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

# 2022 Cook Inlet Gas Forecast

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# Executive Summary

The Cook Inlet basin has served as the Railbelt region's exclusive source of natural gas for over six decades. As oil and gas fields in Cook Inlet continue to mature, there is an ongoing need to assess the basin's capacity to meet natural gas demand over the coming years. This study provides an updated assessment of Cook Inlet gas availability. Specifically, the Department of Natural Resources (DNR) addresses the following key questions:

- *What is the quantity of proved gas reserves in Cook Inlet?*
- *How long can Cook Inlet gas meet existing demand levels?*

This analysis builds on three previous DNR Cook Inlet gas studies (Hartz et al., 2009; Munisteri et al., 2015; Redlinger et al., 2018), while incorporating new and relevant information. Modelling of future production is from both existing wells and an applied conservative estimate to new wells being drilled in fields that remain active and continue to develop.

There are three main findings of this study:

- There are significant gas volumes potentially available through additional investment and development in currently producing fields. DNR estimates that there is 820 billion cubic feet (bcf) of proved gas reserves that is economic to develop. 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 fully satisfy the current demand level of about 70 bcf per year until around 2027, given the assumptions and simplifications of this analysis.
- Because the scope of the gas forecast in this study is limited to the proved developed and proved undeveloped categories, the sanctioning of gas projects that are currently under evaluation for their commercial viability is an important contributor in meeting the demand of gas when the economic production in this study falls below 70 bcf per year.

There are important limitations to this study. First, this analysis should not be interpreted as a forecast of the demand for Cook Inlet natural gas. The results present the economic feasibility of production from proved developed and proved undeveloped reserves 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 capacity to meet natural gas demand under present conditions and assumptions. Accordingly, the results should be considered in the context of the study's scope and in mind of its limitations.

# Introduction

Oil and gas production started in the Cook Inlet basin after the discovery of the Swanson River field in 1958. The Cook Inlet basin has produced 8,876 billion cubic feet (bcf) of gas and 1.4 billion barrels of oil as of December 31, 2021. Historically, gas cycling has been used for enhanced oil recovery purposes within the Cook Inlet basin, particularly within the Swanson River field. Hence, a net balance of produced and injected gas was considered to calculate cumulative produced gas.

There is concern over whether present natural gas production and delivery in the Cook Inlet basin can continue to meet the energy demands of south-central Alaska. The gas market in south-central Alaska is a nearly closed market with little current connection to alternative points of sale or supply.

This report is a technical and economic reserves assessment of 38 currently or historically producing Cook Inlet gas fields using publicly available production data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) and addresses the remaining gas reserves in the Cook Inlet basin.

Reservoir engineering principles and commercial analyses were used to evaluate the volumes of gas remaining within the Cook Inlet basin. The analyses represent current estimates by DNR, Division of Oil & Gas (Division) staff, not the operators. AOGCC defines reservoirs as pools, and the same nomenclature has been applied throughout this study. All 38 currently or historically producing Cook Inlet gas fields, many of which contain multiple pools, were evaluated by applying probabilistic decline curve analysis (DCA) and type curve analysis to the publicly available production data. Extrapolating production trends, these techniques were used to derive estimates of remaining reserves, which are considered equivalent to the proved reserves category.

# Scope and Application

This report evaluated 90 different oil and gas pools in the Cook Inlet Basin as defined by AOGCC, within the 38 different fields, with historical production considered through December 31, 2021. Probabilistic DCA forecasts were performed at the pool-level for currently producing gas and associated gas reservoirs beginning January 1, 2022. Due to the time it takes to forecast each of the 90 pools, there is inevitably a time lag between the cutoff date and publication. For observational purposes, this allowed the Division to compare actual production rates to the probabilistic forecast through October 31, 2022.

Solution gas associated with fields producing oil must also be considered as part of the gas reserves inventory. Field-level oil forecasts were generated to determine an economic field oil rate that directly impacts produced associated gas forecasts. The length of untruncated forecast projections were held to 20 years or less, depending on reservoir performance.

Future development assumed a steady drilling pace of 15 development wells per year for the remainder of the decade, based on both historical development wells drilled between 2009 and 2019 and confidential information received from operators for specific fields that remain active and continue to develop in the Cook Inlet basin. Years beyond 2019 were considered outliers and not factored in this drilling pace assumption due to impacts from the COVID-19 pandemic and associated market crash. The forecast does not assess or assume how many wells may be drilled after 2030.

Additional geological considerations, such as potential reserves in bypassed reservoirs, discoveries not yet on production, and nonproducing intervals in existing pools are outside the scope of this report and have not been considered. Furthermore, this report does not address prospective (undiscovered) or contingent (discovered, non-producing) resources, nor do these engineering and commercial methods quantify 2P (proved + probable) and 3P (proved + probable + possible) reserves, which would include more speculative gas volumes.

This report does not account for gas produced from gas storage reservoirs to avoid duplicative gas volumes produced for sales.

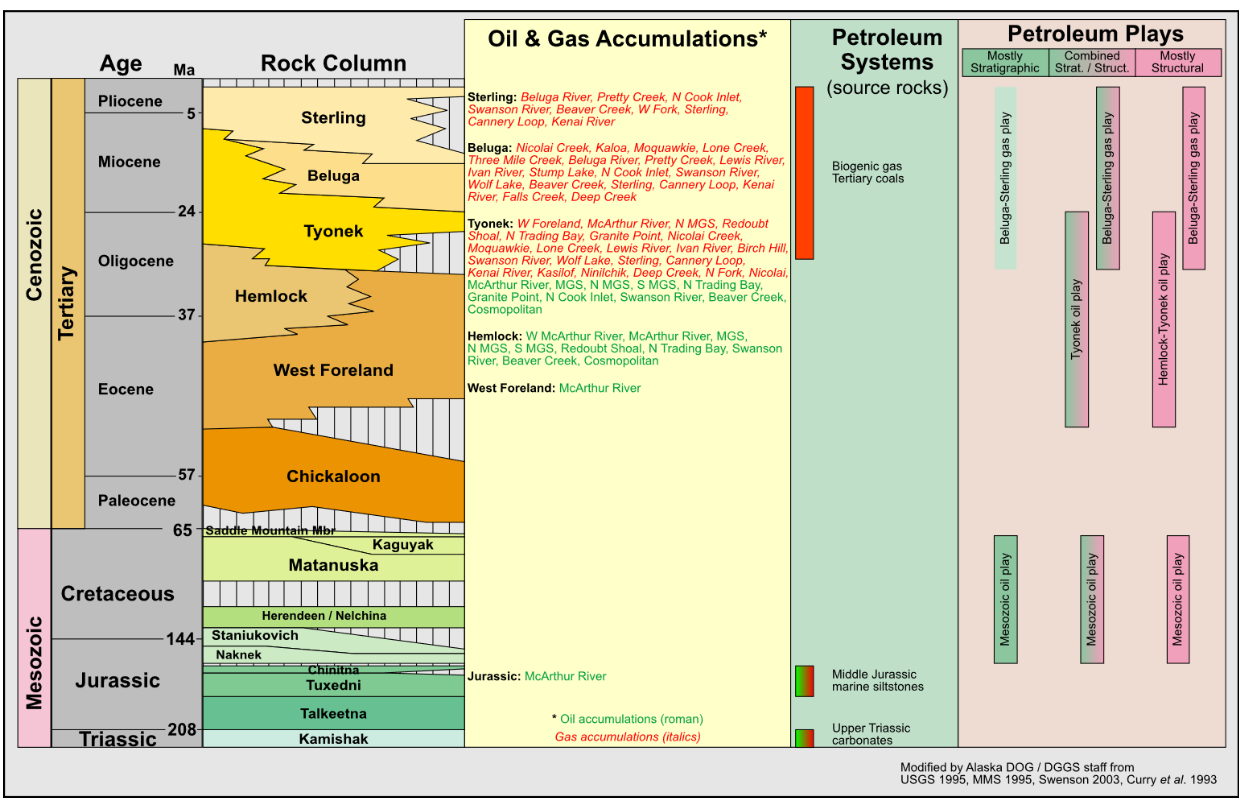
## Cook Inlet Geological Setting

The Cook Inlet basin is a northeast-southwest trending, fault-bounded forearc basin extending from the Matanuska Valley southward between the mountainous uplands of the Kenai Peninsula and the Alaska Peninsula. Numerous northeast-southwest trending anticlinal folds exist within the basin due to extensive right-lateral strike-slip and dip-slip motion along the northern and northwestern basin-bounding faults.

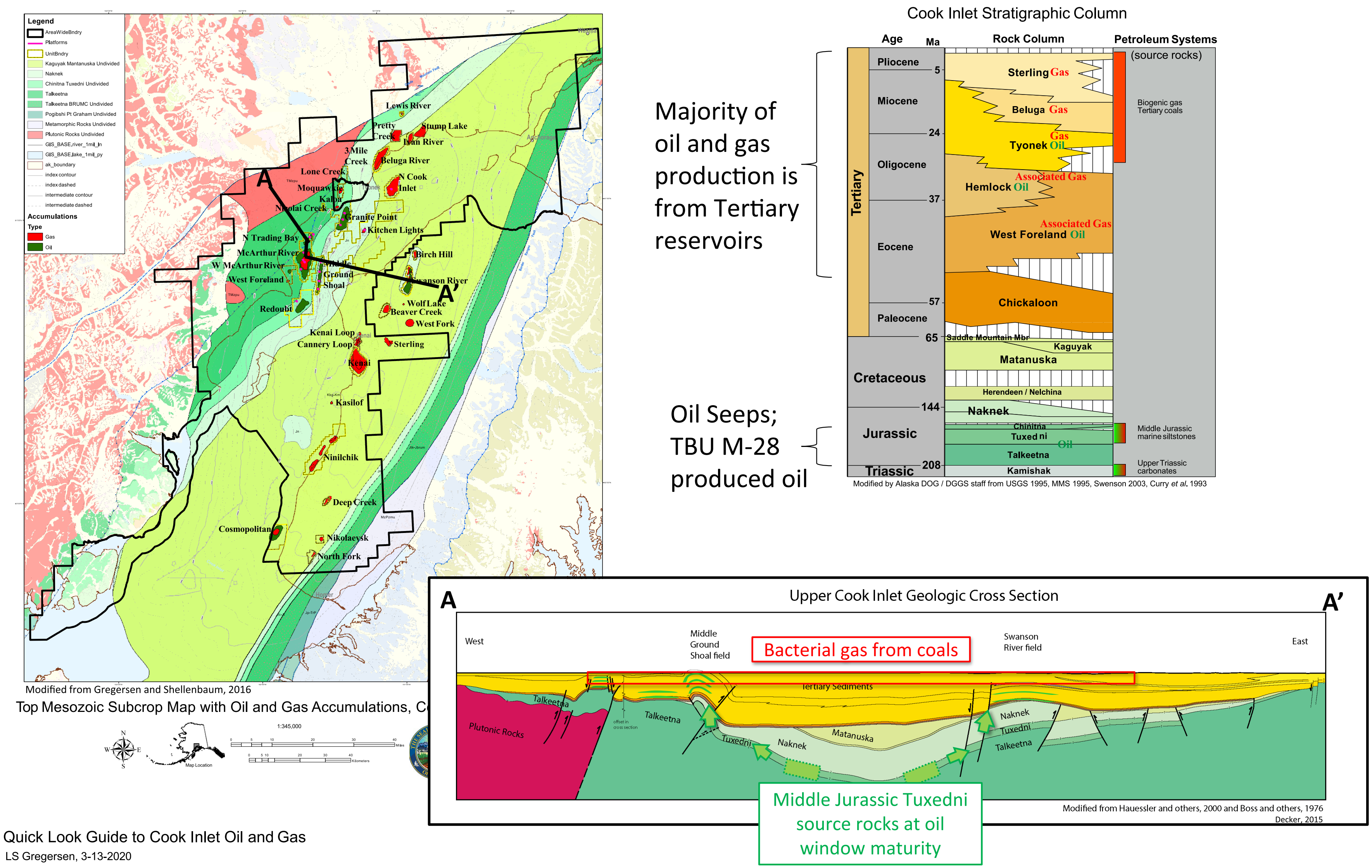
Mesozoic and Tertiary sedimentary strata make up the basin fill. Most of the producing reservoirs in Cook Inlet basin are found in the non-marine Tertiary section (Figure 1). Along the basin margins, Tertiary reservoirs consist largely of gravelly alluvial fans and sandy braided channels. Toward the basin axis, the reservoirs consist largely of fluvial channels interlayered with overbank silts, clays, and coals.

There are two distinct petroleum systems in the Cook Inlet basin: a thermogenic system, consisting of oil and associated gas derived from deep burial of Mesozoic source rocks, and a biogenic system comprising dry (non-associated) methane generated in the shallow subsurface as a byproduct of bacteria feeding on Tertiary coals (Figure 2, page 6). Reservoirs in the Sterling and Beluga formations are primarily dry gas. Reservoirs in the West Foreland and Hemlock formation are primarily oil. The Tyonek formation contains both dry gas and oil reservoirs.

**Figure 1. Cook Inlet stratigraphic column, with petroleum plays and oil & gas accumulations**



## Figure 2. Cook Inlet Sub Crop and Cross Section mapping

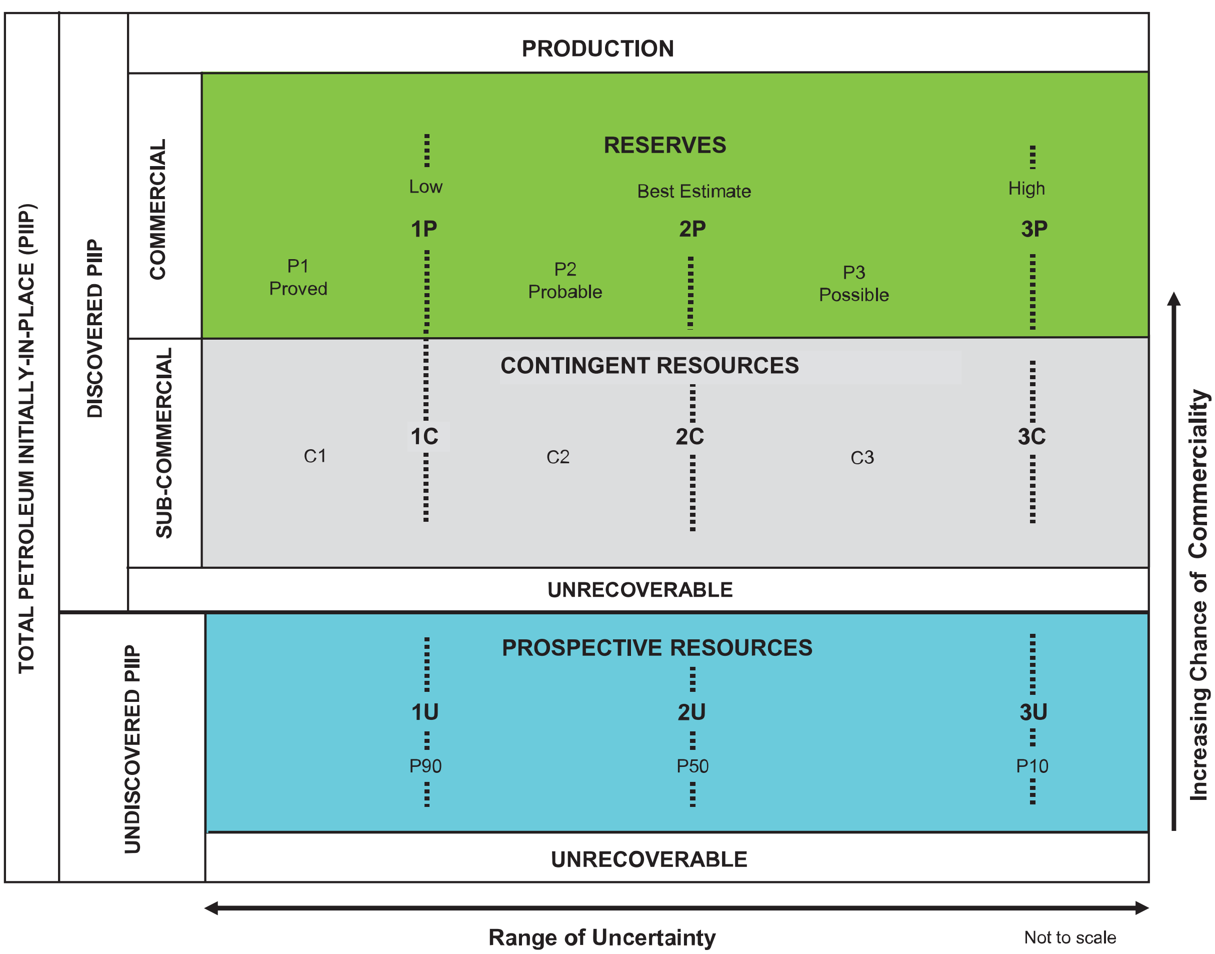


## Reserves Briefly Defined

The Petroleum Resources Management System (PRMS) is a system sponsored by various societies worldwide to categorize and classify all petroleum reserves and resources. The PRMS divides total in-place oil and gas into three major categories: undiscovered, discovered sub-commercial, and discovered commercial resources (Figure 3). Undiscovered volumes, also known as *prospective resources*, are estimated to exist in accumulations not yet found by drilling. Discovered, sub-commercial volumes are often referred to as *contingent resources*; although confirmed by drilling, resources are not yet ready for production, or have not yet been demonstrated to be commercially viable to produce. Discovered, commercial oil and gas make up the *reserves* category. Reserves are subcategorized by certainty of production into 1P (proved, or 90% certainty), 2P (proved and probable, or 50% certainty), and 3P (proved, probable, and possible, or 10% certainty).

For this report, reserves are determined by Decline Curve Analysis (DCA) and Type Curve Analysis, both of which are deemed as acceptable approaches for approximating the levels of production certainty associated with 1P reserves estimates. Reserves determined through DCA applied to currently producing pools are categorized as *proved*, or 1P, and represent future production from productive pools without any further investment as of January 1, 2022. The underlying premise of DCA is that a trend from historical production (dependent on drilling, maintenance, and remediation) will behave as such into the future. The results of DCA represent a snapshot of the past performance characteristics of a given reservoir and the resultant trend forecasting future recovery.

**Figure 3. 2018 PRMS resource classifications**



# Technical Methodology

*Decline Curve Analysis and Probabilistic Forecasting*

This is an industry standard engineering practice, extrapolating recent trends of production decline into the future. Using this method, future production from a pool is assumed to follow a trend similar to a given segment of production in the past. Probabilistic forecasts were generated for currently producing pools to show a range of possible production into the future by using statistical analysis in addition to traditional DCA to derive a probabilistic range of outcomes, including High (P10), Mid (P50), Low (P90), and calculated Mean Cases. These forecasts are weighted toward recent production history. Engineering judgement is applied to honor recent field development and reservoir constraints. Ultimately, all DCA-based forecasted reserves estimates are dependent on the economic limit applications used to truncate future production and the forecasting assumptions used.

*Type Curve Analysis*

Type Curve Analysis is an industry standard engineering practice accounting for both geological parameters and reservoir conditions and is grounded in decline curve and statistical analysis using historical production data. Type curves are generated from a population of representative wells in producing pools to characterize the behavior of future wells drilled in respective pools.

# Economic Limitations

In addition to the estimated technically recoverable gas to be produced from the Cook Inlet basin, this report provides an estimate of the amount of such gas that would be economic to produce based on a number of assumptions and fixed considerations. In other words, the Cook Inlet gas estimate generated by the decline curve and type curve analyses provides an outlook of potential gas production from the proved developed and proved undeveloped categories. However, it is likely that not all this potential gas production would be realized since upstream companies will not operate their fields at a sustained loss. Therefore, this report estimates economically feasible production of Cook Inlet gas by imposing a limit to the technically recoverable gas for each field[1]. This economic limit manifests when the marginal revenues associated with production of oil and gas from a field in a month are no longer enough to cover its corresponding marginal costs. In such event, the otherwise technically recoverable gas becomes economically infeasible and no longer available to buyers. If a producer is faced with this event or expects it to occur, then the option to shut down the oil and gas field will more likely be chosen, thus rendering any forecast of gas production beyond such time from a field irrelevant.

The development of the economic limit imposed to the technically recoverable gas considers the revenues from the commercialization of oil and gas production from each field, includes assumptions for costs associated with the production of oil and gas, applies the corresponding royalty take by the different royalty owners (namely, the State of Alaska, the federal government, and private

[1] While the gas forecast using DCA and type curve analyses is carried out at the pool level, the economic limit test in this report is done at the field level. This is a simplification implemented due to the lack of detailed cost information. A more realistic design of the economic limit test would allow for the presence of different cost centers (e.g., at the well, pool, pad, platform, and field) and their impacts on the economic production for each oil and gas pool.

organizations[2]) where appropriate, and calculates the applicable taxes such as the oil and gas production and property taxes[3].

In contrast with the case of oil, where market participants are price takers, the price of Cook Inlet gas is not the result of a highly liquid, transparent, and actively traded commodity market. Instead, the Cook Inlet gas market can be characterized as separate and isolated from the evolution of other more liquid and heavily traded gas markets such as Henry Hub in the Lower 48. Therefore, the price of Cook Inlet gas is determined by the market power that producers (as sellers) and buyers (e.g., local utilities, other oil and gas producers in Cook Inlet, or local refineries) have when negotiating gas selling agreements.

Figure 4 (page 10) shows that a significant share of the demand for Cook Inlet gas (see the residential and electric segments) stems from the needs of the local utilities (*e.g.,* Enstar Natural Gas Company, Chugach Electric Association Inc., etc.), whose prices for services such as electricity or heating fuel to consumers are subject to the oversight of the Regulatory Commission of Alaska. Therefore, the calculation of revenues associated with the commercialization of gas production in this study uses an approximation of the schedule of gas prices present in the contracts between the local utilities and the gas producers for the sale of gas from every gas-producing pool for sale to the market. This schedule of gas prices is an input of the review process by the Regulatory Commission of Alaska and the information is publicly available. Although these gas contracts differ in the amounts of gas committed, variability, deliverability, optionality, and duration, this study simplifies the treatment of these contracts as if they offered similar non-price terms, thereby only using the price information contained in them.

The focus of this study is on the forecast of gas that would be economically feasible. Considering this, the selection of a particular oil price profile does not create a material impact on the economic feasibility of the aggregate forecast of Cook Inlet gas because, typically, associated gas encountered in oil fields does not represent a significant portion of the potential for gas production in the Cook Inlet basin.

It is worth noting that not all the gas produced will be available to the market. This study segregates technically recoverable gas production into two categories: the amount of gas available for sale to buyers, and the remaining amount of gas that would be dedicated to in-field operations (such as fuel needs or for enhanced oil recovery)[4] . Therefore, there is a portion of produced gas that neither generates direct revenue to the producer nor creates any royalty payment obligation since it is not being sold.

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[2] There are producing oil and gas fields in the Cook Inlet basin where the royalty owner is the Bureau of Land Management, representing the U.S. federal government, such as the Swanson River field. Other fields are also partially owned by private individuals, private organizations such as the Cook Inlet Region Inc. or Hilcorp Alaska, LLC, the State of Alaska, and the federal government such as in the Ninilchik field.

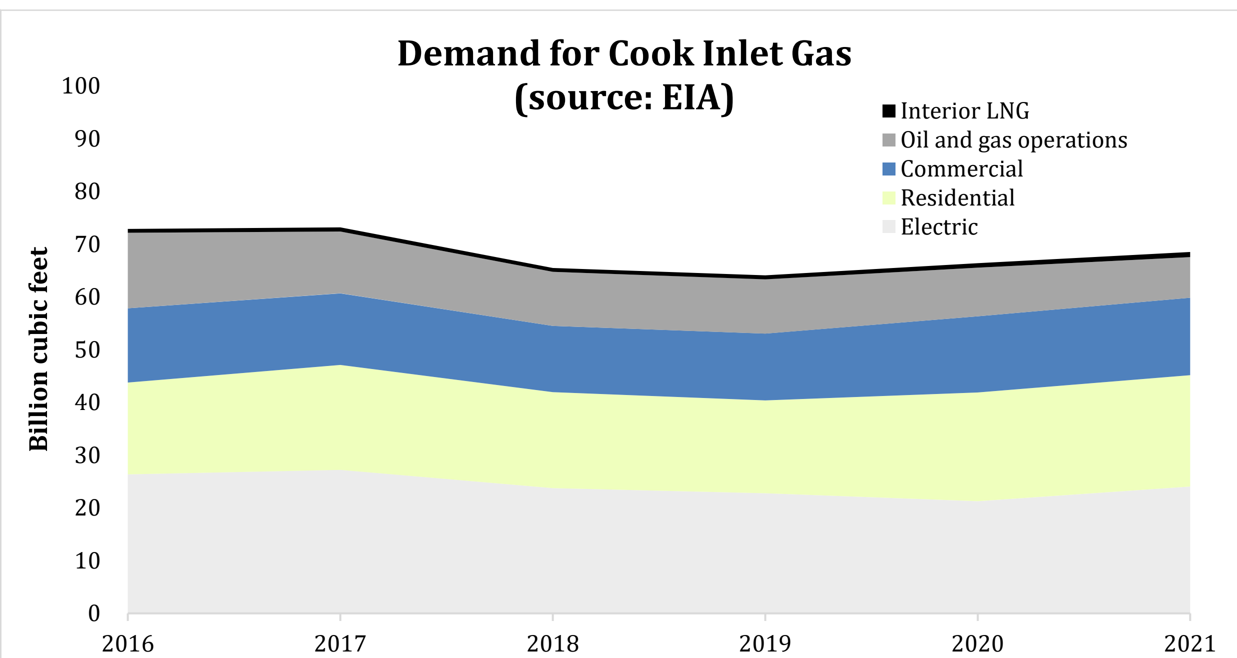
[3] This study does not consider the state corporate income tax, as defined under AS 43.20, in the construction of the economic limit because the focus of the economic limit is on the oil and gas field whereas this tax is assessed at the taxpayer level. Moreover, if the producer of an oil and gas field is a pass-through entity (an S corporation), then such entity will not be subject to state or federal corporate income tax, but rather its owners.

[4] There is a small amount of gas that could be unavoidably lost, flared, or vented.

This study uses assumed values for the cost of production of oil and gas for the various fields in the Cook Inlet basin which approximate information that is publicly available. Because of the public nature of this report, the protections provided by Alaska Statute (AS) 38.05.035(a)(8), which allows producers to request confidentiality for sensitive business information provided to DNR, and the unavailability to DNR of detailed actual cost information for every oil and gas field, this study follows a one-size-fits-all approach with respect to the cost assumptions. However, this economic analysis allows for differences in the production costs as a function of the proximity of the oil and gas fields to infrastructure such as roads, pipelines, and pads. For example, the cost of production for oil and gas for offshore fields is relatively higher than onshore fields. Likewise, fields located on the Western side of the Cook Inlet basin tend to experience higher costs than those on the Eastern side. As can be expected, varying these cost assumptions that are applied generally to the oil and gas fields in the Cook Inlet basin would change the results of the estimate of economically feasible gas production. For example, a higher cost profile could accelerate the time when some oil and gas fields reach the end of their economic lives. In this way, cost assumptions in this study highlight the effect of the economic limit and the fact that—once considering the revenue profile, the costs of production, royalties, and taxes—the forecast for technically recoverable production of gas in the Cook Inlet basin is constrained.

Figure 4 shows the demand for Cook Inlet gas by end use sector on an annual basis for the period 2016-2021, averaging approximately 70 bcf per year. The scope of this study does not include the modeling of the factors driving the demand for Cook Inlet gas in the future. The focus is constrained to the supply side. However, in considering the outlook for economically feasible gas production from Cook Inlet, this study assumes that the observed demand profile of 70 bcf per year will remain largely unchanged. In other words, this means that, for the forecast period, consumers will not find substitutes for Cook Inlet gas or that they will not reduce their energy consumption. Although it is possible for buyers to decide to replace the need for Cook Inlet gas with other sources of energy, it is also worth noting that there are latent contributors to the outlook for Cook Inlet gas demand. Projects such as Donlin Gold could increase the demand for Cook Inlet natural gas by approximately 12 bcf per year resulting from the need to provide power to its proposed facilities and mining operations. A higher demand profile for Cook Inlet

**Figure 4. Demand for Cook Inlet gas**



gas could increase the appeal or incentive for further exploration in the basin of contingent or prospective gas resources. The Donlin Gold project includes building a 315-mile natural gas pipeline (located in the vicinity of the Beluga Gas Field)[5]. Although the project is not yet at the final investment decision stage, its sponsors state that the project is approaching a feasibility study decision while continuing with planned drilling programs[6].

Other sources of additional demand for Cook Inlet gas cited in Redlinger, M., Burdick, J., & Gregersen, L. (2018) entail a more uncertain outlook for increased demand of Cook Inlet gas. For instance, the potential restart of the Agrium Kenai fertilizer plant is currently conceptualized under the Alaska Hydrogen Hub project sponsored by the Alaska Gasline Development Corporation with the support of Agrium U.S. among other entities[7]. Under this proposal, the Kenai fertilizer plant would use natural gas feedstock from the Alaska LNG Project to produce conventional liquid ammonia. Although it may be possible for this fertilizer plant to also demand Cook Inlet gas, this is still uncertain. Another potential source of incremental demand for Cook Inlet gas cited in Redlinger, M., Burdick, J., & Gregersen, L. (2018) is the export of LNG from the Kenai LNG facility. The current owner of the facility, Marathon Petroleum Corporation, via its subsidiary, Trans-Foreland Pipeline Co, received approval by the U.S. Federal Energy Regulatory Commission for an extension of the permit to convert the LNG terminal from an export to an import facility until December 2025[8]. Although Marathon Petroleum Corporation has not yet made a final investment decision to build the project, it claims that the next step is the obtention of commercial agreements for the supply of LNG. This significantly reduces the likelihood of a potential need for Cook Inlet gas dedicated to the export of LNG. Lastly, the other potential source for additional demand for Cook Inlet gas is related to the consumption from the Interior Gas Utility. Figure 4 (page 10) shows the demand for Cook Inlet gas coming from needs of the Interior Gas Utility whereby natural gas is transformed into LNG and transported to the Interior for regasification and distribution to customers. Although the Interior Gas Utility has an existing contract with Hilcorp Alaska, LLC for the supply of natural gas from Cook Inlet until 2032, the utility recently announced a 20-year contractual agreement with Hilcorp North Slope, LLC and Harvest Midstream, LLC for the supply of natural gas from the North Slope and conversion to LNG[9]. This may reduce the likelihood of future increased demand for Cook Inlet gas by the utility.

Although Figure 4 (page 10) shows that the annual consumption remained relatively stable in this period, it is worth noting that the consumption of Cook Inlet gas is seasonal and varies throughout the year, which highlights the important role of gas storage capacity in the Cook Inlet basin. The cost to store such gas is another element in the cost structure that producers of Cook Inlet gas may face. The scope of this study does not include the effects of any lack of available capacity in gas storage fields or the impacts of the cost to store and withdraw gas.

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[5] See Hanson, Kirk; Michael Woloschuk; and Henry Kim (2021). "*NI 43-101 Technical Report on the Donlin Gold Project, Alaska, USA.*" https://www.novagold.com/_resources/projects/Technical-Report-Donlin-Gold-2021.pdf

[6] See https://www.barrick.com/English/news/news-details/2022/donlin-gold-reports-excellent-initial-2022-drill-program-results/default.aspx.

[7] See https://agdc.us/wp-content/uploads/2022/11/Hydrogen-Hub-Application-Announcement-Final.pdf.

[8] See https://www.reuters.com/business/energy/marathon-gets-more-time-build-lng-import-project-alaska-2022-08-16/.

[9] 1/17/2023 IGU Special Board Meeting Packet at https://www.interiorgas.com/board-documents/.

Besides production costs, this study includes royalties producers must pay as another component in the economic limit imposed to the technically recoverable gas. In doing so, this study uses the corresponding royalty rates for each producing field in the Cook Inlet basin as well as any applicable decision by the DNR allowing for the reduction of the royalty rates pursuant to AS 38.05.180(f)(4)[10] and AS 38.05.180(f)(6)[11].

This study also considers another type of royalty interest: overriding royalty interests. Much like the case of royalty, they represent another claim on the gross revenues from the production of oil and gas in the Cook Inlet fields before the deduction of operating and capital costs. Typically, these overriding royalty interests result from transfers of working interest ownership in the oil and gas leases or farmout agreements. In some cases, the burden from these overriding royalty interests can be as high as 12.5% which, in combination with the royalty share, can be a significant burden to the economic viability of an oil and gas field.

Production of oil and gas in Alaska, even where subsurface rights are not owned by the State of Alaska, is subject to oil and gas production tax under AS 43.55. Similarly, tangible assets associated with oil and gas production in Alaska are subject to property tax under AS 43.56. Thus, in calculating the economic limit of technically recoverable gas production, this study includes an approximation of production tax and property tax obligations stemming from operating oil and gas fields in the Cook Inlet basin.

The result of imposing the economic limitation to the technically recoverable gas production assumes that such outlook for the supply of gas will be fully matched by the market demand at the prices used by the study. In other words, this forecast does not account for the impacts on future prices of Cook Inlet gas resulting from possible substitution with alternative energy sources that could become available at better commercial terms and thus affect the market demand for Cook Inlet gas throughout the forecast period. Lastly, this study does not account for the effects that the economic limitation at the field level could have on the economic viability of other fields or the Cook Inlet basin. For example, assume that there are two gas-producing fields that connect to a gas pipeline to transport the gas and deliver it to a buyer. If one of these two fields reaches the end of its economic life, then the throughput in the gas pipeline will be lower. This lower throughput will generate, holding other factors constant, a higher transportation cost on a per-unit basis, which will then translate into a higher cost for the surviving gas-producing field, thus potentially accelerating the end of its economic life. Another example of the basin-wide economic effect that is not captured in this study is the impact that some fields reaching the end of their economic lives could have on the service industry. A fewer number of surviving gas-producing fields could lead to the downsizing of the service industry in terms of providers or the availability of rigs.

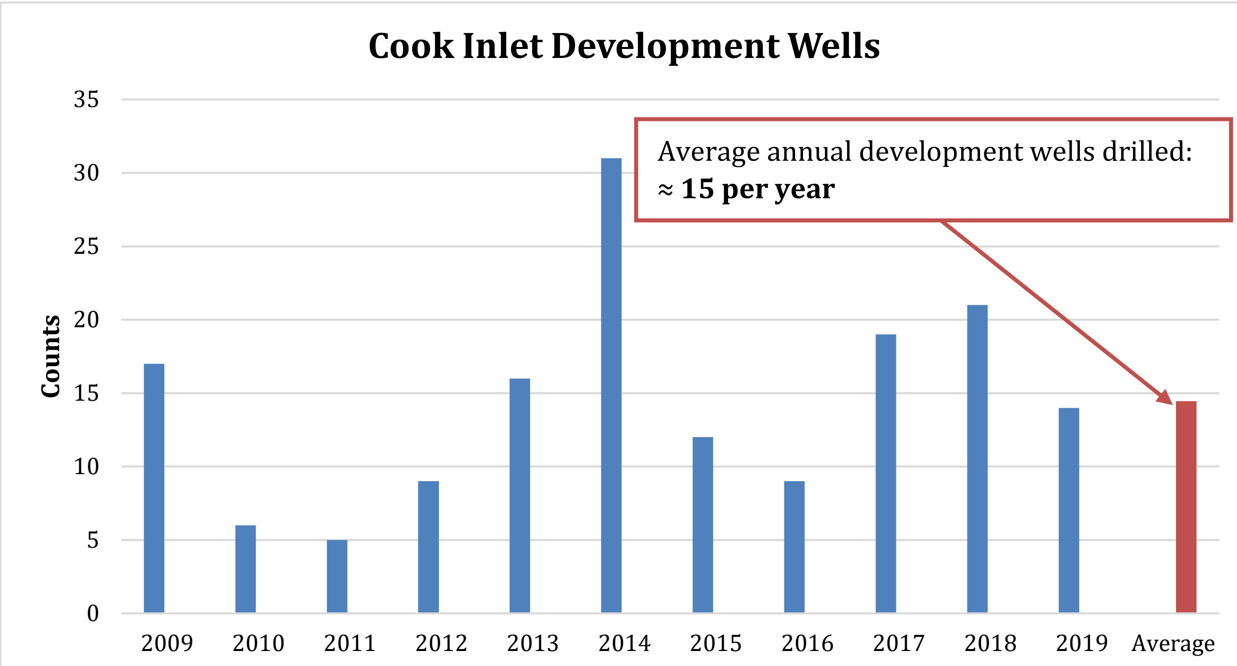
## Forecast

The Division developed a probabilistic forecast methodology from currently producing pools, which applied a modified bootstrapping technique to produce a P10, P50, and P90 rate profile for each pool. The P50 profile represents the median production forecast of the pool; implying there is 50-50 chance of actual production being above or below this forecast. There is a 10% chance that the actual production will exceed the P10 profile and there is a 90% chance that the actual production will be above the P90

[10] This corresponds to the reduction of the royalty rates for a period of ten years on leases in the Cook Inlet basin when there is a well discovering a previously undiscovered oil or gas pool.

[11] This represents a mechanism determining the reduction of royalty rates for oil production from certain platforms when such production is lower than a given threshold.

**Figure 5. Historical development wells drilled in the Cook Inlet basin between 2009 and 2019 with an average of 15 development wells drilled per year**




profile. When applying this technique, there is an 80% chance that the actual production profile of every pool will occur between the P10 and P90 profile. The application of production ranges to currently producing pools is meant to apply risk to the production forecast. The P90-P50-P10 production profiles show the possible range of future production and is derived from different trends of historical production data.

Type curves were equally applied to all relevant future wells drilled for fields that are active and have plans for continued development. Collectively, these future wells create an assumed drilling pace of 15 development wells per year into the future based on historical development wells drilled between 2009 and 2019 and confidential information received from operators (Figure 5).

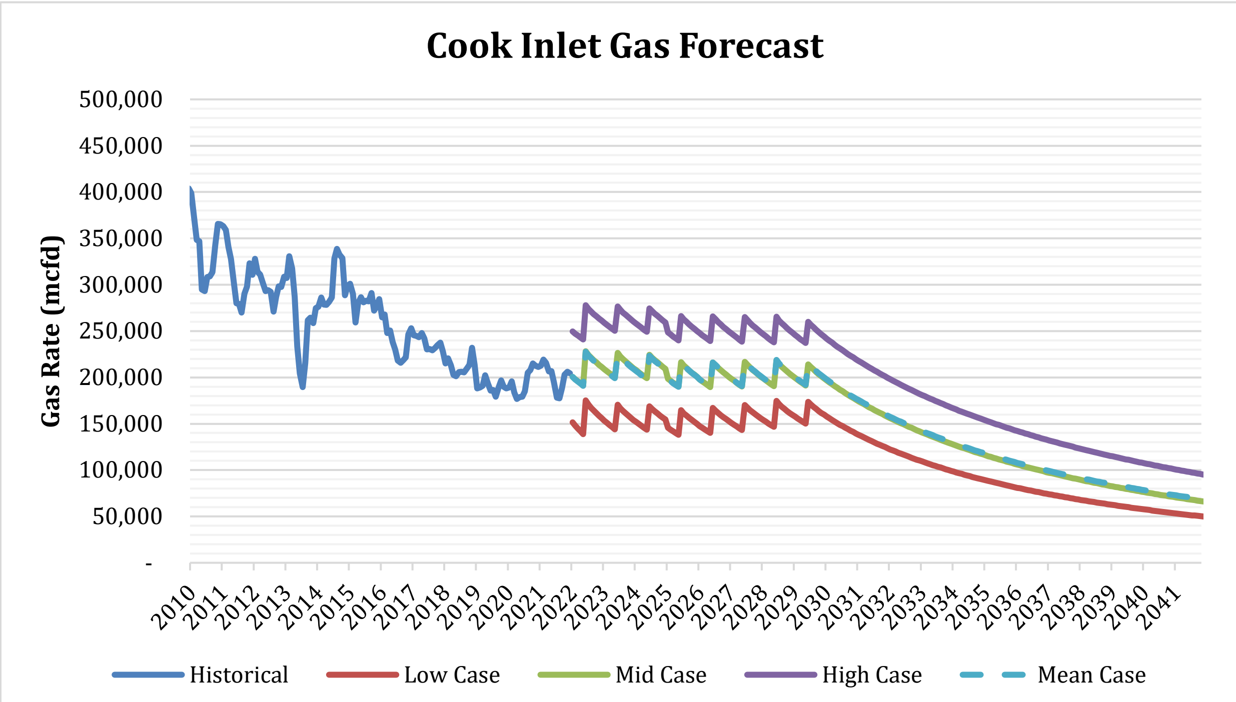
DCA pool forecasts and type curve profiles are combined and aggregated to produce a basin-wide forecast. This is then subjected to economic modeling to derive economic limits using revenue, fiscal, and cost factors to estimate remaining reserves.

The probabilistic range of total remaining gas volumes in Cook Inlet with no economics factored (Untruncated) is 1,404 bcf (High Case), 1,101 bcf (Mid Case), 843 bcf (Low Case), and 1,109 bcf (calculated Mean Case[12]), including associated gas from oil production (see Figure 6, page 14). Forecasted associated gas accounts for 1–3% of total gas being forecasted between the Low and High Cases, respectively.

[12] In this report, the Mean Case is a weighted average of the Low, Mid, and High cases. Specifically, this is the result of $Mean\ Case = \frac{(Low\ Case + 4 \times Mid\ Case + High\ Case)}{6}$.

Figure 6 shows the impact of the future wells to be drilled in the oncoming years. This is reflected in the saw-toothed pattern, which corresponds to the ongoing development drilling in the initial period of the forecast.

**Figure 6. Untruncated High-Mid-Low-Mean Streams in thousands of cubic feet per day (mcfd)**

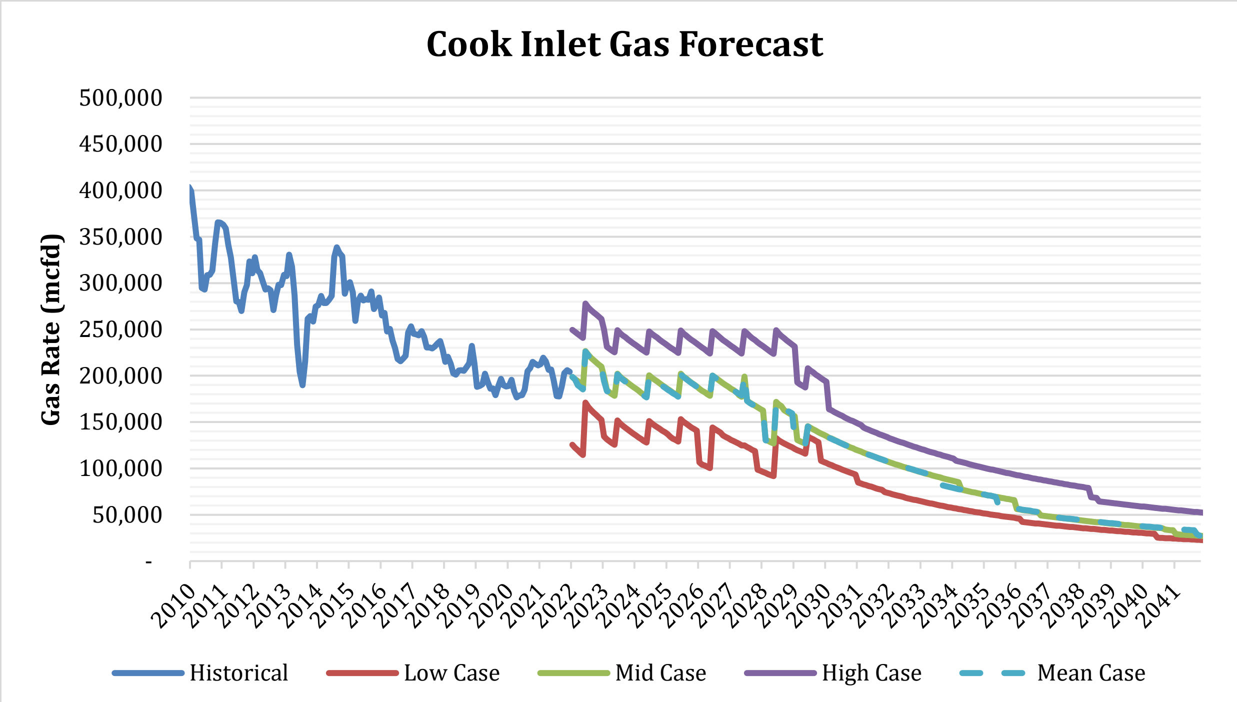



| High Case (P1) | | Mid Case (P1) | | Low Case (P1) | | Mean Case (P1) | |
|---|---|---|---|---|---|---|---|
| Total Gas Reserves (bcf) | 1,404.0 | Total Gas Reserves (bcf) | 1,101.4 | Total Gas Reserves (bcf) | 843.2 | Total Gas Reserves (bcf) | 1,108.8 |
| Gas (bcf) | 1,361.7 | Gas (bcf) | 1,079.3 | Gas (bcf) | 832.4 | Gas (bcf) | 1,085.2 |
| Associated Gas (bcf) | 42.3 | Associated Gas (bcf) | 22.1 | Associated Gas (bcf) | 10.8 | Associated Gas (bcf) | 23.6 |

The probabilistic range of total remaining gas volumes at Cook Inlet with economics factored (Truncated) is 1,109 bcf (High Case), 824 bcf (Mid Case), 603 bcf (Low Case), and 820 bcf (calculated Mean Case), including associated gas from oil production (see Figure 7, page 15). Forecasted associated gas accounts for 1–4% of total gas being forecasted between the Low and High Cases, respectively. The next graph (Figure 7, page 15) shows the impact of the economic limit test. Contrary to the case of the previous graph (Figure 6), not every field would continue producing until the last year of the forecast period. Specifically, some fields making up the Cook Inlet basin aggregate gas forecast would experience negative cash flows, which will cause the operators to shut down these fields and thus cease the production of gas to the market.

Figure 8 (page 15) shows a focused comparison of the probabilistic forecast versus actual production through October 31, 2022.

**Figure 7. Truncated High-Mid-Low-Mean Streams in thousands of cubic feet per day (mcfd)**




| High Case (P1) | | Mid Case (P1) | | Low Case (P1) | | Mean Case (P1) | |
|---|---|---|---|---|---|---|---|
| Total Gas Reserves (bcf) | 1,108.9 | Total Gas Reserves (bcf) | 823.9 | Total Gas Reserves (bcf) | 602.5 | Total Gas Reserves (bcf) | 820.2 |
| Gas (bcf) | 1,066.6 | Gas (bcf) | 807.9 | Gas (bcf) | 597.2 | Gas (bcf) | 803.2 |
| Associated Gas (bcf) | 42.3 | Associated Gas (bcf) | 16.0 | Associated Gas (bcf) | 5.3 | Associated Gas (bcf) | 17.0 |

**Figure 8. Actual production through October 31, 2022 (in thousands of cubic feet per day (mcfd)), overlayed and compared with the probabilistic forecast beginning 2022.**

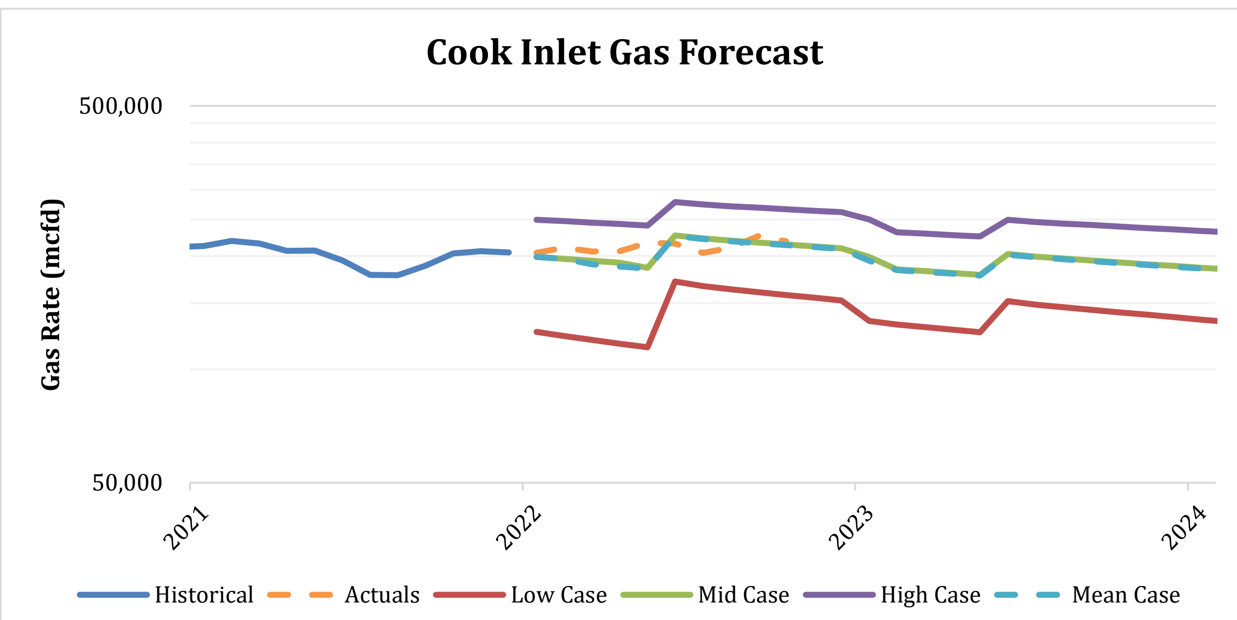
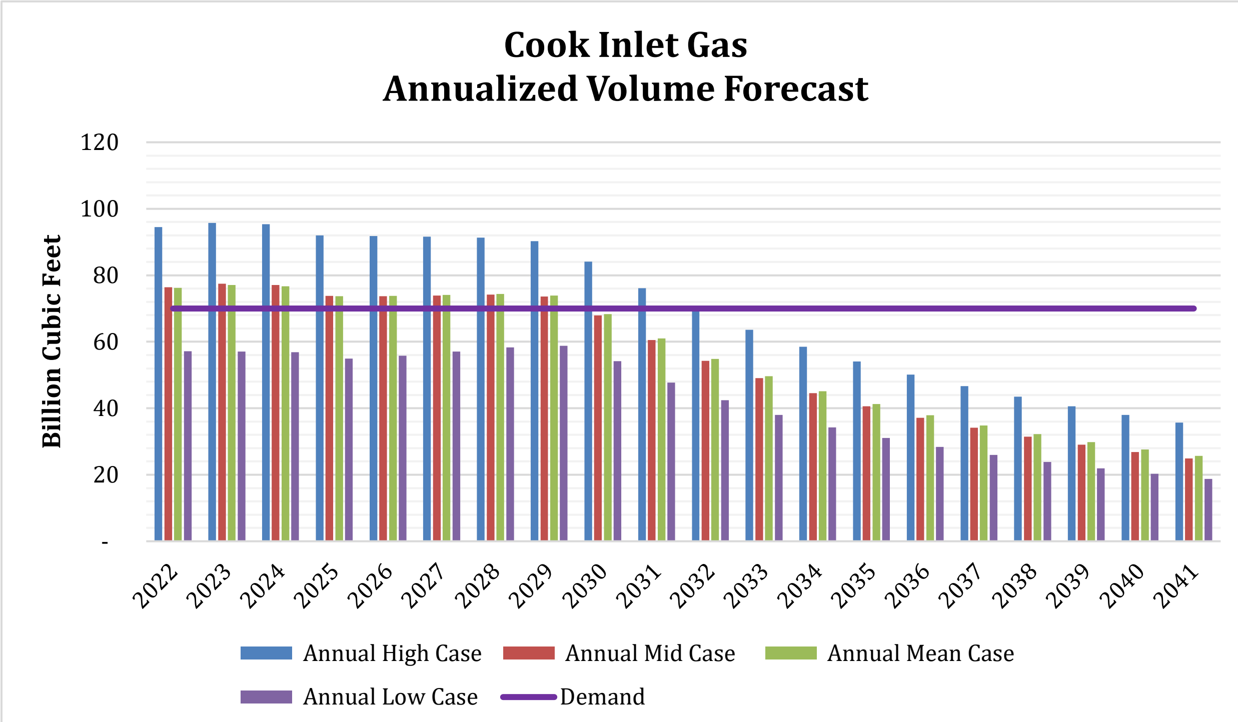


**Figure 9. Annualized Gas Volume with demand in billion cubic feet per year (untruncated)**




Figures 9 through 11 show alternative displays of the forecast in the form of bar charts. Figure 9 is an annualized gas volume forecast, while Figure 10 includes economic truncations factored for the Low, Mid, calculated Mean, and High cases.

**Figure 10. Annualized Gas Volume with demand in billion cubic feet per year (truncated)**

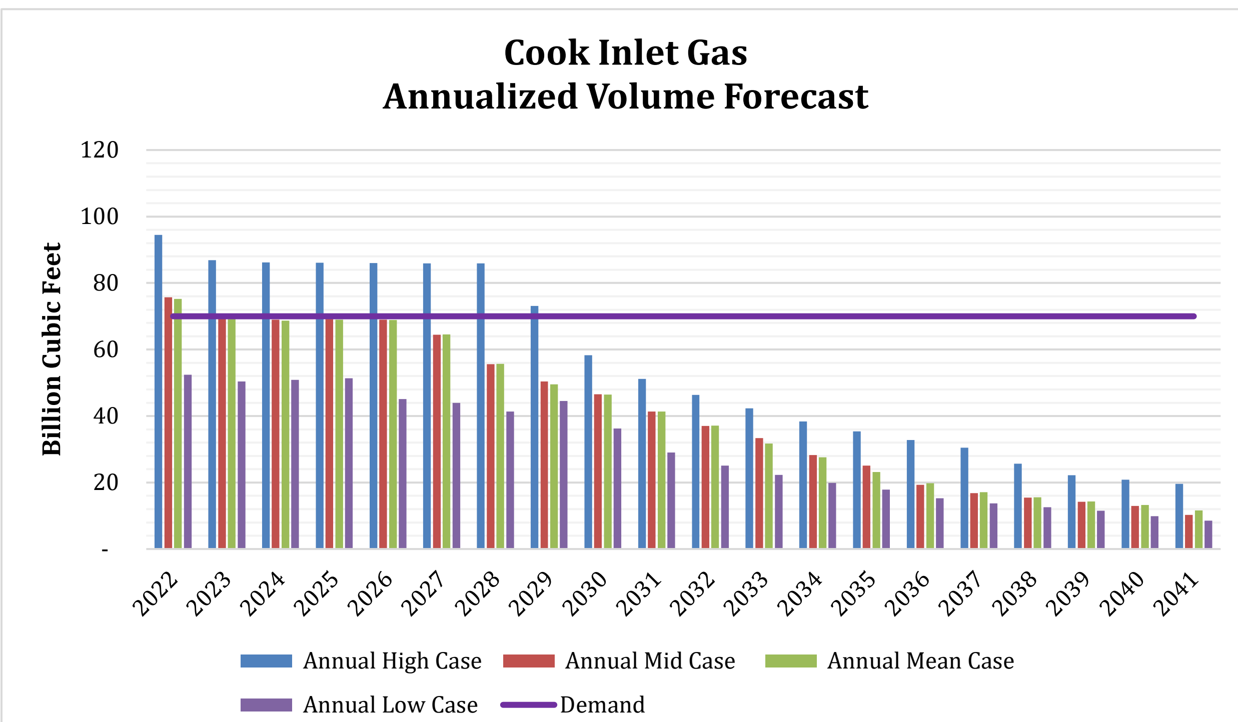
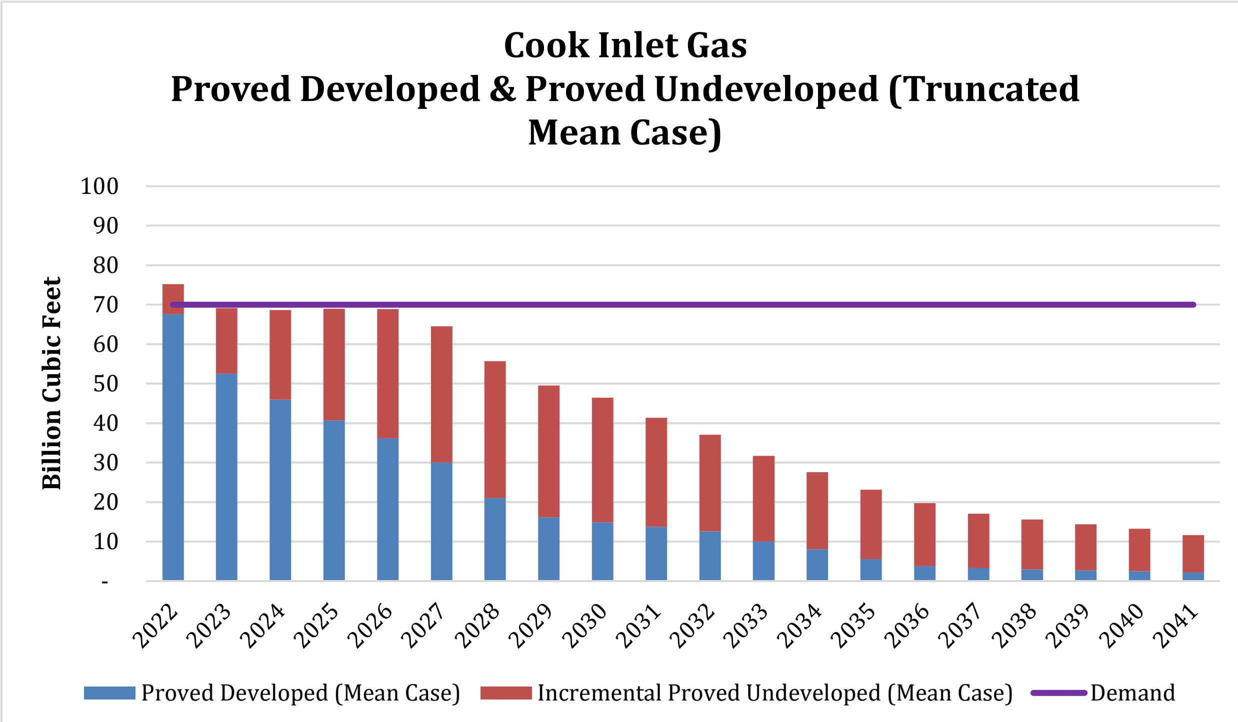


**Figure 11. Proved developed & undeveloped Cook Inlet gas in billion cubic feet per year**




Figures 9 through 10 (page 17) also show the assumed steady demand profile for Cook Inlet gas of 70 bcf per year. Figure 11 (page 17) is an annualized gas volume forecast of the mean case with economic truncations factored and a decomposition of the proved developed and incremental proved undeveloped tranches. The latter represents the contribution of gas production from the assumed schedule of 15 development wells per year. These figures suggest that the Cook Inlet gas forecast, after the use of economic limitations, has the potential to fully meet the assumed profile of demand for Cook Inlet gas until 2026–2027.

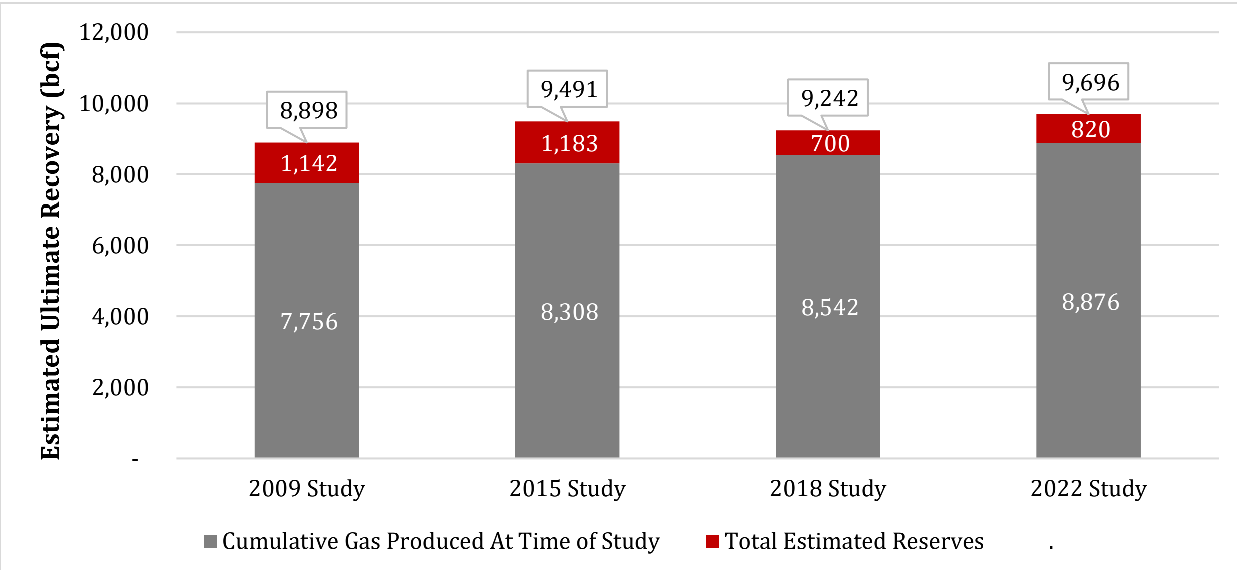
Admittedly, the use of different assumptions for costs and for the technically recoverable gas from the oil and gas fields in Cook Inlet would generate a slightly different forecast for the economically feasible gas expected to be produced. Specifically, the timing by which some fields would reach the end of their economic lives would change with the use of different assumptions. However, these figures also show that, after several years, the forecast for the economically feasible gas production is significantly below 70 bcf per year and thus fails to meet the assumed demand profile. It is important to reiterate that the scope of this study focuses on the proved developed and proved undeveloped reserves categories and by design ignores the impact of a potential gas development project that is currently considered in the contingent or prospective resources categories.

## Studies Compared

Since 2009, the Division has released four studies evaluating Cook Inlet gas reserves and Estimated Ultimate Recovery (EUR). Reserves were calculated in different ways and assigned to different categories in the four studies. For example, DNR's 2018 study incorporated future supplies by formulating hypothetical development projects required to produce undeveloped volumes and estimate each project's economic viability.

For comparison, estimated reserves were shown as a single figure for each study (Figure 12). There was an overall upward trend in EUR for Cook Inlet but had not always increased from one study to the next. This is an example of reserves growth, a common phenomenon in producing basins as they mature, where continuing investment in producing fields yields more production than could be forecasted earlier in field life.

**Figure 12. Division of Oil and Gas Studies Compared**




For 2022, decline curve and type curve analyses indicate there is 820 bcf of remaining 1P (proved) reserves, including dry gas and associated gas that can be recovered from currently existing pools (truncated calculated Mean Case). As of December 31,2021, the Cook Inlet basin cumulatively produced 8,876 bcf of gas. Combining the remaining 1P (proved) reserves to cumulative gas produced provides an EUR of 9,696 bcf for the Cook Inlet basin (truncated calculated Mean case). This study does not attempt to estimate 2P and 3P reserves, which would include more speculative gas volumes.

These results do not include the gas discovered at Cosmopolitan, where promising gas test rates bode well for future additions to the Cook Inlet gas reserves base. Proprietary early-stage volumetric estimates for these projects will continue to be refined as development proceeds, but at this point, there is no production history for quantifying gas reserves through decline curve analysis.

## Summary

This report summarizes an integrative effort to quantify remaining gas reserves in Cook Inlet. The forecasting methodology provides a probabilistic assessment of forecasted currently producing pools and pools under development. It also aims at reducing the variance in gas production forecasting by applying some stricter criteria on expected production.

This approach could potentially lead to a more conservative look at the future, but ultimately it is one that assigns appropriate weight to current production to capture operational and reservoir trends observed in the past and incorporates production from expected field development.

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