was calculated as the probability-weighted average of NPV_S and NPV_F. That is, EMV = NPV_S x POS + NPV_F x (1-POS). Note that the NPV_S is weighted by the probability that a success occurs (POS) and the NPV_F is weighted by the probability of a failure (1-POS). The EMV thus accounts for the dry-hole risk inherent in any project. When the EMV is positive, a project is economically viable, and when the EMV is negative, the project is uneconomic.

Outputs (Economic Metrics)

Two economic metrics were quantified from the cash flow models: rate of return and breakeven price. The rate of return, for the purposes of this analysis, is the value of the discount rate that sets the project's EMV equal to zero. If a project's rate of return exceeds the company's hurdle rate (the minimum rate of return required), the project is economically viable. The breakeven price is the natural gas price needed to make a project's EMV equal to zero. At prices above the breakeven price, the project has a positive EMV and is economically viable; at prices below the breakeven price, the EMV is negative and the project is not economic.

The results of the economic analysis are sensitive to the inputs and assumptions of the cash flow models. Given the uncertainty over costs and production, we performed a Monte Carlo analysis to develop a probabilistic range for the outputs. Three key inputs were varied: production, capital expenditures, and operating expenses. Production was varied according to the *P*10, *P*50, and *P*90 type curves discussed previously. Costs estimates were varied with a -15%/+50% uncertainty range that followed a triangle distribution, which is commonly-used distribution for cost estimates. Additionally, results are presented with different hurdle rates and natural gas prices.

Table 2. Summary of economic metrics

Economic Metric	Units	Definition	Calculation	Decision Rule
Net Present Value (NPV)	$	Current value of a stream of future cash flows	Sum discounted future cash flows	NPV > 0: economic NPV < 0: uneconomic
Expected Monetary Value (EMV)	$	Probability-weighted average of all possible NPVs	Sum "expected" (probability-weighted average) discounted cash flows	EMV > 0: economic EMV < 0: uneconomic
Rate of Return	%	The discount rate that makes the EMV=0	Numerical methods	Rate of return > hurdle rate: economic Rate of return < hurdle rate: uneconomic
Breakeven Price	$/Mcf	Price that makes the EMV=0	Numerical methods	Price > Breakeven Price: economic Price < Breakeven Price: uneconomic

Notes:

1. The hurdle rate is the minimum rate of return that a project must yield to be considered economically viable.

2. Both the rate of return and breakeven price are solved through numerical methods that iterate through different possible discount rates/prices until the EMV becomes zero.

3. The typical definition for rate of return is the discount rate that sets NPV=0. For this analysis, it is the discount rate that sets EMV=0.

4 Results

Our results begin by focusing solely on the augmented production tranche. As discussed in Section 3, the augmented sources of supply consist of 1) new development wells in four major fields (Beluga River, McArthur River GGS, Ninilchik, and North Cook Inlet), 2) thirteen exploration prospects, and 3) new development in three other large fields (Cosmo, Kenai, and Kitchen Lights). We then combine both baseline and augmented production tranches and give a basin-wide picture of Cook Inlet supply and demand.

4.1.1 Augmented Production

Figure 9 contains “cumulative availability curves”[6] for the augmented production tranche. The curves depict the cumulative volume of gas that is economic to produce (assuming a 10% real hurdle rate) at different natural gas prices. For example, at a price of $8/Mcf, the median (P50) case in Figure 9 shows about 700 Bcf of gas is economic to produce. As expected, the curves are upward sloping: as prices increase, more supply becomes economic. Eventually, the curves become very steep because once the relatively low-cost gas is depleted, what remains are higher-cost projects with lower resource potential.

The 10th percentile, 50th percentile (median), and 90th percentile curves in Figure 9 come from the Monte Carlo analysis, and the variation across percentiles is driven by uncertainties about production and cost. At an $8/Mcf price, for example, about 800 Bcf and 600 Bcf are economic to produce in the 10th and 90th percentile cases, respectively. Stated differently, given the assumptions (and simplifications) of this analysis, we are 80% confident that the volume of gas, in the augmented production tranche, that is economic to produce at $8/Mcf lies between 600 and 800 Bcf. To put these volumes and prices in context, current annual Cook Inlet gas consumption is about 80 Bcf per year, and DOR’s prevailing value for Cook Inlet natural gas, which is a weighted average of sales to publicly regulated utilities, has ranged around $5-7 per Mcf over the past five years (see Figure A-4 of Appendix).

The cumulative availability curves in Figure 9 are estimated under the assumption that companies require a 10% real rate of return. Figure 10 depicts the median case cumulative availability curves under 10%, 15%, and 20% real hurdle rates. Depending on the price level one is looking at, varying the hurdle rate can materially change the results. For example, at $8/Mcf, the range is relatively tight: the amount of gas economic to produce in the median case is about 700, 670, and 650 Bcf at hurdle rates of 10%, 15%, and 20%, respectively; at a price of $6/Mcf, the range is much wider: 610, 530, and 400 Bcf. Figures A-1 and A-2 of the Appendix show additional cumulative availability curves under 15% and 20% hurdle rates.

[6] The concept of the “cumulative availability curve” is described by Tilton (2002) and is typically used to assess the global availability of a mineral resource. Although it is used differently in this analysis, it serves as a useful way to present quantities and price in a single graph.

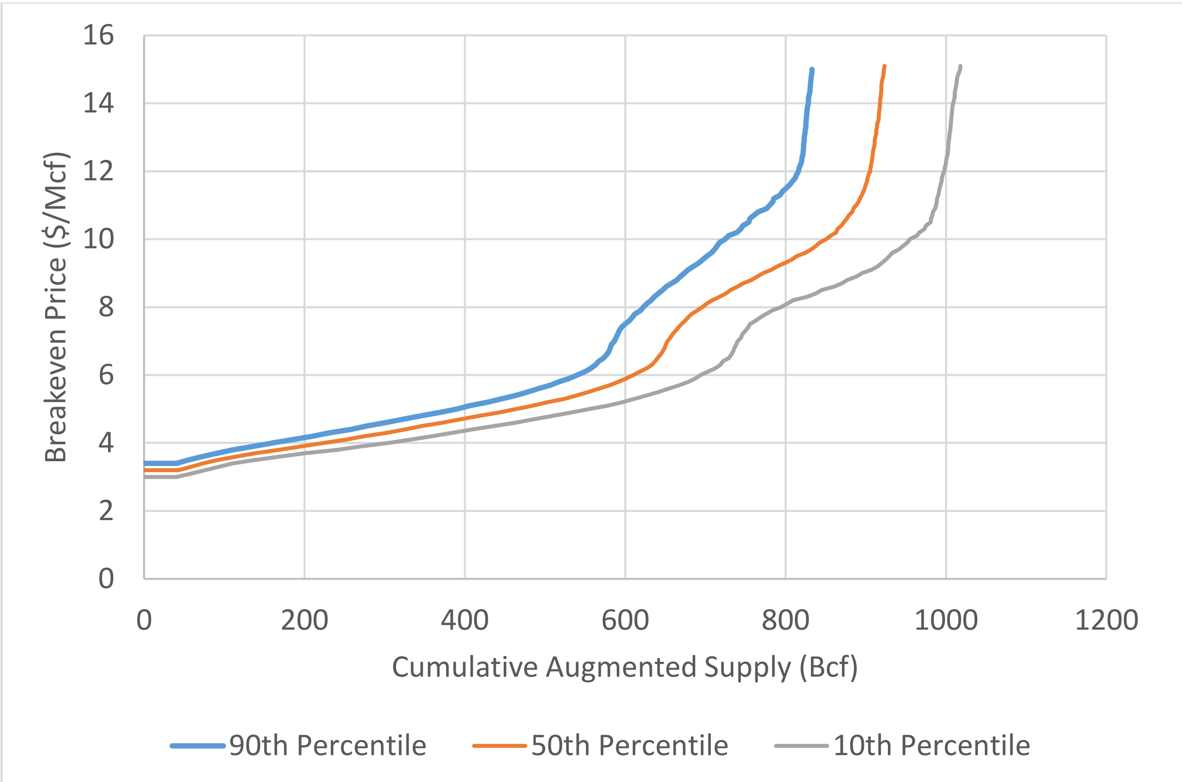

Figure 9. Cumulative availability of augmented production (10% real hurdle rate)

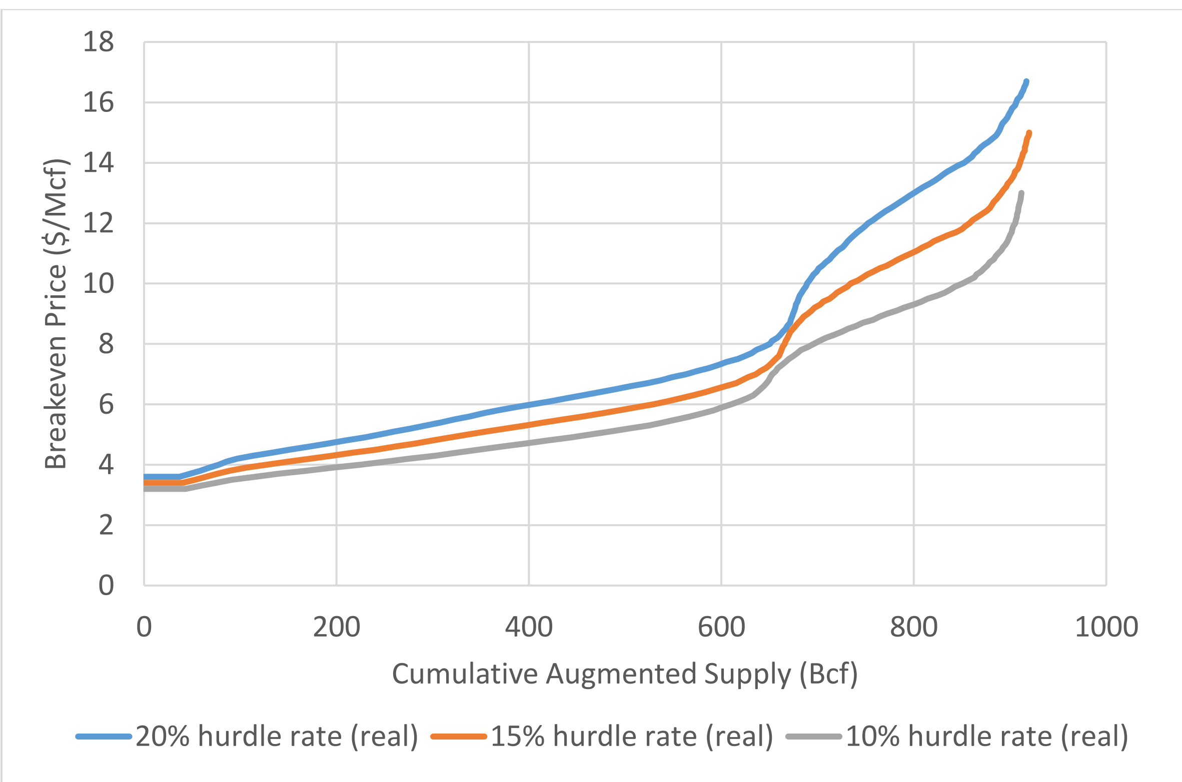

Figure 10. Cumulative availability of augmented production under varying hurdle rates (median case)

Figure 11 offers another way to assess the economic viability of developing future gas supplies. It shows the cumulative supply available from the augmented production tranche at rates of return and assuming a $7/Mcf natural gas price. For example, in the median case, at a price of $7/Mcf, there is about 560 Bcf of undeveloped gas that yields a real rate of return of at least 20% Put another way, if companies require a 20% real rate of return, there is about 560 Bcf of gas economic to produce at $7/Mcf in the median case. The choice of $7/Mcf is to some degree arbitrary but within the range of Cook Inlet natural gas prices in recent years (DOR, 2017).

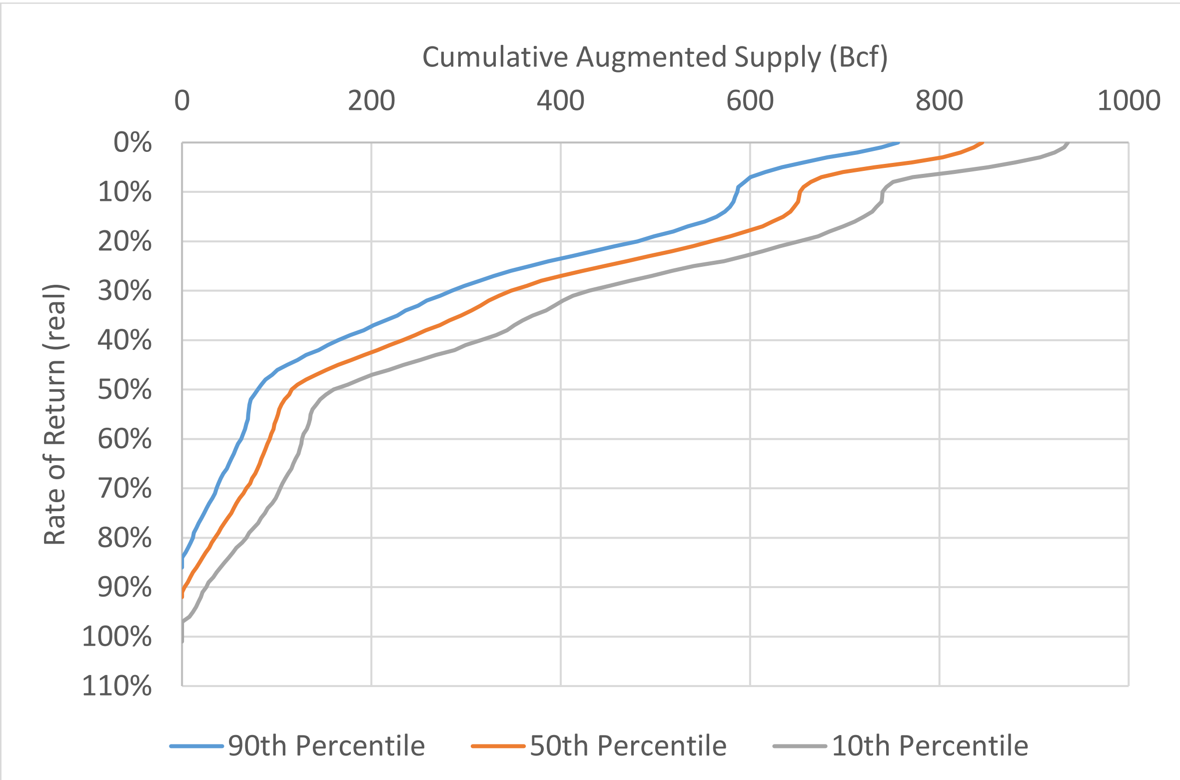

Figure 11. Rate of return (real) for cumulative supplies from augmented production

Note: This figure assumes a natural gas price of $7 per Mcf (real 2016$).

Note that the cumulative availability curves show supplies available over the entire life of all projects; only a portion of the volumes in these figures would be available over the next decade. Also, the cumulative availability curves include only augmented production and not the baseline production tranche. The following section incorporates baseline production and addresses the timing in which supplies can come online.

4.1.2 Supply and Demand Balance

Figure 12 displays the balance of supply and demand in Cook Inlet over the coming years. Demand is expected to remain around 80 Bcf per year (see Section 2). Supply comes from both the baseline production tranche, which is estimated through a basin-wide decline curve analysis, and the augmented production tranche.

Over time, as baseline production falls, gas from augmented production tranche must be developed to meet total demand. We model Cook Inlet as having a hopper of gas projects that can be brought online as needed to meet demand. The projects with the lowest breakeven prices (i.e., the most economic ones) are assumed to come online first, followed by projects with progressively higher breakeven prices. Eventually, after all projects are developed (i.e., the hopper is emptied), total Cook Inlet production falls below consumption. Figure 12 shows that in the mean case, this shortfall begins in 2030. When the 10th and 90th percentile augmented production cases are combined with the baseline production scenario, the shortfall begins in 2033 and 2029, respectively. The baseline production is held fixed across all cases, so these are not the true 10th/90th percentile cases for the initial shortfall year.[7] The true 10th/90th percentiles would have a wider range, reflecting greater uncertainty about when a shortfall might occur. Note that this analysis incorporates only uncertainties over costs and production, and not all the potential uncertainties surrounding future gas supply and demand.

Figure 13 shows how the natural gas price needed to induce additional production changes over time. It assumes 80 Bcf per year of gas demand and presents results under different hurdle rates. This chart is best understood with an example: in 2028, some project will have to come online (from the imaginary hopper) in order to meet the last Mcf of demand. Figure 13 shows that this project is estimated to have an $8.5/Mcf breakeven price (assuming a 15% real hurdle rate). That is, $8.5/Mcf is the minimum price required to make the project economic. Since we assume the most economic projects are developed first, over time the breakeven prices increase. Thus, to satisfy the 80 Bcf per year demand, the natural gas price required to induce new investment and supply is expected to rise in the future. Note that Figure 13 shows the estimated breakeven price for the mean case; Figure A-3 of the Appendix presents the same chart but with the 10th percentile (high side case) breakeven prices.

There are two key takeaways from Figure 12 and Figure 13. First, given the assumptions and simplifications of this analysis in the mean case, the volumes of Cook Inlet gas identified in this study can satisfy 80 Bcf/year demand until around 2030. Second, for much of the study period, the prices needed to induce additional investment and supply are roughly within the range of prices observed in recent years. But beginning in the late 2020s, the price required to bring new production online rises above current levels, eventually exceeding $10/Mcf.

[7] This would require incorporating the baseline production into the same Monte Carlo analysis that generated the augmented production cases and was not feasible to do in the current study.

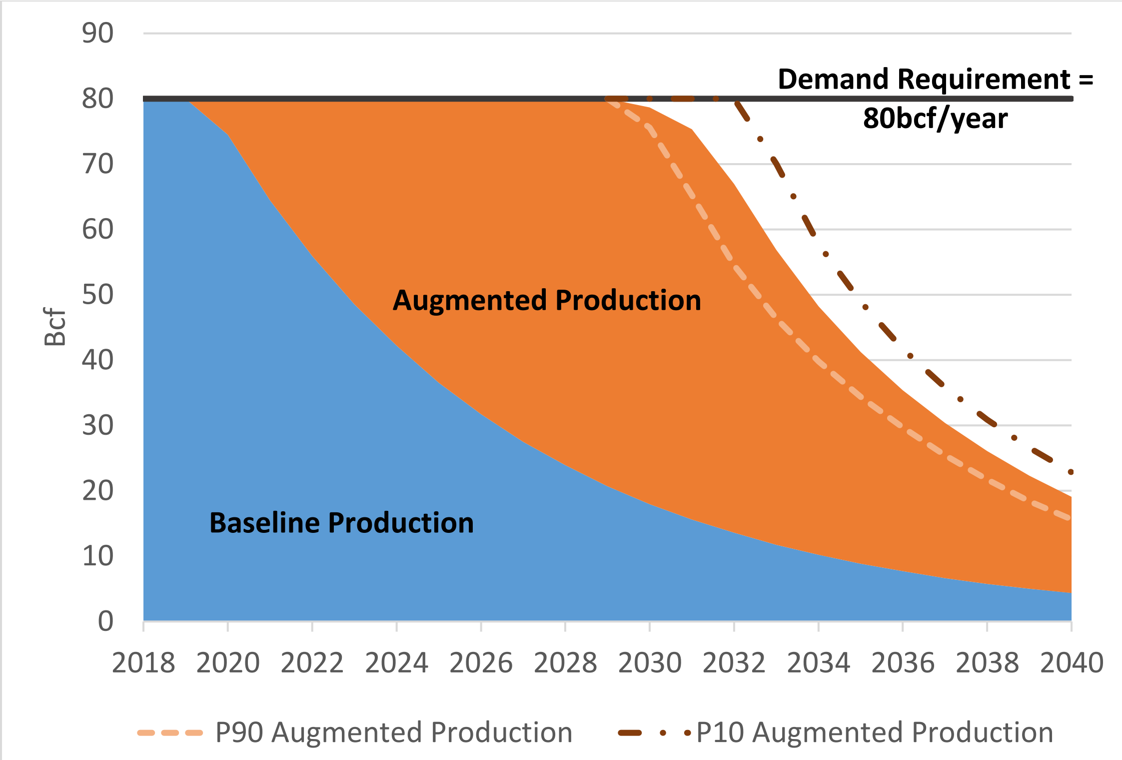

Figure 12. Cook Inlet supply and demand balance

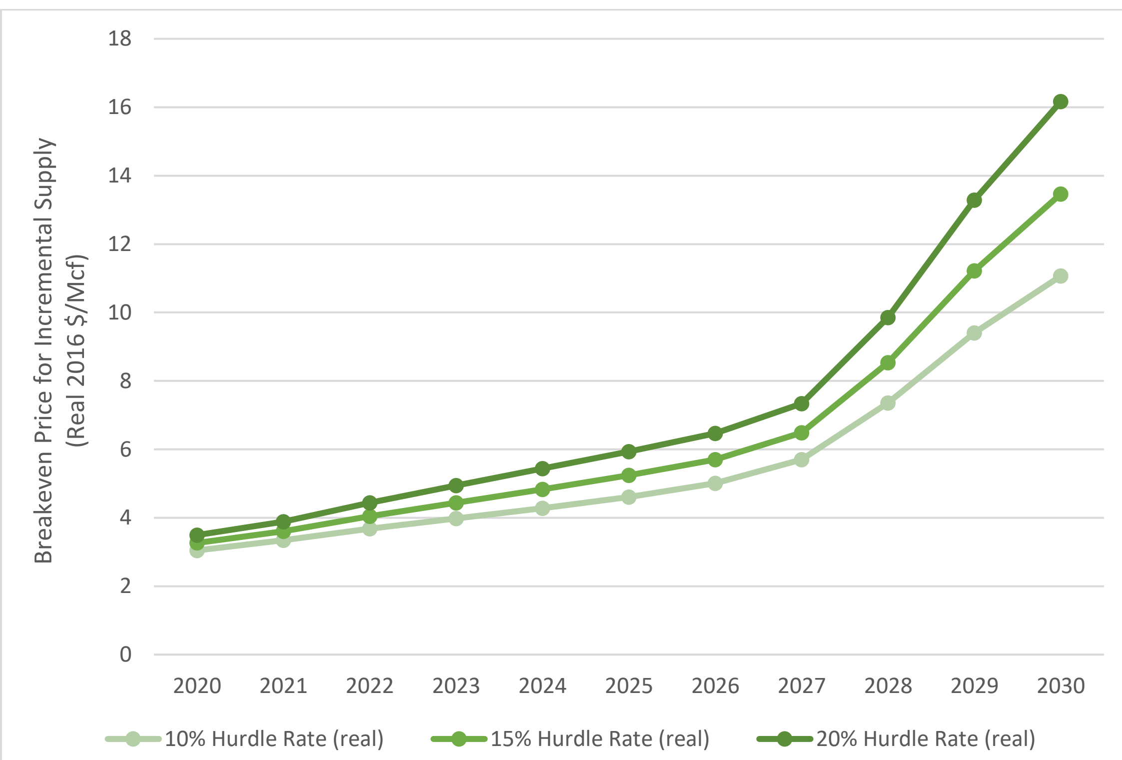

Figure 13. Natural gas breakeven prices (mean case) over time under 80 Bcf/year demand

There are important caveats to note when interpreting these results. First, these are not forecasts of natural gas prices that would be observed between producers and end users (e.g., utilities, oil and gas companies, refineries, mines, etc.). Rather, these are estimates of the minimum price needed (in real 2016 dollars) to make hypothetical projects economic under the assumptions and simplifications of this analysis. Second, the analysis assumes that demand is flat at 80 Bcf per year. Actual demand will certainly be different, and electric and gas utility consumption may change over time and new end uses may start up. Moreover, if prices rise in the future, natural gas consumption may fall as consumers respond to higher prices by conserving and using energy more efficiently. Third, this study does not account for every Mcf of gas left in Cook Inlet. New supplies may come from other sources that are not captured in this analysis: new wells drilled in smaller existing fields, new field discoveries, increased compression that may enhance production from existing fields, and unconventional gas resources, such as tight gas, coal bed methane, and coal gasification.

5 Conclusion

This report set out to answer the following key questions: first, what quantities of Cook Inlet gas are recoverable through additional investment and what is the commercial viability of those potential supplies? Second, how long can Cook Inlet gas meet existing demand levels, and what prices will be necessary to bring about additional production? To help answer these questions we separated future supplies into two tranches: baseline production, which consists of future supply from existing wells, and augmented production, which is potentially available but will require new investment.

There are two main findings. First, there are significant gas volumes potentially available through additional investment and development. We estimate that 500-800 Bcf of additional gas is economic to develop at a price range around $6-8/Mcf (real 2016 dollars). Note that this estimate includes only the augmented production tranche and is in addition to baseline production. At higher prices, more volumes are economic to develop: the amount of gas recoverable eventually reaches 800-1000 Bcf at prices above $12/Mcf. Uncertainties over costs, production, and the rate of return companies require to invest in new projects drive the variability of these estimates. Second, under the assumptions and simplifications of this analysis, in the mean case, the volumes of Cook Inlet gas identified in this study can satisfy 80 Bcf/year demand until around 2030. But over time, the natural gas price required to induce additional supply increases: in the late 2020s, the price required to bring additional production online reaches $10/Mcf or more (real 2016 dollars).

Just as important as the findings of this study are its limitations. First, this analysis is not a forecast of Cook Inlet natural gas prices. Instead, the results shown are breakeven prices (in real 2016 dollar terms) estimated for hypothetical projects under the assumptions and simplifications of this analysis; it is not an assessment of how specific companies that operate in Cook Inlet will evaluate specific projects. Second, this study does not encompass all volumes of gas that remain in Cook Inlet. Additional Cook Inlet supplies may come from other sources not considered in this report: new development in some smaller existing gas fields, other undiscovered prospects, added compression that increases ultimate recovery, and unconventional resources.

The goal of this study has been to build upon previous Cook Inlet gas studies, incorporate new information, and ultimately provide an updated, interdisciplinary (geologic, engineering, and economic) assessment of Cook Inlet gas availability. This report is not intended to be a crystal ball for the future of Cook Inlet natural gas. Rather it is a tool for understanding how Cook Inlet supply availability might evolve in the coming years under different scenarios and assumptions. Accordingly, the results should be considered in the context of the study's scope and in mind of its limitations.

Cook Inlet has served as Southcentral Alaska's exclusive source of natural gas for nearly 60 years. Despite the basin's age, it has shown considerable resilience in recent years—with the help of new discoveries and redevelopment efforts. Understanding how long this resilience can continue is vital to the many Alaskans that rely upon Cook Inlet for their energy needs.

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Appendix

Figure A-1 and Figure A-2 show the cumulative availability curves for the augmented production tranche when assuming 15% and 20% real hurdle rates, respectively. These charts can be compared to Figure 9, which shows the cumulative availability curves when a 10% real rate of return is required. The curves depict the cumulative volume of gas that is economic to produce. Because these charts assume a higher hurdle rate, the breakeven prices are higher than those in Figure 9.

Figure A-3 is similar to Figure 13 except that it presents the 10th percentile (high side case) breakeven price rather than the mean breakeven price. This figure demonstrates how the natural gas price needed to induce incremental production changes over time. For example, in 2028, the 10th percentile value for the breakeven price for the marginal source of gas production is \$11/Mcf (assuming a 15% real rate of return is required); compare this to Figure 13, which shows the mean breakeven price in 2028 is \$8.5/Mcf (assuming a 15% real hurdle rate).

Figure A-4 shows the Cook Inlet natural gas prevailing value as calculated quarterly by DOR (DOR, 2017).

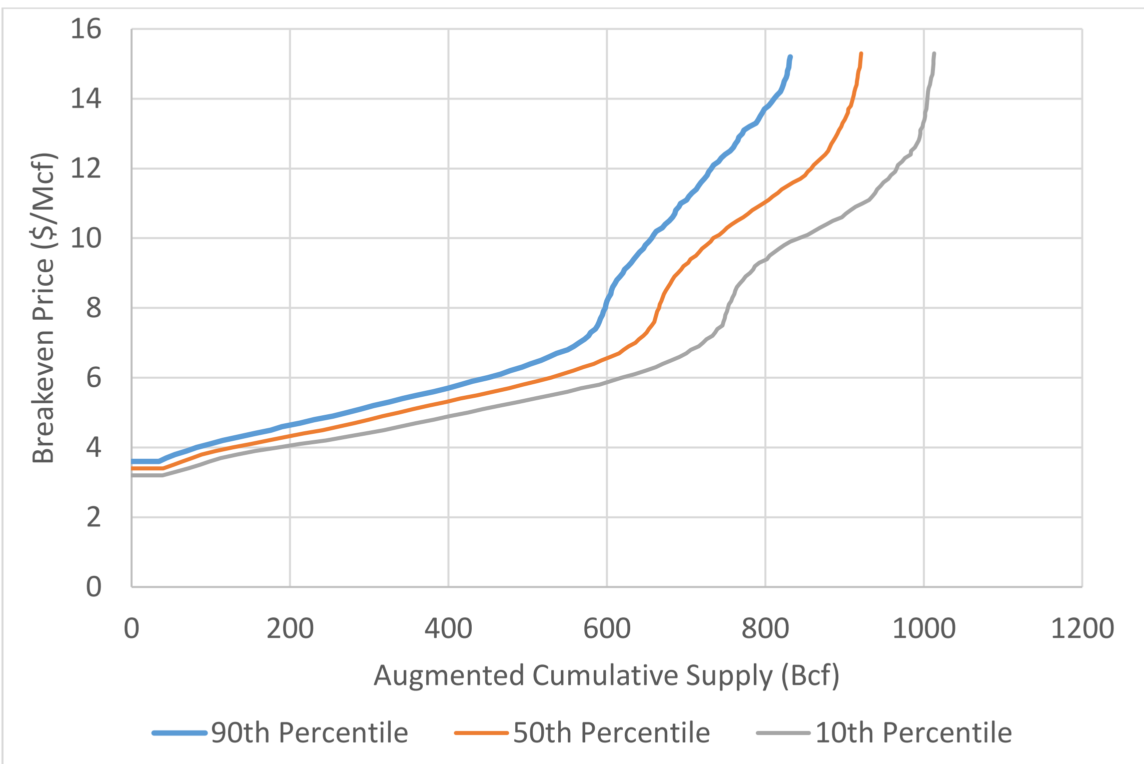

Figure A-1. Cumulative supply from augmented production sources (15% real hurdle rate)

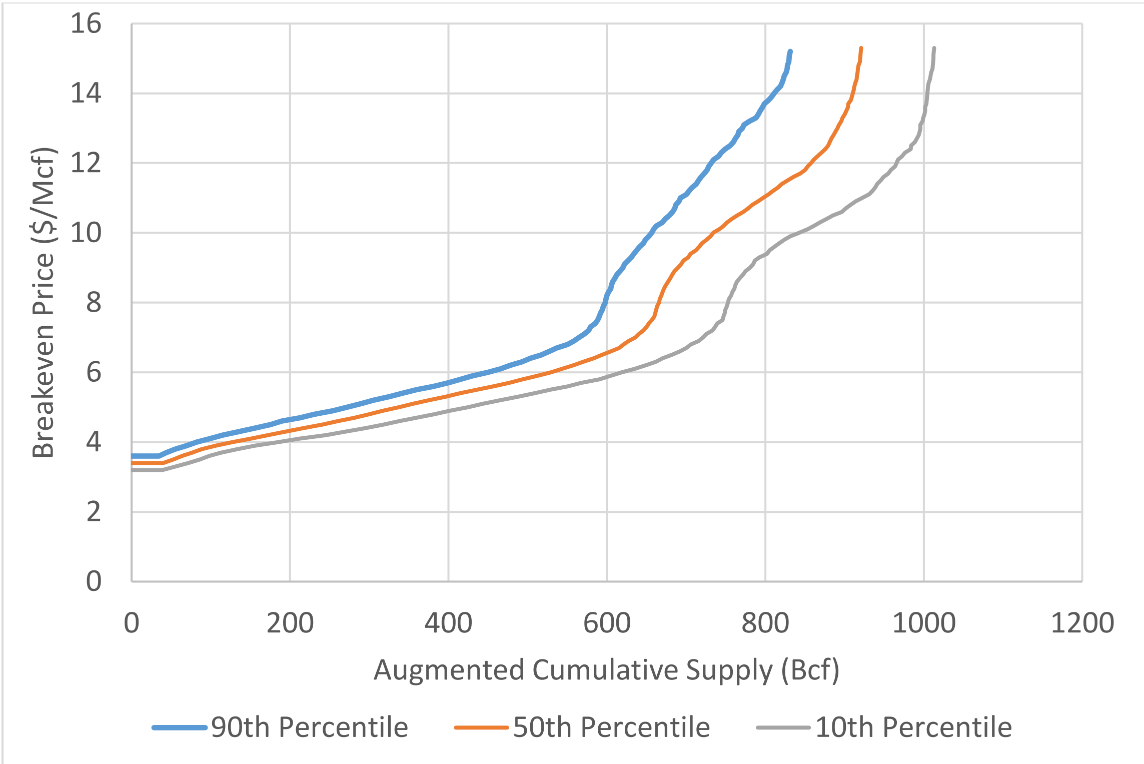

Figure A-2. Cumulative supply from augmented production sources (20% real hurdle rate)

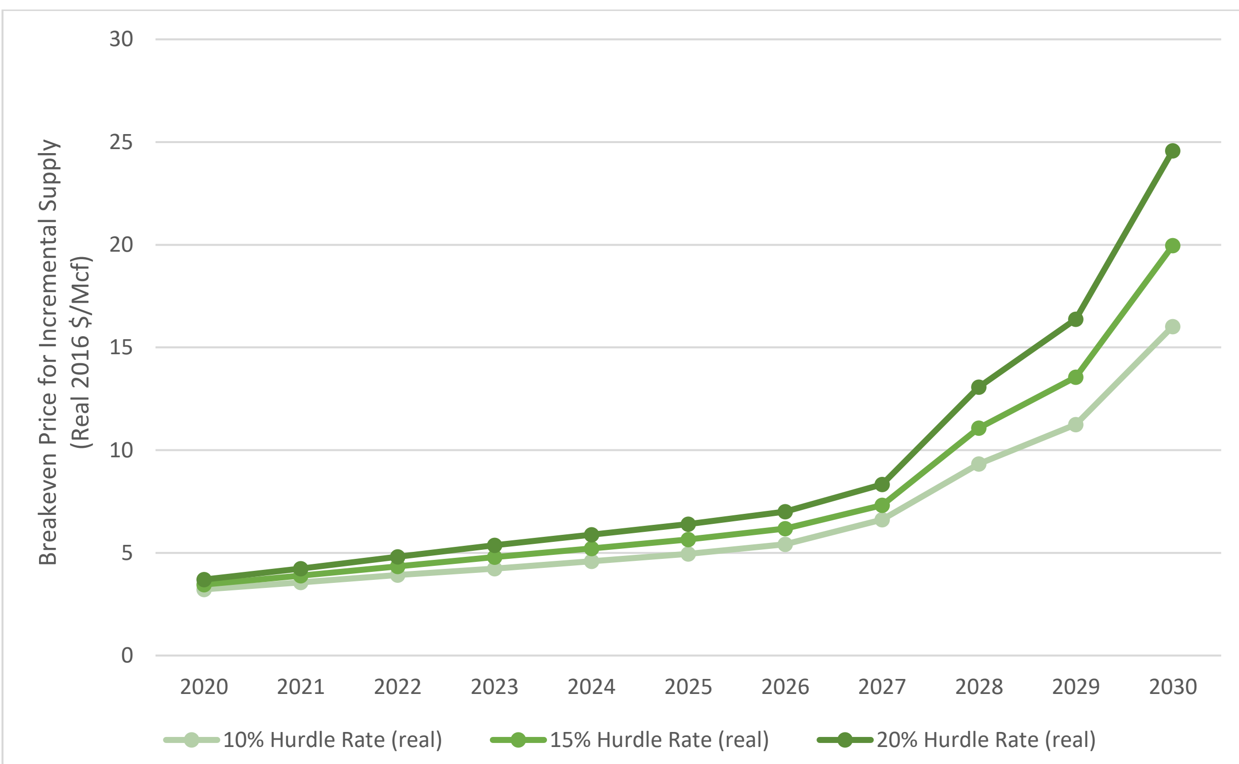

Figure A-3. Natural gas breakeven prices over time under 80 Bcf/year demand (10th percentile cases)

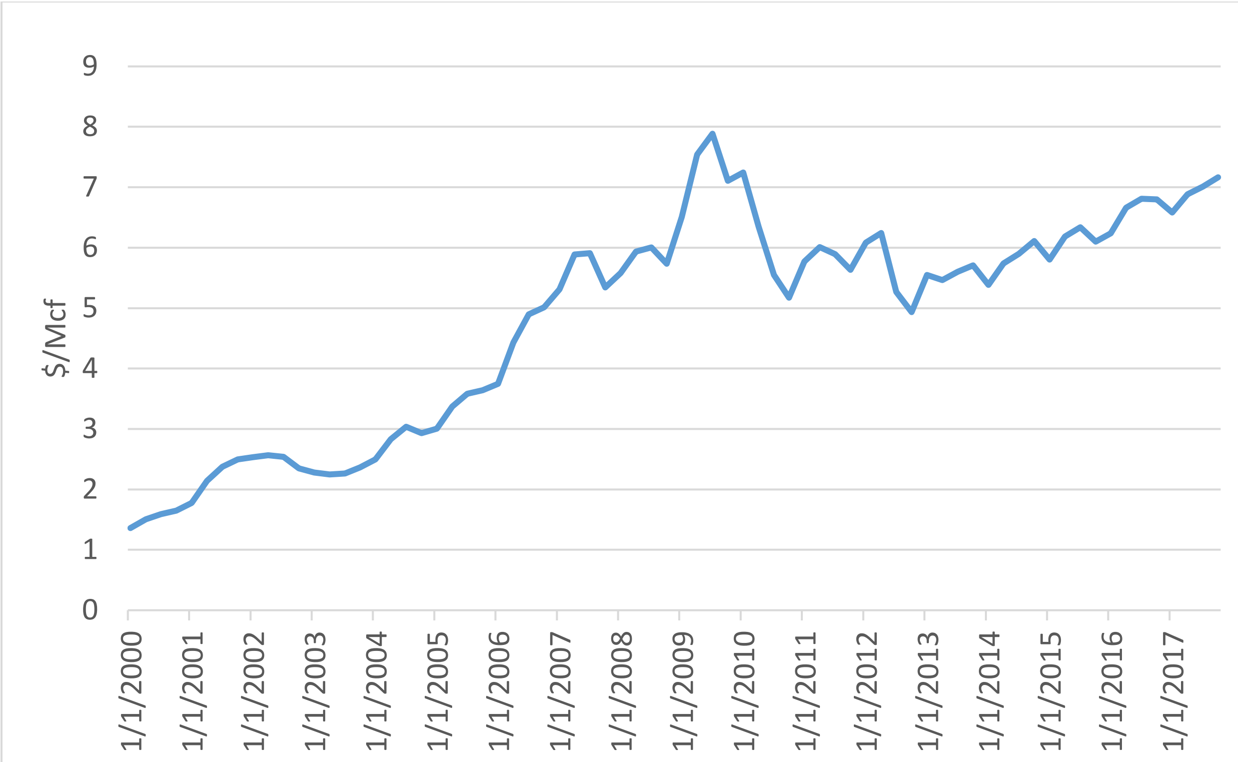

Figure A-4. Cook Inlet natural gas prevailing value ($/Mcf)

Source: DOR (2017)