ALASKA UTILITIES WORKING GROUP

PHASE I ASSESSMENT: COOK INLET GAS SUPPLY PROJECT

June 28, 2023

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ADNR	State of Alaska Department of Natural Resources
AECO	Alberta Energy Company; Alberta hub natural gas price.
AGDC	Alaska Gasline Development Corporation
AEA	Alaska Energy Authority
BCF	Billion cubic feet
BRG	Berkeley Research Group
BV	Black and Veatch
CEA	Chugach Electric Association
CINGSA	Cook Inlet Natural Gas Storage Alaska
DES	Delivered ex-ship
EV	Electric vehicle
FEED	Front-end engineering design
FID	Final investment decision
FOB	Free on Board (loaded onto vessel)
FSRU	Floating storage and regasification unit
GVEA	Golden Valley Electric Association, Inc
HEA	Homer Electric Association
HH	Henry Hub
IGU	Interior Gas Utility
JBER	Joint Base Elmendorf-Richardson
JCC	Japan Customs Cleared
JKM	Japan Korea Marker

KGFGS	Kenai Gas Field Gas Storage
KBPL	Kenai Beluga Pipeline System
LNGC	LNG carrier
m^3	Cubic meter
MEA	Matanuska Electric Association
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMgal/d	Millions of gallons per day
Mtpa	Million tonnes per annum
MW	Megawatts
PCGS	Pretty Creek Gas Storage
SRGS	Swanson River Gas Storage
USCG	U.S. Coast Guard
USDOT FHWA	US Department of Transportation Federal Highway Administration
WCSB	Western Canadian Sedimentary Basin

1 EXECUTIVE SUMMARY

1.1 Background and Scope

1. Southcentral Alaska, along with the Interior (the "Railbelt"), comprise the most densely populated areas of the State. These regions have relied on natural gas produced in Cook Inlet to various degrees to supply its heating and power generation needs since the 1950s. Gas production in Cook Inlet field peaked in the mid-2000s at around 200 BCF per year,[1] and has steadily declined to the current annual production of approximately 70 BCF per year.[2] Formerly active export facilities of Agrium Kenai Nitrogen Plant and Kenai LNG stopped operating in 2007[3] and 2015,[4] respectively, due to the shortage and cost of gas produced in the region.

2. Over the last decade, Hilcorp Alaska, LLC ("Hilcorp") has become the largest operator and gas supplier in the state, maintaining and stabilizing Cook Inlet gas production after a period of threatened shortages.[5] Hilcorp has invested over $750 million in Cook Inlet drilling and capital projects since 2012, and plans to continue the investment at around the same pace over the next decade.[6] In April 2022, Hilcorp first warned of uncertainty of future Cook Inlet natural gas supplies, stating that "gas purchasers [were] not to rely on Hilcorp for gas beyond existing contracts."[7]

3. In May 2022, ENSTAR Natural Gas ("ENSTAR"), Chugach Electric Association, Inc. ("CEA"), Interior Gas Utility ("IGU"), Matanuska Electric Association, Inc. ("MEA"), Homer Electric Association, Inc. ("HEA"), and Golden Valley Electric Association, Inc. ("GVEA"), along with the State of Alaska Department of Natural Resources ("ADNR"), and the Alaska Energy Authority ("AEA")[8] formed a working group to assess future gas supply needs and energy security in Cook Inlet ("Working Group"). The Working Group's stated goal is to:

> *"[w]ork together for long-term solutions. This requires better understanding of each utility's constraints and needs based on existing contracts and forecasting our*

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[1] State of Alaska Department of Natural Resources, Division of Oil & Gas, *Cook Inlet Natural Gas Availability*, March 2018, p. 19, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/CI_Natural_Gas_Availability_Study_2018.pdf.

[2] State of Alaska Department of Natural Resources, Division of Oil and Gas, *2022 Cook Inlet Gas Forecast*, January 2023, pp. 10 and 17, ("2022 Cook Inlet Gas Supply Study").

[3] Reuters, *Agrium closes Alaska plant, blames gas shortage*, September 26, 2007, https://www.reuters.com/article/agrium-alaska-idUSWEN126820070925.

[4] EIA, Natural Gas Weekly Update, *Alaska is a major natural gas producer, but little of the natural gas reaches market*, May 27, 2021, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/05_27/.

[5] Bradner, Tim. *Study says Inlet gas discoveries won't stop shortage*, Alaska Journal of Commerce, March 22, 2012.

[6] Saugier, Luke, *Presentation to Alaska State Legislature*, House Energy Committee, p. 5, January 2023.

[7] DeMarban, Alex, *Hilcorp Warms Alaska utilities about uncertain Cook Inlet natural gas supplies*, Anchorage Daily News, May 17, 2022.

[8] ADNR and AEA participated in advisory capacity in order to provide information to the utilities, as well as remain aware of the effort. These agencies did not fully participate in the deliberations or scoring of the options.

collective demand growth into the next decade as well as considering additional options to meet the unique energy needs of our region."[9]

4. In furtherance of these goals, the Working Group, through ENSTAR, engaged Berkeley Research Group ("BRG") to conduct a planning assessment to: (i) develop scalable options to fill the natural gas supply gap anticipated to occur as Cook Inlet production declines, including Alaska-based options; (ii) develop and assess high-level project scope, cost estimates, and time to execute for each of the options; (iii) for options requiring LNG imports, analyze the available sources for the required annual volumes of gas, potential contract structure and price ranges; (iv) assess key risk and mitigations associated with each option; and (v) develop a ranking system, ranked assessment of options, and recommendations, all of which comprises the advisory engagement titled "Phase I Assessment."

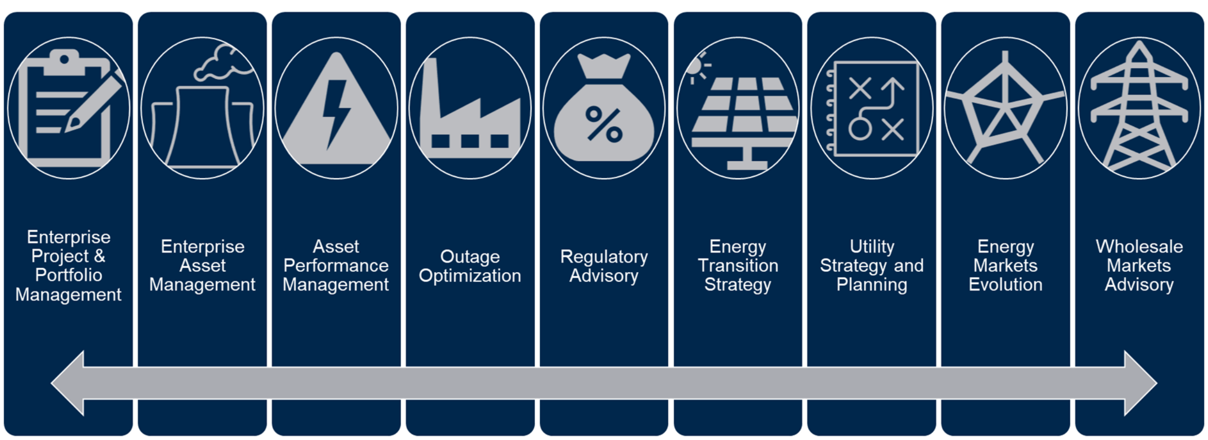
5. This report summarizes the outcomes and recommendations of the Phase I Assessment.

1.2 BRG Credentials

6. BRG's expert Energy & Climate and Project Development Advisory practices combine gas and LNG market, commercial, contractual, and project financing expertise capabilities in technical project development and project management systems. Our advisory practice experts have deep experience in evaluation and development of LNG terminals and regasification facilities, utility infrastructure and major project management, market analysis and contracting. We also excel in providing strategic, market, commercial, economic, and financial advisory services in the global oil and natural gas industry.

7. The areas of focus for our utility clients are summarized in Figure 1.

Figure 1: Areas of Focus for Utility Clients



[9] Regulatory Commission of Alaska, *Affidavit of John D. Sims*, p. 3, November 9, 2022.

8. Appendix A.1. details BRG's relevant engagements and experience in project analysis, management, and design within the global oil and natural gas industry.

1.2.1 Project Leadership

9. The following key experts from BRG and Cornerstone Energy Services, a subcontractor engaged by BRG, led the Phase I Assessment.

Key Staff	Position	Key Role
Steve Means	Managing Director, Infrastructure Development	Infrastructure Development subject matter expert, technical integration
Lieza Wilcox	Director, Project Manager	Project Management, Commercial Assessment Lead
Steve Sawyer	Engineering Project Management	PM, Pipeline Engineering, Construction Management

10. In addition, the team included BRG and Cornerstone staff with deep experience in LNG systems engineering, siting, and processing, pipeline engineering and materials, worldwide gas and LNG market analysis and contracting, energy macroeconomic, investment analysis, financial modeling, and market research.

1.3 Summary of Conclusions

11. Based on the results of this Phase I Assessment, we make the following conclusions:

12. Cook Inlet gas cannot fully meet demand forecast beyond 2026 with current proved reserves or beyond early/mid 2030s assuming incremental local supply development.[10]

13. While continuing to work on Cook Inlet options, other project(s) must be pursued due to lead time to implement.

14. It is vital for the Alaska utilities to have control of the pace of the option development due to the impending gas shortage. Therefore, options that can be approved and either sourced or executed by the utilities are preferrable.

15. Shifting away from local gas supply will require supply options of either scalable or temporary ("stopgap") nature. Expanded underground gas storage will play a critical role in ensuring deliverability of seasonal gas supply with most alternatives.[11]

[10] Demand projections are based on the utilities Working Group's estimates, as described below in this report.

[11] The cost, design, or potential location(s) of this storage expansion have not been taken into account in Phase I Assessment.

16. In order to meet the expected supply shortfall, one or more options need to be selected to progress to an active engineering effort by the end of 2023. In order to meet the expected gas shortfall in 2027-2028, there is a limited set of options that can deliver, namely LNG imports in various forms, and all of them are still at a stage where uncertainties and risks related to design and feasibility need to be resolved before choosing a specific design configuration. Other options, such as a gas pipeline from the North Slope, can meet long-term demand most economically, but are not expected to be online by 2027-2028 or even reach a construction decision in the timeframe where alternatives would need to be sanctioned.[12] This drives the potential need to make progress on multiple fronts. Several viable options to supplement Cook Inlet gas supply need to be progressed further in the next phase of this project ("Phase II") to enable a sanction decision on at least one option by the end of 2023.

1.4 Recommendations

17. BRG recommend the following scope of work as part of "Phase II", estimated to take 4-6 months:

    a. Utilities individually continue to work with Cook Inlet producers and the State to promote and secure additional contracted supply and promote alternative development.

    b. The Working Group should continue to pursue top-scoring options to further define scope, schedule, and commercial viability; specifically: 1) Modification of existing Kenai LNG facilities (via commercial discussions with owner); 2) Scope definition and planning for FSRU option; 3) Greenfield site selection and feasibility assessment for LNG imports if retrofit options become unavailable; 4) Market survey to further define availability and cost of LNG; and 5) Optimization and feasibility assessment of the In-State Pipeline option with AGDC and State of Alaska in areas of permitting critical path and financing structure.

    c. Complete permitting due diligence of all top-scoring options and identify key bottlenecks and showstoppers.

    d. For all top-scoring options, develop draft venture model, project finance structure and plan of engagement with capital markets.

    e. Refine cost of supply estimates for the top-scoring options, including greenfield LNG import, if existing infrastructure in Nikiski becomes non-feasible or excessively risky.

    f. Select one permanent solution or multiple short and long-term options to pursue by the end of 2023 with target date for first delivery of gas in 2027-2028. Phase II

[12] The timeline of feasible start dates and cost of supply ranges for various options are presented in Appendix D, which was assembled by CEA as a collaborative work product between BRG and BV based on each company's separate analyses, and illustrates a multitude of considered options with their feasible start dates.

refinement of scope and schedule will enable a more accurate estimate of feasible start dates for the options under consideration.

1.5 Structure of the Report

18. The remainder of this report is organized into five primary chapters, as follows:

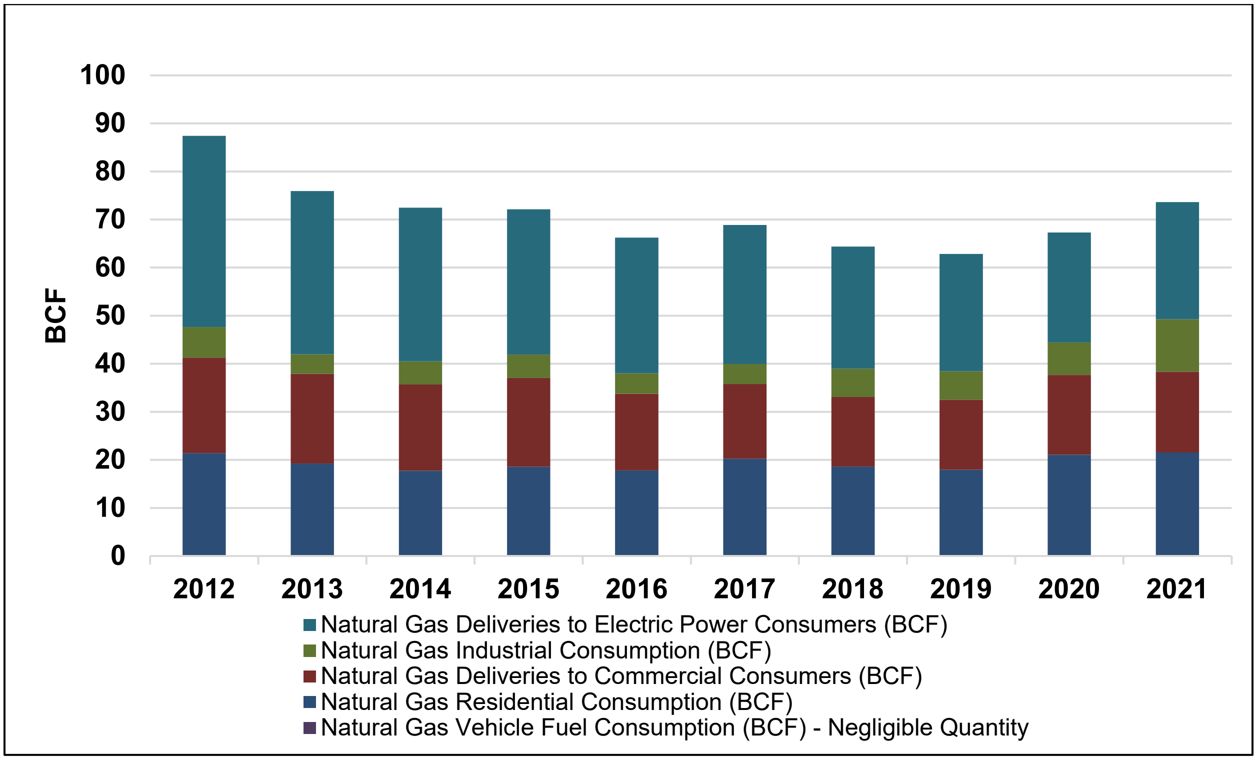
- Chapter 2: Forecast of Unmet Gas Demand Need
- Chapter 3: New Supply Options Considered
- Chapter 4: Option Selection
- Chapter 5: Market, Price Volatility, and Risk Analysis
- Chapter 6: Recommendations and Next Steps

2 FORECAST OF UNMET GAS DEMAND NEED

2.1 Historic and Current Demand for Natural Gas by the Working Group Utilities

19. After the end of fertilizer production and export, Alaska natural gas consumption in the Railbelt area decreased to around 70 billion cubic feet per year ("BCF") over the last decade, divided between residential and commercial heating, power generation, and the rest for small industrial users, such as Kenai Refinery owned by Marathon Petroleum Corporation ("Marathon"). The chart below breaks down the various consumer uses of natural gas.

Figure 2: Alaska Natural Gas Delivered to Consumers



2.2 Incorporation of Renewable Energy Scenarios into Power Generation Utilities' Forecasts

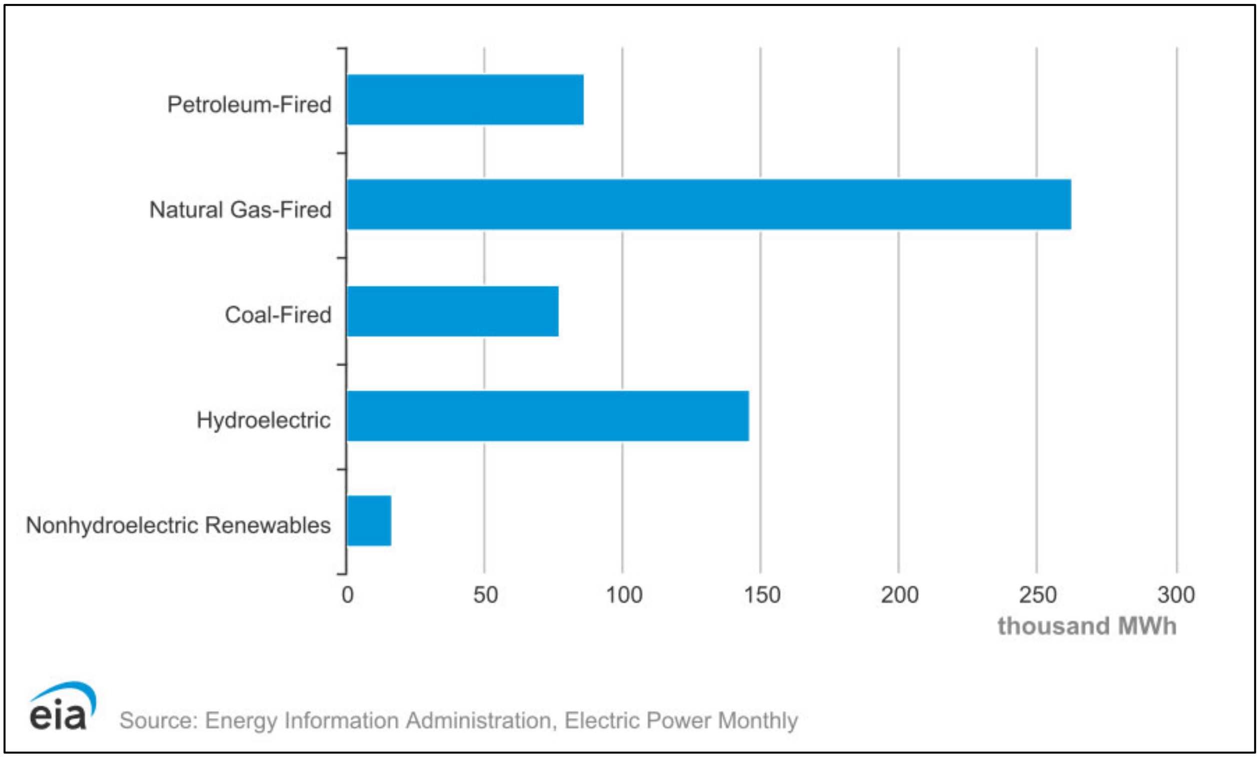
20. Renewable energy has been a part of Alaska's power generation portfolio for decades, with hydropower supplying more than 20 percent of the state's electrical energy in an average year. The integrated Railbelt system is powered by approximately 85% fossil fuels and 15% renewables.[13] The largest renewable energy project supplying the Working Group of utilities is Bradley Lake, at 120 megawatts ("MW") installed capacity. The project supplies about 10% of

[13] Bettina Chastain (CEA Board President) and Arthur Miller (CEA CEO), Opinion: *Anchorage's electric utility is making progress on its clean-energy goals*, Anchorage Daily News (April 13, 2023).

the Railbelt's electricity demand.[14] Several new projects, some of them very large, are in various stages of development.[15]

21. Solar and wind generation has gained footing in the state as well, starting to supply a significant part of electric generation produced in the entire state, as shown in the chart below.

Figure 3: Alaska Net Electricity Generation by Source (December 2022)



22. All electric utilities in the working group have incorporated plans for integration of renewables into their generation portfolio as part of their strategic and near-term plans. For example, CEA is currently evaluating two proposed utility-scale projects (one wind, one solar), that could provide up to 400,000 MWh, or 20% of their annual energy needs, provided that the ongoing feasibility studies can show no negative impact on electricity rates.[16] GVEA's plan to incorporate more natural gas generated electricity into its system would offset the decrease in natural gas demand from using more renewable power generation in the Railbelt. Also, Alaska's currently

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[14] Kirong, N., *Alaska utilities plan $200M Railbelt transmission system upgrades*, S&P Global, May 30, 2022.

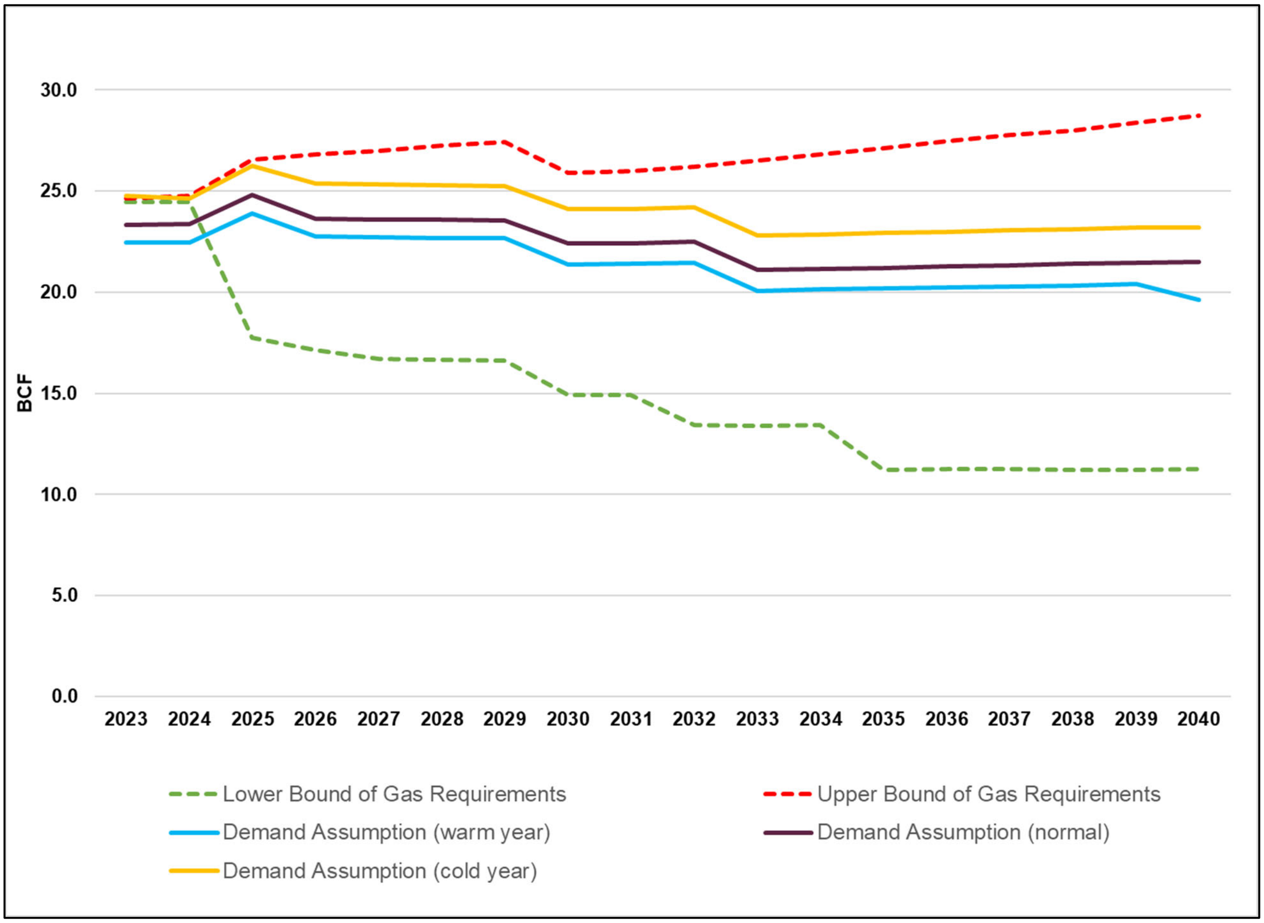
[15] Corri A. Feige (ADNR Commissioner) and Lucinda Mahoney (Alaska Department of Revenue Commissioner), *Investing in Alaska Beyond ESG,* January 2022, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/Alaska_ESG_Jan_2022.pdf.

[16] Bettina Chastain (CEA Board President) and Arthur Miller (CEA CEO), Opinion: *Anchorage's electric utility is making progress on its clean-energy goals*, Anchorage Daily News (April 13, 2023).

relatively low (0.2%) penetration of electric vehicles ("EV"), heat pumps, and induction cooking will likely grow over time and increase combined-cycle natural gas power generation demand overall. [17]

23. Figure 4 below provides a breakout of the projected electric utility[18] natural gas requirements. These requirements (represented by dotted lines) are based on planning scenarios to provide a range for strategic planning. As can be seen, there is a substantial range of projected gas requirements for the electric utilities attributed to potential varying degrees of clean energy uptake along with beneficial electrification such as EVs and heat pumps. For the purposes of project requirements, the three demand lines between the Lower and Upper Bounds of Gas Requirements were utilized since they best represent reasonable expectations and timelines.

Figure 4. Power Generation: Demand Planning Assumptions vs. Potential Bounds of Gas Requirements



[17] Alaska Energy Authority, *State of Alaska Electric Vehicle Infrastructure Implementation Plan* (approved by USDOT FHWA on September 27, 2022), pp. 25-26.

[18] CEA, MEA, HEA, and GVEA.

2.3 2022 Cook Inlet Gas Supply Study by the Department of Natural Resources

24. In the 2022 Cook Inlet Gas Forecast,[19] ADNR evaluates 90 oil and gas pools in the Cook Inlet Basin within 38 different fields and developed probabilistic forecasts for proved developed and proved undeveloped dry and associated natural gas reserves for each pool.[20] The study assesses reserves based on "present conditions and assumptions"[21], and "does not estimate future natural gas prices".[22] Undeveloped reserves are assumed to be developed at a drilling pace of 15 wells per year from 2023 until 2030, with no additional drilling assumed thereafter.[23] ADNR's assumed annual gas demand is 70 BCF; it is a "steady demand profile" assumption[24] and thus does not make judgments regarding any potential changes in future natural gas demand.

25. ADNR truncates forecasts of the technically recoverable gas to account for the economic limit of the various pools. The economic limit ensures that the production forecasts are limited to only economically feasible production. This is typically determined as the difference between revenues and variable costs borne by the producer.[25] Since ADNR does not forecast future prices in this study, it is implied that production for various pools will be truncated based on the economic limits determined under the prevalent price conditions. ADNR estimates that under the mean truncated ("ADNR's 2022 Mean Truncated") production scenario there are currently 803 BCF of dry natural gas and 17 BCF of associated natural gas remaining in Cook Inlet.[26]

[19] State of Alaska Department of Natural Resources, Division of Oil and Gas, *2022 Cook Inlet Gas Forecast*, January 2023, ("2022 Cook Inlet Gas Supply Study").

[20] 2022 Cook Inlet Gas Supply Study, p. 4.

[21] 2022 Cook Inlet Gas Supply Study, p. 3.

[22] 2022 Cook Inlet Gas Supply Study, p. 3.

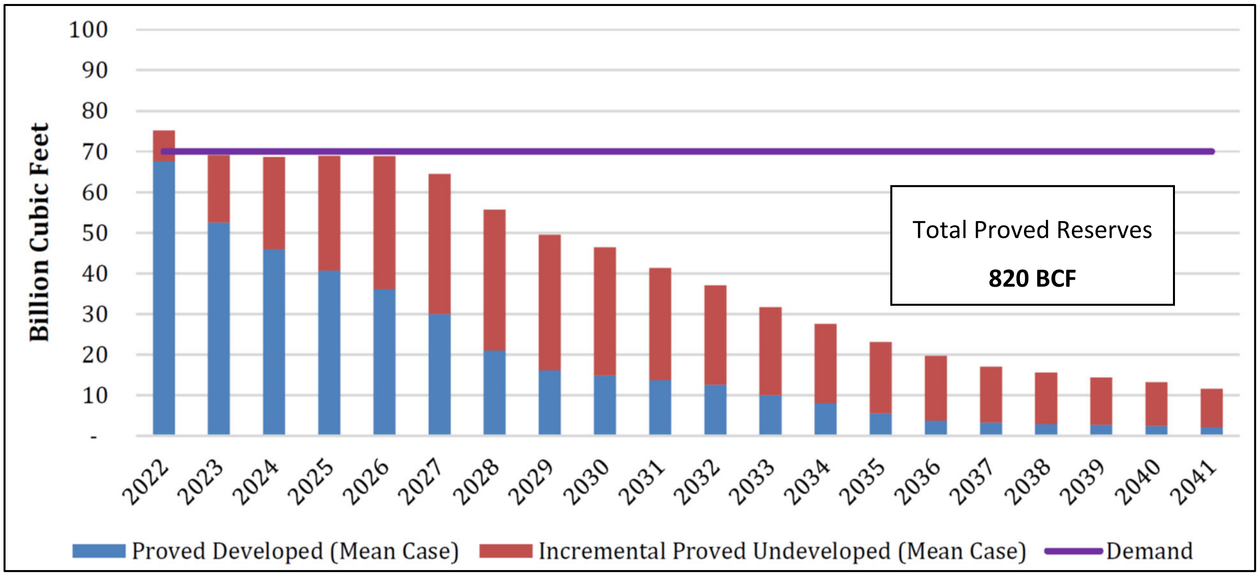
[23] 2022 Cook Inlet Gas Supply Study, p. 4. "The forecast does not assess or assume how many wells may be drilled after 2030."

[24] 2022 Cook Inlet Gas Supply Study, p. 17.

[25] ADNR did not analyze the potential economic limit of the entire basin that would take into account ability to sustain a support industry and interactions between upstream and midstream, such as maintaining pipeline pressures.

[26] 2022 Cook Inlet Gas Supply Study, p. 15.

Figure 5: ADNR's 2022 Mean Truncated Annual Gas Supply Forecast



2.4 Unmet Gas Demand Forecast

26. The main gas consumers in Cook Inlet are ENSTAR and CEA and together account for more than 75% of gas demand in Cook Inlet. ENSTAR is the largest overall consumer of natural gas in the state and does not expect material shifts in its demand over the next 20 years. ENSTAR's 2023 contracted demand is approximately 34 BCF. CEA has contracted approximately 8 BCF with an additional 8 BCF sourced from Chugach's 66.7% working interest ownership in the Beluga River Unit. Other major gas consumers include MEA, HEA, GVEA as purchaser of economy energy sales from Cook Inlet basin, and Marathon as an industrial user for local refinery. In addition, IGU located in Fairbanks, currently supplies Cook Inlet sourced gas to Fairbanks via an LNG trucking operation. IGU has concluded a firm 20-year contract with Harvest Midstream to supply LNG from the North Slope starting approximately in 2024, with two 5-year extension options.[27] IGU's future demand outside of its current Cook Inlet gas contracts is thus excluded from the estimated demand profiles. However, should IGU choose to participate in the selected supply option, its demand could be easily incorporated into the design of the top-ranked options under consideration.

27. Future "Unmet Gas Demand" can be defined in two ways:

[27] IGU Board of Directors Special Board Meeting, January 17, 2023, *IGU Board Memorandum 2023-01*, p. 8. IGU's current gas contract with Hilcorp provides sufficient gas through 2032, however in the event of the gas supply source switching to Harvest, the Cook Inlet contract will end earlier, as shown in Figure 6.

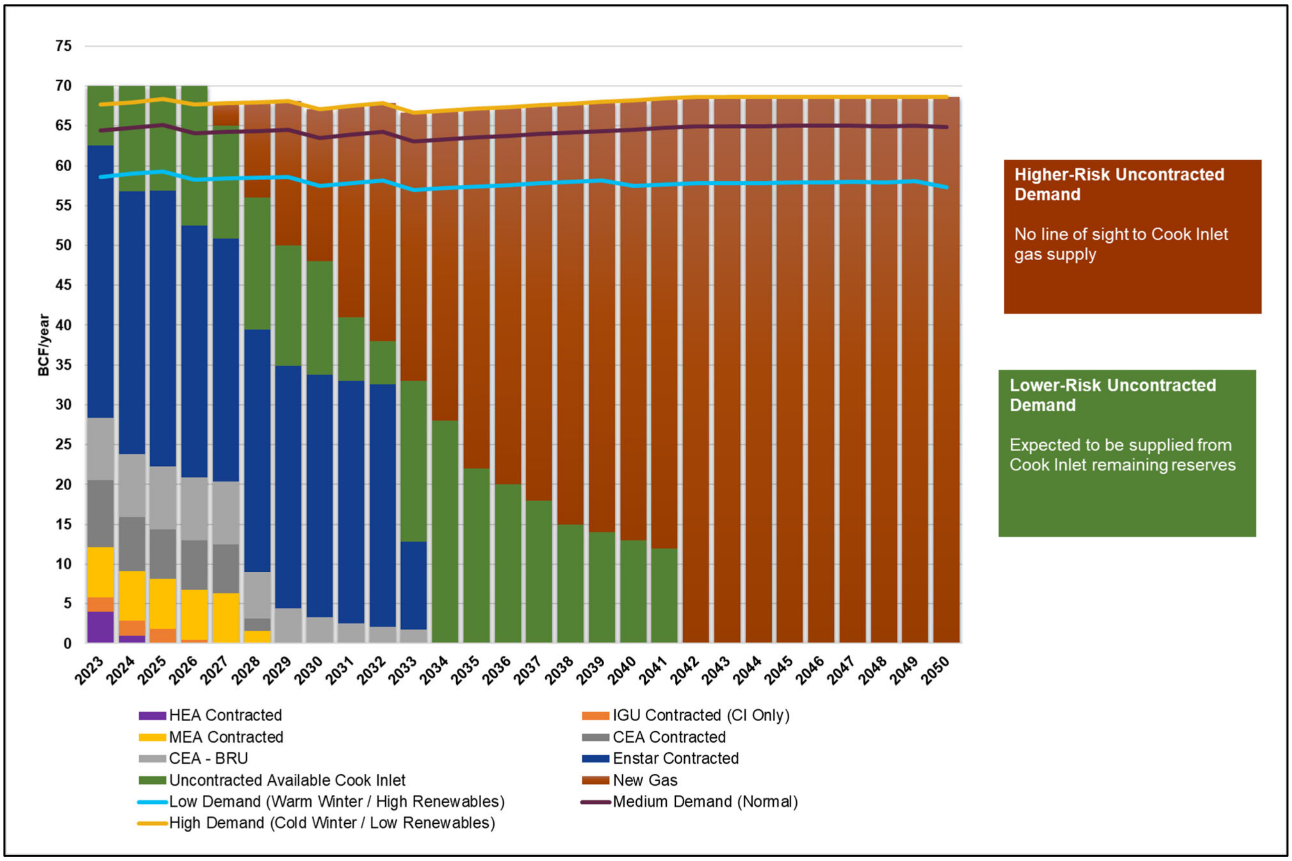
a. Lower-risk uncontracted demand compares consumer demand forecasts to firm contract quantities committed to Alaskan utilities with access to the Cook Inlet gas market; or

b. Higher-risk uncontracted demand compares consumer demand forecasts with ADNR truncated production, which assumes that utilities are able extend or execute new agreements up to the proved reserves production profile provided by ADNR.

28. BRG used the second definition as the planning assumption in this assessment to determine Unmet Gas Demand, since ADNR's 2022 Mean Truncated forecast is based on reserves of high degree of confidence (1P) that can be delivered at current prices. In other words, this assessment assumes that additional Cook Inlet gas will be contracted and re-contracted up to ADNR's 2022 Mean Truncated production profile. ADNR's 2022 Mean Truncated production profile[28] along with demand forecasts provided by utilities are depicted in Figure 6.

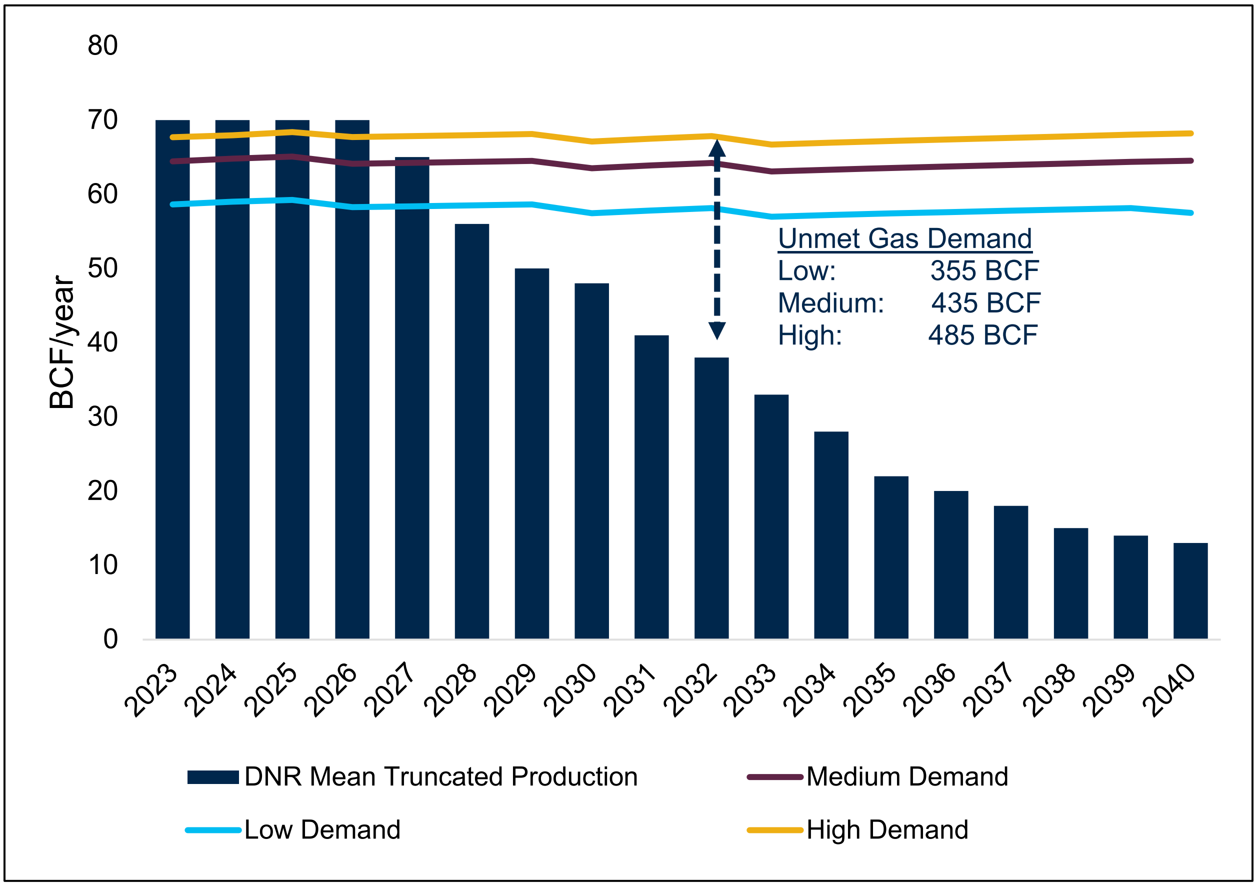
[28] This is the Base Case for the gas supply forecast that is based on ADNR's 2022 Mean Truncated Annual Gas Supply Forecast which BRG digitized with the values rounded and truncated after 2040.

Figure 6. Utilities' Contracted and Uncontracted Demand vs Cook Inlet Supply



29. The difference between these assumed supply and demand forecasts is the Unmet Gas Demand assumed by BRG for the purposes of sizing a potential natural gas replacement project and calculating the costs of supply per Mcf, as depicted in Figure 7. The assumed demand stays relatively flat for each of the High, Medium, and Low scenarios after 2040 as a planning assumption for the purpose of sizing a project that is capable of delivering up to each respective demand assumption and for calculating 20-year levelized costs of supply per Mcf.

Figure 7: ADNR's 2022 Mean Truncated Natural Gas Supply and Utilities' Demand Forecasts



30. Subject to the risks described below in Section 2.5, and in order to evaluate the project options on a comparable basis, the Working Group and BRG adopted the following range of Unmet Gas Demand as part of this assessment, presented graphically in Figure 8 and in Table 1 below.

Figure 8: Unmet Gas Demand for Low, Medium, and High Demand Scenarios

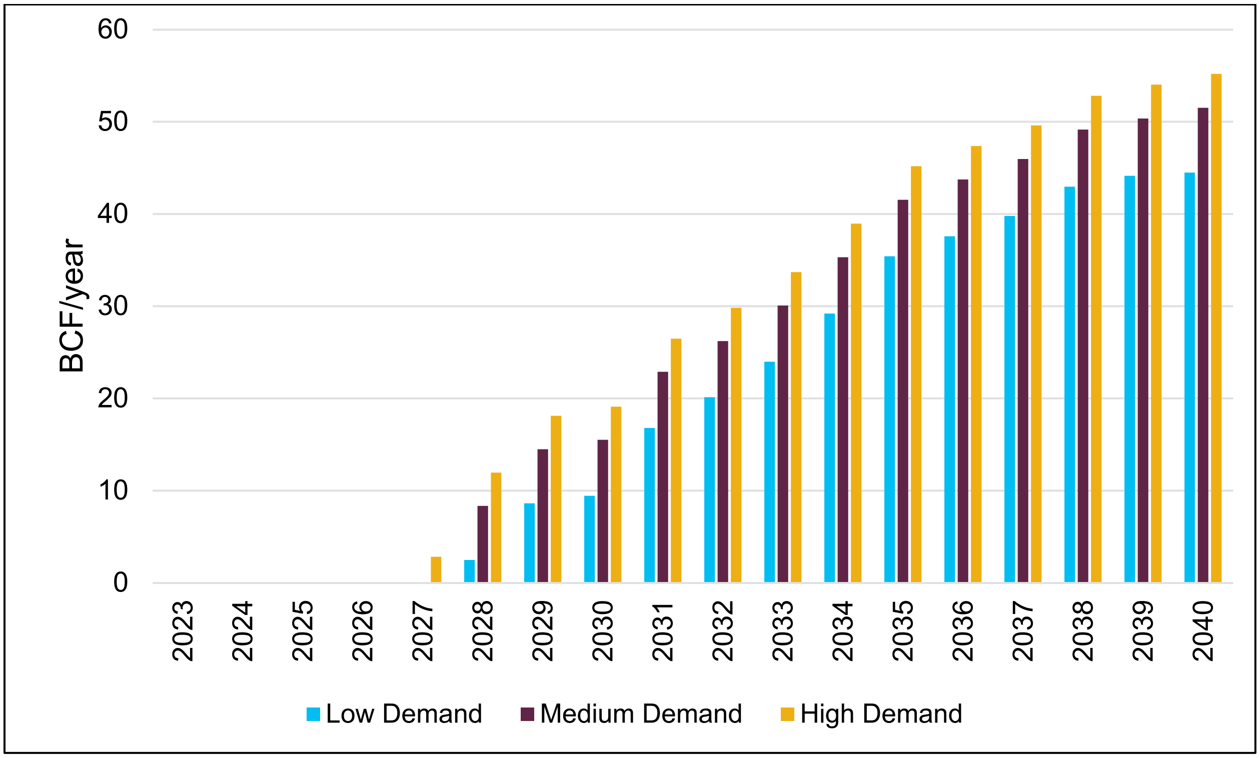


Table 1: Unmet Gas Demand by Year (BCF)

	Low Demand	Medium Demand	High Demand
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	3
2028	2	8	12
2029	9	14	18
2030	9	16	19
2031	17	23	26
2032	20	26	30
2033	24	30	34
2034	29	35	39
2035	35	42	45
2036	38	44	47

	Low Demand	Medium Demand	High Demand
2037	40	46	50
2038	43	49	53
2039	44	50	54
2040	44	52	55

2.5 Uncertainties of the Unmet Gas Demand Forecast.

31. The main uncertainties associated with Unmet Gas Demand include:

a. The actual quantity of remaining reserves and resources that could be developed to fill a portion of the Unmet Gas Demand. Proved developed and proved undeveloped reserves, used in the ADNR study, are generally considered to be reserves of high confidence and likelihood of commerciality.[29] However, it is possible that the ultimately recoverable reserves will end up materially higher or lower than ADNR's 2022 Mean Truncated estimate resulting in smaller or larger Unmet Gas Demand over the next thirty years.

b. The pace of Cook Inlet development needs to be sufficient to bring resources online in time to satisfy the demand in a particular year. The ADNR study assumed a drilling rate of 15 development wells based on historic development drilling activity in Cook Inlet. Lower drilling activity would likely result in higher Unmet Gas Demand and a different production profile than what was anticipated by ADNR.

c. Anticipation of additional supply entering the Cook Inlet market could influence the rate of development activity by Cook Inlet producers (i.e. slowing down drilling programs). This could potentially result in a steeper production decline for proved reserves than currently anticipated over the entire forecast window.

d. The Unmet Gas Demand contains projections of household, commercial, and industrial consumer gas demand in the future, and thus is inherently uncertain.

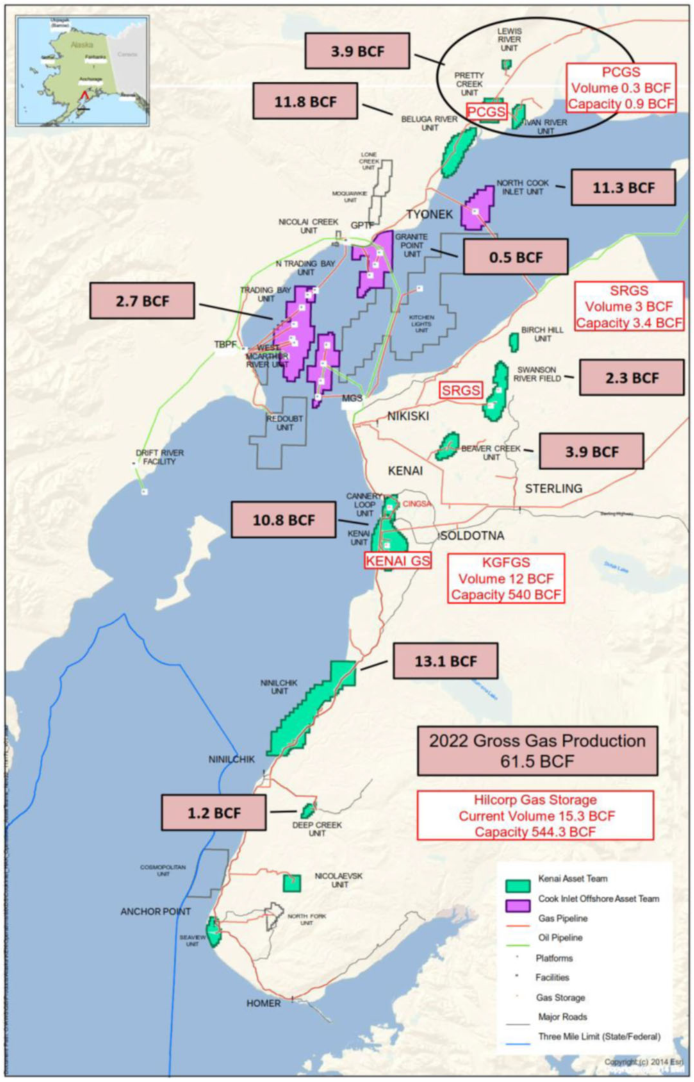
e. Finally, the adoption rate of renewable power generation by utilities can have significant impacts on the resulting overall demand for natural gas, particularly in the later portion of the demand forecast window of 2023-2050. The upper and lower bounds of potential outcomes in utility gas demand impacted by levels of renewable power penetration are shown above in Figure 4.

32. The Cook Inlet market will have additional storage requirements to meet seasonal, daily, and hourly demand obligations. The Unmet Gas Demand presented in this study is quantified on an

[29] 2022 Cook Inlet Gas Supply Study, p. 7.

annual basis; however, adequate storage capacity and deliverability needs to be in place to ensure the demand is met on the coldest days of the year. The Cook Inlet Natural Gas Storage Alaska ("CINGSA") facility has a current design capacity of 11 BCF. Additionally, Cook Inlet gas storage capacity held by Hilcorp is depicted in Figure 9 below as part of all storage and producing fields. Hilcorp-owned storage fields are Swanson River Gas Storage ("SRGS"), Pretty Creek Gas Storage ("PCGS"), and Kenai Gas Field Gas Storage ("KGFGS").[30]

Figure 9: Hilcorp's Cook Inlet Gas Storage and Production Capacity[31]



33. The timing of when Cook Inlet will first require additional sources of gas and the Unmet Gas Demand profile have significant implications on the schedule and the cost of meeting this

[30] All storage assets are depicted as white boxes with red borders and text on the map below.

[31] Hilcorp Presentation to the House Energy Committee – Luke Saugier, Senior Vice President, Alaska, January 2023.

shortfall. Some of the long lead-time options which are described in subsequent chapters have longer development timeframes than what is necessary to meet the Unmet Gas Demand in 2027 and 2028. Furthermore, the Unmet Gas Demand increases from less than 10 BCF in the medium demand case in 2028 to over 50 BCF in 2040. Large scale developments could be underutilized in early years leading to higher overall cost of supplying the gas.

34. Continued close coordination within the Working Group and with the project management team as project options are developed further is essential to ensure the most efficient timely implementation of solutions to fill the Unmet Gas Demand during this generational energy system transition.

3 NEW SUPPLY OPTIONS CONSIDERED

35. In this chapter, we review the scope of the project options considered by BRG to fill the Unmet Gas Demand need starting at first occurrence and continuing to 2050 and beyond.

3.1 Project Options

36. The main options for supplying Unmet Gas Demand considered in this Phase 1 Assessment are shown in the table below. These options were originally proposed by BRG as the most viable based on previous studies and market knowledge and were expanded and modified in cooperation with the Working Group from original six options to ten. Other options to fill the Unmet Gas Demand were evaluated by CEA and its consultant Black and Veatch ("BV") as part of a separate study; the summary of all options evaluated is presented in Appendix C.

Table 2: Project Options Considered

#	Project Option	Short Title
1	Development of additional regional gas supply	Cook Inlet Gas
2	Alaska in-state pipeline	In-state Pipeline
3	LNG imports using existing Kenai LNG infrastructure	Kenai LNG
4	LNG imports or spot or seasonal contracted cargos via a green-field port and regas facility	Greenfield Port and Regas
5	LNG imports via a Floating Storage and Regasification Unit ("FSRU")	FSRU
6	LNG imports via barge or small vessel	Barge / Small LNG Carrier
7	North Slope natural gas supply via the Alaska LNG project	Alaska LNG
8	North Slope natural gas supply via LNG trucking or combination of trucking and rail/pipe to CI	LNG Truck and/or Rail
9	Options to supplement natural gas supply with renewable natural gas	RNG
10	Hydrogen and hydrogen-derived fuels	Hydrogen

37. While not reflected in the order of the options listed above, the project options fall into several logical groups based on the source of supply that are frequently discussed together, and may include further variations or sub-options that can be refined and developed in the next stage of implementation. They are:

a. Cook Inlet and Southcentral gas supply (Option 1)

b. Alaska North Slope gas supply (Options 2, 7, and 8)

c. LNG imports (Options 3, 4, 5, and 6)

d. Renewable and low-carbon gas (Options 9 and 10)

3.2 Summary of Option Analysis

38. BRG and Cornerstone analyzed each project option at a sufficiently detailed screening level to enable the prioritization and scoring of the options. The summary of this analysis in the table below highlights the main outcomes of the analysis:

39. **Year Available.** The year that each option is estimated to deliver first gas, assuming that a decision is made in 2023 to progress the option to the next necessary development step. For most project options, the next step is preliminary engineering design, and in some cases Front End Engineering Design ("FEED"), which precedes a Final Investment Decision ("FID").

40. **Max Annual Supply and Demand Met Through [Year].** The Unmet Gas Demand assumed in Phase I Assessment (using High Demand case from the Working Group) begins in 2027 and increases to approximately 20 BCF annually by 2030, and to approximately 55 BCF by 2040. Assuming ADNR's case of mean truncated supply, all Cook Inlet Gas is offline by 2041, necessitating the new supply project to provide up to approximately 70 BCF of gas annually. Some of the options, such as the North Slope gas pipeline projects, have plentiful capacity to meet this demand; LNG Import options are expandable beyond listed initial capacity. All other project options have unique capacity limitations that make them unsuitable for long-term supply reliance, although it is our understanding that utilities with contracts expiring in the short term are considering other short-term options, as detailed in Appendices C and D.

41. **Total CAPEX, $MM.** Total estimated capital investment made by utilities and/or third parties expressed in 2023 prices ("$2023").

42. **Direct Investment, $MM.** Estimated portion of Total CAPEX shouldered by the utilities individually or as part of a joint venture. This figure is subject to change and commercial structure negotiations. The estimate reflects the industry standard or status-quo assumption for each type of project, in $2023.

43. **Indicative Cost of Supply, $2023/Mcf.** For all options, the estimated indicative cost of supply carries an inherent uncertainty at this stage of evaluation, whether or not stated in the table below or further in this report. This is due to the early stage of development of all the options. For some options such as Cook Inlet Gas or North Slope Gas Supply, once in service, costs of supply are likely to stay relatively flat. For projects involving LNG Import, prevailing market will create ongoing volatility in the cost of supply during operations that could be smoothed out with hedging. BRG used the Working Group's high demand case to estimate the cost of supply presented below. This indicative cost of supply compares to the current contract price of Cook Inlet Gas of about $8 per Mcf. Current estimates of the cost of supply do not include potential additional underground storage.

Table 3: Summary of Project Option Analysis

#	Title	Year Available	Max Annual In-State Supply, BCF	Demand Met Through	Total CAPEX, $MM	Direct Investment, $MM	Indicative Cost of Supply, $2023/Mcf		
							Gas	Transport and Processing	TOTAL
1	Cook Inlet Gas	2027	23	2032	$1,500 - $2,000	NA	$9.3 - $25.5	Included	$9.3 - $25.5
2 (a)	In-state Pipeline (Privately owned)	2030	142	After 2050	$8,750	$10	$1.3	$26.8	$28.1
2(b), (c)	In-State Pipeline (Subsidized or State-Owned)	2030	142	After 2050	$8,750	$10	$1.3	$7.8	$9.1
3	Kenai LNG	2028	55	2040	$768	$768	$8.6	$3.4	$12.0
4	Greenfield Port and Regas	2030	55	2040	$877	$877	$8.6	$4.0	$12.6
5	FSRU (Own/Lease)	2027-2029	55	2040	$698	$607 / $201	$8.6	$3.6	$12.2
6	Barge / Small LNG Carrier	2027-2029	25	NA	$563	$158	$8.6	$13.3	$21.9
7	Alaska LNG	2030	182	After 2050	$43,000	$140	$1.3	$3.1	$4.4
8	LNG Truck and/or Rail	2026	10	2028	$796	$346	$2.5	$25.0	$32.0
9	RNG	Unknown	1	NA	NA	NA	$0.0	$25.0	$25.0
10	Hydrogen (green)	2035 or later	Unknown	NA	NA	NA	$0.0	>$32	>$32

3.2.1 Scope Descriptions

44. In this section, we describe the high-level scope of each of the project options considered in Phase I. BRG and Cornerstone provided corresponding supporting cost and high-level project schedules (to be refined in Phase II) to ENSTAR in support of the summary assumptions.

3.2.1.1 Option 1 - Cook Inlet Gas

45. The Cook Inlet Gas option is the estimated quantity of gas that may be available for future contracting in Cook Inlet above and beyond ADNR's 2022 Mean Truncated case.

46. Information on available reserves is generally confidential, and thus we relied on the previous 2018 ADNR Cook Inlet Natural Gas Availability study ("2018 ADNR Study") to estimate the quantifies of gas that may be available beyond the 2022 Cook Inlet Gas Forecast mean truncated supply, and thus also likely above the level of current contract prices. Figure 10 below from the 2018 ADNR study[32] shows total gas supply available at a 15% hurdle rate assumption, including proved reserves. The amount of gas incremental to the rough equivalent of ADNR's 2022 Mean Truncated case is only the portion of the supply above the $8/Mcf price threshold in Figure 10, i.e. around 220 Bcf at the 50th percentile measurement.

Figure 10: 2018 ADNR Cook Inlet Gas Availability Curve

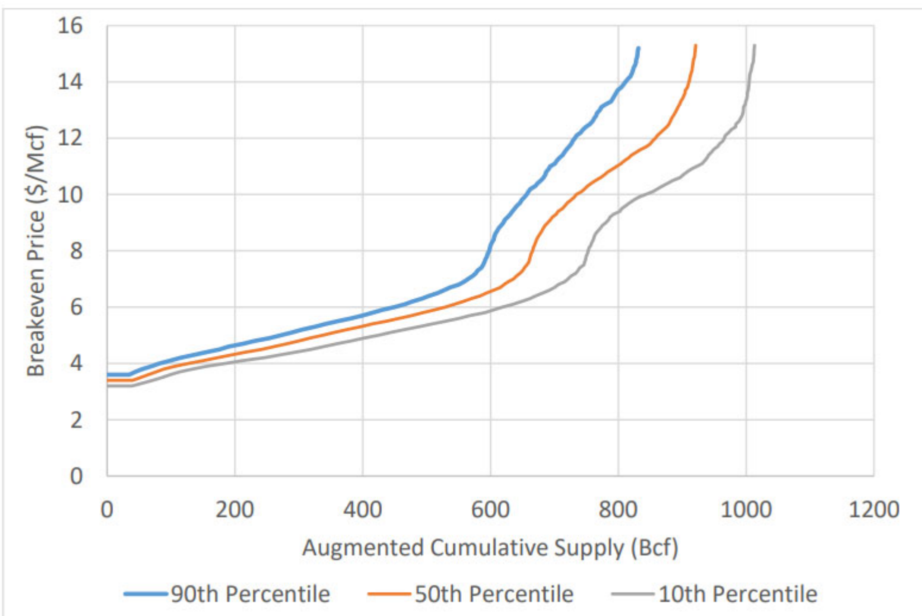


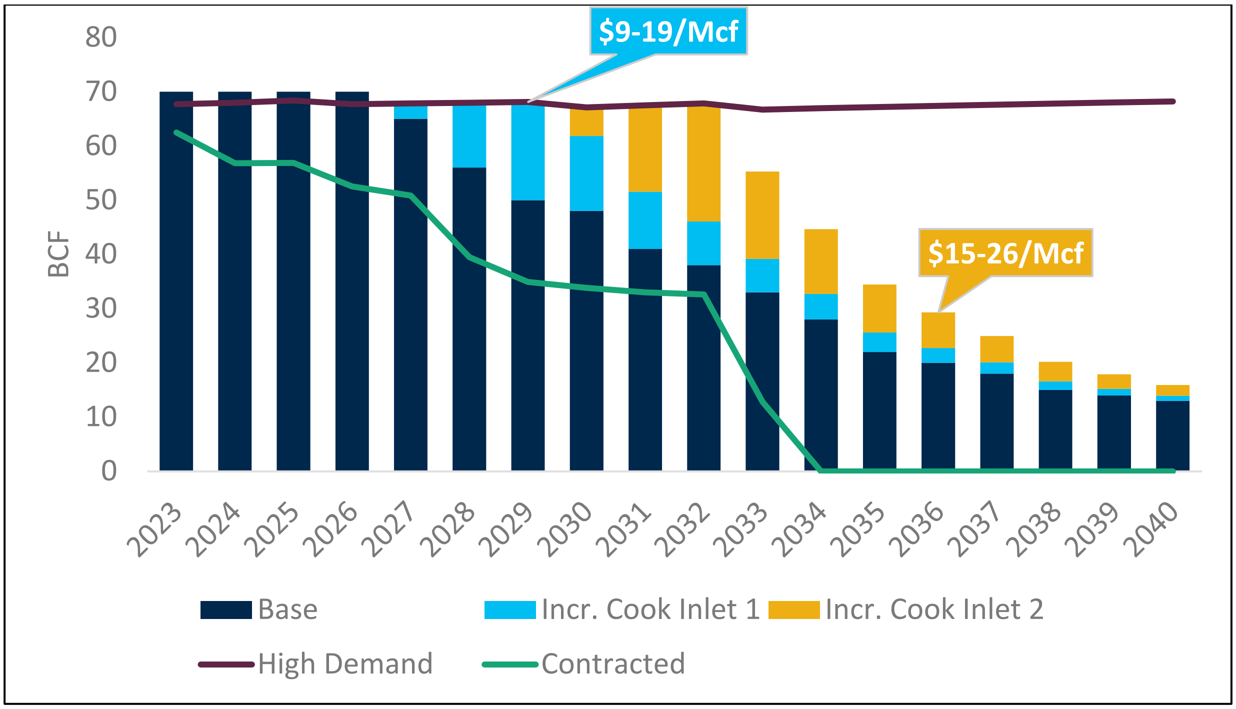
Figure A-1. Cumulative supply from augmented production sources (15% real hurdle rate)

[32] 2018 ADNR Study, p. 34.

47. Due to the vintage of the 2018 ADNR study and the intervening factors such as the stability of remaining proved reserves and prices between the two ADNR assessments, as well as the recent inflationary market signals, we perceive and acknowledge a significant amount of uncertainty in both the quantity of additional gas available, and its potential price. However, after review of the available public information and a consultation with ADNR's technical staff, the estimate of 220 BCF available[33] additional reserves beyond ADNR's 2022 Mean Truncated forecast appears to be a reasonable working assumption using public data.

48. The chart below represents the estimated potential of incremental regional gas supply beyond the ADNR's 2022 Mean Truncated case.

Figure 11: Incremental Regional Gas Supply Estimate[34]



49. The gas supply estimate depicted in Figure 11 consists of reserves and resources with different degrees of commercial and technical confidence. Approximately 466 BCF of already contracted capacity is included as part of the Base profile that represents ADNR's Mean Truncated case.[35] Approximately 287 BCF of uncontracted capacity would also fall within the ADNR's 2022 Mean Truncated case.[36]

[33] Please see Appendix B.2.

[34] Please see Appendix B.2 for production profile and price assumption methodology.

[35] Sum of Base production below the green line.

[36] Sum of Base production above the green line; equal to Sum of Uncontracted Available Cook Inlet from Figure 6.

50. Approximately 188 BCF of 220 BCF incremental production might be developed by 2040.[37] Depending on location, investments by ENSTAR and Harvest Midstream in new pipeline connections may be necessary.

51. This additional supply could come online in Cook Inlet to fill in Unmet Gas Demand beyond proved reserves, starting around 2027. These reserves could be comprised of a mix of onshore, near-shore developments, including installation of new platforms and longer economic life of existing fields. Regional gas supply is provided in the form of contracted agreements where the utility customers incur minimal direct investment. However, the new capital needed to invest in the development of these new reserves is difficult to secure for Cook Inlet operators for various reasons. Based on the interviews conducted by BRG and on public information presented by certain operators during the 2023 Alaska State Legislative session, these reasons include the high cost of securing an offshore or even a new land rig for only a few prospects, overall high operating costs and low availability of service providers, difficulty securing capital for Alaska oil and gas activities based on climate change concerns as well as past fiscal instability, and the overall concentration of the Alaska market under a large owner and operator in Hilcorp. The relatively small and closed gas market generally leads to the dilemma of operators being unmotivated to take substantial risks without a gas contract, utilities unwilling to sign firm gas contracts for unproven reserves, and both parties finding it difficult to land on mutually agreeable prices for new developments with significant cost uncertainty. Recent federal offshore lease sales attracted no new interested producers to Cook Inlet,[38] accentuating the challenge of securing new capital for the region.

52. Working Group utility customers continue to be best positioned to gauge the availability and pricing of incremental Cook Inlet gas supply, as they have access to confidential producer information that is not available to this Phase I Assessment. However, based on the review of public information and in consultation with the Working Group, it is our opinion that it would be risky and unadvisable under current market conditions to count on sufficient Cook Inlet or other regional gas supply to fill the Unmet Gas Demand beyond 2026 without developing alternative supplies.

3.2.1.2 Option 2 - In-State Pipeline

53. The In-State Pipeline option is a variant of the Alaskan Gasline Development Corporation's (AGDC) proposed Alaska Standalone Pipeline (ASAP). The pipeline would run 733 miles to supply natural gas from Prudhoe Bay to ENSTAR's system in Anchorage. AGDC has previously sized this pipeline with a 36-inch diameter to meet a demand of 500 MMcfd to Anchorage and the

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[37] See Appendix B.2 for production profile and price assumption methodology.

[38] Anchorage Daily News, *Hotly debated federal Cook Inlet oil and gas lease sale draws only 1 bid*, Dec. 30, 2022, https://www.adn.com/business-economy/energy/2022/12/30/hotly-debated-federal-cook-inlet-oil-and-gas-lease-sale-draws-only-1-bid/.

surrounding utilities together with an industrial export customer. The design has a ~30 mile, lateral to supply the Fairbanks region.[39]

54. For the purposes of Phase I Assessment, BRG and its sub-contractor, Cornerstone Energy Services, Inc., have assumed that the intent of this In-State Pipeline is to meet *only* local utility and refinery natural gas needs with no initial intent to provide exporting capabilities like that of the Alaska LNG project. Operating under that assumption, BRG has determined that the current 36-inch diameter ASAP pipeline is over-designed and could be optimized to better fit the needs of the state of Alaska. Assumptions made in a preliminary sizing of the ASAP line are outlined in the following section.

Mainline Size

55. The Gas Supply model developed by ENSTAR, in conjunction with the Working Group and Marathon, indicates projected peak-day demand of around 404 MMcfd.

Table 4: Peak Day Demand for Alaska Consumers (MMcfd)[40]

Year	ENSTAR	CEA	MEA	HEA	GVEA	Tesoro	IGU	Total
2023	290.9	43.9	24.4	14.5	2.7	12.1	6.0	**394.5**
2024	290.9	43.7	24.5	13.4	2.7	12.1	6.9	**394.2**
2025	290.9	43.5	24.6	13.9	6.8	12.1	8.0	**399.8**
2026	290.9	40.6	25.0	13.4	6.8	12.1	10.0	**398.8**
2027	290.9	40.3	25.2	13.4	6.8	12.1	11.8	**400.5**
2028	290.9	40.0	25.2	13.4	6.8	12.1	13.6	**402.0**
2029	290.9	39.7	25.4	13.4	6.8	12.1	15.1	**403.4**
2030	290.9	37.5	25.0	14.6	6.8	12.1	16.4	**403.3**
2031	290.9	37.5	25.1	14.6	6.8	12.1	17.4	**404.4**
2032	290.9	37.6	25.3	14.6	6.8	12.1	18.2	**405.5**
2033	290.9	33.5	25.4	14.6	6.8	12.1	18.7	**402.0**
2034	290.9	33.5	25.6	14.6	6.8	12.1	19.0	**402.5**
2035	290.9	33.5	25.8	14.6	6.8	12.1	19.2	**402.9**
2036	290.9	33.5	26.0	14.6	6.8	12.1	19.3	**403.2**
2037	290.9	33.5	26.1	14.6	6.8	12.1	19.3	**403.3**
2038	291.0	33.5	26.2	14.6	6.8	12.1	19.3	**403.5**
2039	291.0	33.5	26.6	14.6	6.8	12.1	19.3	**403.9**
2040	291.0	33.5	26.9	14.6	6.8	12.1	19.3	**404.2**

[39] Davis, Carolyn, Natural Gas Intel, *Alaska Gasline Secures Final EIS for Pipeline Project*, June 22, 2018, https://www.naturalgasintel.com/alaska-gasline-secures-final-eis-for-pipeline-project/.

[40] Working Group input, November 2022.

56. Sized at 36 inches, the 733 miles ASAP pipeline can free-flow 390 MMcfd from Prudhoe Bay to Anchorage while experiencing a pressure drop of < 300 psig. A 36-inch pipeline can handle nearly 100% of Alaska natural gas needs on a peak demand day from first day of operation, and requires no compression or storage to do so. This design is the basis for the project cost estimate used in this report for the In-State Pipeline option. BRG adapted the estimate from the 2014 AGDC FEED results by removing the gas processing plant on the North slope (which also included compression), adding a pipeline from Pt Thomson to Prudhoe Bay, and adjusting for inflation up to $2023.

57. A more economical solution would be to utilize a smaller diameter pipeline and add compression along the mainline as the gas demand increases. Cornerstone has performed some preliminary modeling using GasCalc 5.0[41] that indicates that a 24-inch steel pipeline could accomplish this goal. The 24-inch pipeline provides enough capacity to free-flow gas from Prudhoe Bay to Anchorage at 105 MMcfd, thus supplying average annual Unmet Gas Demand until at least 2034.

Compression

58. Adding compression at key points in the line would provide capacity for the 24-inch ASAP pipeline to flow 390 MMcfd to Anchorage in addition to 60 MMcfd to Fairbanks.[42] This volume, according to the gas supply model, would eliminate the need for any Cook Inlet supply, and thus would likely be subject to a phase-in period of time as Cook Inlet declines.

Infrastructure Requirements

59. The infrastructure requirements and supply sources and strategy are as follows:

- Approx. 800 miles 24-inch steel pipeline from Pt Thomson to Anchorage Beluga Pipeline interconnect
- 30 miles 12-inch steel pipeline to Fairbanks
- ~38 mainline valve sites (for both mainline and Fairbanks lateral)
- Up to 7 mainline compressor stations, as needed

Supply Sources and Strategy

60. Gas to the pipeline would be supplied via a gas purchase agreement with Pt. Thomson gas owners, including potentially State of Alaska as a Royalty-In-Kind gas owner. Placing the pipeline origin at Pt. Thomson, rather than Prudhoe Bay, allows deliver of utility-quality gas with minimal conditioning requirements, [43] thus avoiding a multi-billion expenditure for this In-State Pipeline project.

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[41] Copyright 1993-2023 B3PE LLC Revision: 6.1.35 - March 29,2023.

[42] These volumes represent the scenario modeled to meet peak day demand; however, capacity could be increased further to provide 500 MMcfd and include other industrial customers.

[43] AGDC Board Meeting, February 4, 2021, President's Report, p. 32, available at https://agdc.us/wp-content/uploads/2021/02/02042021_Board-Meeting-Presidents-Report.pdf

Financing and Ownership

61. Even the smaller 24-inch pipeline dedicated solely to filling the Unmet Gas Demand for the Working Group is oversized and expensive compared to other feasible options, such as LNG imports. Current natural gas demand in Alaska simply does not support a pipeline project of about 800 mi in length, if compared strictly on cost to the LNG import option. However, the Working Group recognizes that such a project may still have significant generational benefits due to the ability of the In-State Pipeline project to:

- Supply natural gas to areas of the state currently relying on coal, biomass, or diesel for power generation and heating, and thus experiencing the negative effects of pollution, intense carbon emitting generation, high and volatile costs, or both;
- Generate significant in-state construction and operations jobs;
- Create the ability to supply natural gas to new industrial customers along and nearby the pipeline route, such as mine projects;
- Generate gas royalty revenue to the State of Alaska;
- Aid in extending the life of the North Slope oil and gas production base by creating a new revenue stream in large-scale gas sales; and
- Provide a stable and reliable energy source for many years that will benefit economic development of the region.

62. In recognition of these unique characteristics of an In-State Pipeline option, ENSTAR requested that BRG evaluate alternative ownership and financing structures of this pipeline option. BRG developed three example ownership structures:

a. **Option 2(a).** Traditionally financed, privately owned pipeline.

b. **Option 2(b).** Public-Private Partnership structure, with a private pipeline owner and operator, and a percentage of the project construction costs shouldered by a government sponsor. This is effectively a subsidized structure that can be arranged so that upside economic gains go to the public partner. The level of public investment can vary; BRG modeled an 80% “subsidy” investment.

c. **Option 2(c).** Fully state-owned structure that substitutes a 2% annual return on investment back to the state for State of Alaska and does not carry Ad Valorem tax or a traditional return structure.

3.2.1.3 Option 3 - Kenai LNG

63. Kenai LNG in the context of this study, refers to the concept of retrofitting the Kenai LNG export facility located in Nikiski (owned by Marathon) to be utilized as an LNG import and regasification facility for a broader group of customers than the Kenai refinery as currently proposed by

Marathon.[44] The project would utilize as much of the existing infrastructure as possible, including the pier and the storage tanks, at project initiation. LNG would be imported via an LNG tanker,[45] offloaded, stored in the existing storage tanks, and then vaporized and injected into the Kenai Beluga Pipeline system ("KBPL").

Infrastructure Requirements

64. When the Kenai LNG facility was in active operation, its storage capacity consisted of three tanks with total capacity around 2 BCF. The tanks would be modified as required to fit the new facility arrangement. Since the existing tanks are now more than 50 years old, we suggest that the long-term solution is to site a new storage tank on the facility to replace these aging vessels, with a target date of 2032.

65. Pier upgrades are not expected to be required, however top-side mechanical work on the liquid and vapor lines would be required.

66. New vaporizers (capable of 150 MMcfd sendout capacity) would be installed in the Kenai facility to meet daily send out demands. The design of the plant would allow vaporization scalability. Initial vaporization sendout rates would be discussed and finalized with the Working Group during sequential design phases such that capital deployment is phased responsibly.

67. A custody transfer meter station equipped with gas measurement, and any necessary upgrades to the pipeline connecting the Kenai LNG terminal to KBPL.

68. We note that the infrastructure assumptions are not taking into account the maximum extent of potential investments necessary to bring the facilities to current FERC standards for long-term use, should that be required. These assumptions need to be further examined and developed with participation of the facility owner.

Supply Source and Contracting Strategy

69. Since the current facility owner has filed and gained FERC approval to import LNG for its own gas usage, the contracting strategy for this project has become more complicated than in years past when this project was considered. BRG sees four methods of executing this project:

    a. Joint venture with Marathon for joint investment and LNG sourcing.

    b. Contract with Marathon to provide dry gas supply to utilities.

    c. Purchase the Kenai LNG facility from Marathon with agreement to supply the volumes the Kenai refinery requires.

[44] FERC Docket No. CP19-118-000.

[45] Shipping cost estimates for this and other LNG import options assume average shipping distance equivalent to the distance between Nikiski and Vancouver, and include either seasonal or year-round (depending on annual demand) charter cost assumptions for the requisite number of vessels (up to four ~140,000 cubic meter vessels), associated fuel and incidental expenses, and port fees.

d. Limited use of the facility with floating storage, as suggested by an independent study conducted by CEA and BV, thus only contracting with Marathon for the use of the dock and sufficient land area for regasification.

3.2.1.4 Option 4 -Greenfield Port and Regas

70. A greenfield LNG import terminal is another possible solution to meet the gas needs for the region. This import terminal would contain a pier capable of docking a 3.5-4 BCF LNG tanker which would offload LNG year-round. LNG would be offloaded, stored, and then vaporized when system demand calls for it. Since the Alaska LNG project has been able to site a pier and above ground storage for export purposes, the proposed site for this greenfield import terminal is the same site as that of the Alaska LNG project until further siting search and analysis is performed.

Infrastructure Requirements

71. The proposed pier would be of similar size of the one proposed by the Alaska LNG project, designed to handle LNG cargo ships up to 180,000 m^3 in capacity. The final vessel size will be determined in later phases as scope is narrowed. The chosen vessel will be designed to provide volumes on a year-round basis to the port in the long term. Seasonal deliveries may be appropriate in the near term when shortages between Cook Inlet production and utility demands are not significant.
72. The terminal itself would require approximately 60 acres of land suitable to site a 3.5 BCF storage tank (size to be finalized in further siting and design efforts) along with the necessary spill containment and vaporization equipment.
73. Vaporization capacity for this facility will have capacity finalized in later phases of design efforts but is proposed to scale up to 150 MMcfd at full build out, as currently estimated.
74. A custody transfer meter station equipped with gas measurement, as well as an interconnecting pipeline will be required to deliver volumes from the LNG import terminal to KBPL.

Supply Source and Contracting Strategy

75. The freedom to design the new pier and a new storage tank provides flexibility and opens up additional market possibilities based on acceptable LNG cargo vessel sizes. There are developing projects in British Columbia and Mexico which could provide the contracted LNG volumes for this project. Pricing structure on a $/Mcf basis assumes multi-year contracts using a North American gas index, pipeline toll, liquefaction toll, and marketing premiums.

3.2.1.5 Option 5 – FSRU

76. A Floating Storage and Regasification Unit (FSRU) is a viable LNG import solution to meet gas needs for the region. This option would require the use of a new pier, or an existing dock ("Agrium Pier," currently owned by Nutrien, or other) with modifications to support the year-round docking of large LNG vessels, 140,000 m^3 or larger in size. This solution provides a scalable, but not totally permanent asset to be utilized to supply gas to the region.

Infrastructure Requirements

77. A single large FSRU vessel would be required (3.5 – 4 BCF) for the long-term needs of the region. The vessel would be designed and constructed to be moored permanently at a selected pier that could handle the docking of such a vessel. Onboard the vessel, it is proposed there be enough room to provide a scalable vaporizer arrangement, allowing the flexibility to add necessary equipment to meet increased sendout demands in later years.

78. The pier that is selected for this option must be designed to handle a moored vessel year-round, as even the most efficient seasonal operation can only deliver up to about 37 BCF per year.[46] Seasonal deliveries by an existing FSRU vessel in the market could meet demands in the near term, but would not be a permanent solution as Cook Inlet production continues to decline. Agrium Pier would require substantial work to upgrade the structure to not only handle larger vessels, but reach deeper water at lower risk of freezing. As a result, later stages of analysis should consider siting a new pier for this solution.

79. A high-pressure gas pipeline is required to transport gas from the FSRU vessel, across the pier, and to a custody transfer meter station equipped with gas measurement. Once measured for volume and heat content, an interconnect to KBPL may be required to deliver the volumes to CINGSA or other gas storage. The length of this interconnecting pipeline will be a factor in siting a potential new pier for an FSRU solution.

Supply Source and Contracting Strategy

80. Pending selected or newly installed pier, existing market vessels could be contracted in the near-term and have the potential to be utilized to provide seasonal deliveries, and leave port during the winter months. The new build of an FSRU vessel can be optimized for available supply source and demand profile, and provide the capability to be docked 365-days a year as the demand for LNG volumes grows. British Columbia and Mexico are developing projects that could supply contracted volumes, in addition to spot market volumes. Pricing for this LNG would be based on the NA gas index, pipeline toll, liquefaction toll, and a marketing premium.

3.2.1.6 Option 6 -Barge/Small LNG Carrier

81. Small scale LNG has gained popularity in recent years with companies like Norgas out of Norway[47] supplying single or fleet solutions for LNG transportation and regas needs. A small-scale FSRU would be moored at the end of a pier, take deliveries from vessels smaller than typical LNG carriers (“LNGC”), vaporize the gas on-board, and inject it into a high-pressure gas pipeline where it is transported to a meter station for odorization, gas quality and volume measurement, and then injected into the ENSTAR system. This LNG import option would have sendout scalability as sendout demand grows, but due to smaller on-vessel liquid storage, would also involve increasing the frequency of LNG deliveries to the vessel as the LNG demand grows to cover Cook Inlet shortfalls.

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[46] With an LNGC of 145,000 cubic meters in size, delivering and off-loading to a moored FSRU with re-gas capacity of 300 MMcfd, a seasonal operation from Vancouver may supply the Unmet Gas Demand through 2034.

[47] https://norgascarriers.com/

Infrastructure Requirements

82. A single small scale FSRU vessel would be needed to be moored at the selected site to provide the storage and regas. LNG deliveries would be taken onto the FSRU, stored, and vaporized as needed. These deliveries would quickly scale up as the LNG demand is increased to counteract the Cook Inlet decline in production.

83. A pier, Agrium Pier with modifications or otherwise, will be required to permanently moor the small-scale FSRU vessel. Because these vessels are not as large as a typical LNGC, there is more flexibility in selecting, or constructing, a pier to meet this project's needs.

84. A high-pressure gas pipeline is required to transport gas from the FSRU vessel, across the pier, and to a custody transfer meter station equipped with gas measurement. Once measured for volume and heat content, an interconnect to KBPL may be required to deliver the volumes to CINGSA or other gas storage. The length of this interconnecting pipeline will be a factor in siting a potential new pier for an FSRU solution.

Supply Source and Contracting Strategy

85. British Columbia (Kitimat or Tilbury) are the likely source of this LNG supply and would be long-term contracts due to the limited number of suppliers. Spot market options are likely limited, and would involve re-selling LNG delivered to Asia, or shipping long distances such as from an FSRU on the coast of Peru.

3.2.1.7 Option 7 -Alaska LNG

86. AGDC is advancing the 807 miles, 42-inch pipeline project from the North Slope to Nikiski that is designed to transport about 3.5 BCF/D of natural gas, and export LNG from a new terminal sized at 20 Mtpa (together, the "Alaska LNG" project). This strategic project has reserved more than sufficient capacity for local gas demand and has included local offtakes in its design basis, however there is no lateral pipeline connecting the mainline to Fairbanks in its scope.[48] Therefore, BRG has included a provision for this pipeline in the direct investment portion of the estimate (see Table 3).

87. Alaska LNG has been approved by FERC under Section 3 of the Natural Gas Act as an integrated gas processing, pipeline, and LNG export project. The Biden administration recently re-affirmed its LNG export permit to non-Free Trade Agreement nations.[49] While in possession of significant government and local support, this large project nevertheless faces the challenge of marshalling a ~$43 billion investment and debt package that will require long-term firm LNG supply agreements to secure. Currently in 2023, AGDC is working to secure an initial at-risk FEED

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[48] Alaska LNG project map and description, available at https://alaska-lng.com/

[49] Casey, Jessica, LNG Industry. *Biden Administration authorizes LNG exports from Alaska LNG project*, April 17, 2023, available at https://www.lngindustry.com/liquid-natural-gas/17042023/biden-administration-authorises-lng-exports-from-alaska-lng-project/.

investment of around $150 million for a FEED study.[50] Despite being the lowest-cost alternative if sanctioned at full capacity, Alaska LNG Alaska LNG does not currently have a target FID date and requires multiple years to construct after FID, requiring progress on other alternatives from the Working Group.

3.2.1.8 Option 8 - LNG Truck and/or Rail

88. As another source of LNG, Trucking and Rail transportation from the North Slope was analyzed. Due the lack of established technology, rules, and regulations, in addition to the added layer of logistical barriers, LNG transport by rail was disregarded early on in the evaluation process, and this option became purely trucking from the North Slope. LNG would be produced in Deadhorse, and then trucked by teams of drivers down to the Matanuska-Susitna Valley area where it would be unloaded, stored, and vaporized as demand required.

Infrastructure Requirements

89. Harvest Midstream, an LNG supplier on the North Slope, could expand its planned facility from 150,000 gal/day to 450,000 gal/day by adding two (2) additional trains of LNG production.[51] This production could meet ~13 BCF/yr of total system demand, meaning there would need to be additional sources of gas to meet volume demands very quickly after 2029. As a result, trucking is best looked at as a bridge or partial solution and not a long-term solution to address the declining Cook Inlet production. Understanding this, a virtual pipeline of LNG between the North Slope would involve the following major investments:

- Expanding Harvest Midstream's LNG production facility from initial 150,000 gal/day to 450,000 gal/day.[52]
- A fleet of LNG trucks/trailers to scale with trucking demand, ultimately requiring between 28 and 35 truck deliveries (depending on size of the trailer) on a daily basis to keep up with 450,000 gal/day production.[53]
- A service garage near Fairbanks to act as both a depot to store and repair trucks, as well as a location to switch truck drivers heading north and south.

[50] FY2024 Alaska Governor-Amended Operating Budget Summary, p. 2; at https://omb.alaska.gov/ombfiles/24_budget/PDFs/Corrected_FY2024_Operating_Governor_Amend_Bill_Summary_Spreadsheet_4-18-2023.pdf

[51] Interior Gas Utility, IGU Special Board Meeting Packet, January 17, 2023, pp. 14.19, available at https://www.interiorgas.com/wpdm-package/1-17-2023-igu-special-board-meeting-packet/

[52] Further expansion may be possible but has not been publicly scoped out by the supplier.

[53] While there is sufficient gas on the North Slope to provide supply beyond the 450,000 gal/day, the logistics of having more than this number of trucks on the Dalton and Parks highways appear quite challenging. The operational risks and potential for supply interruptions also must be considered. BRG used 450,000 gal/day as the maximum potential due to these considerations, as well as the cost and contracting information available for this specific option from IGU and Harvest Midstream.

- An LNG Trucking Depot with a 1 BCF storage tank, vaporizers, and gas measurement. Storage tank size and vaporization system sizing is to be finalized in later stages of design to accommodate ENSTAR sendout needs and functional capacity of the operation.

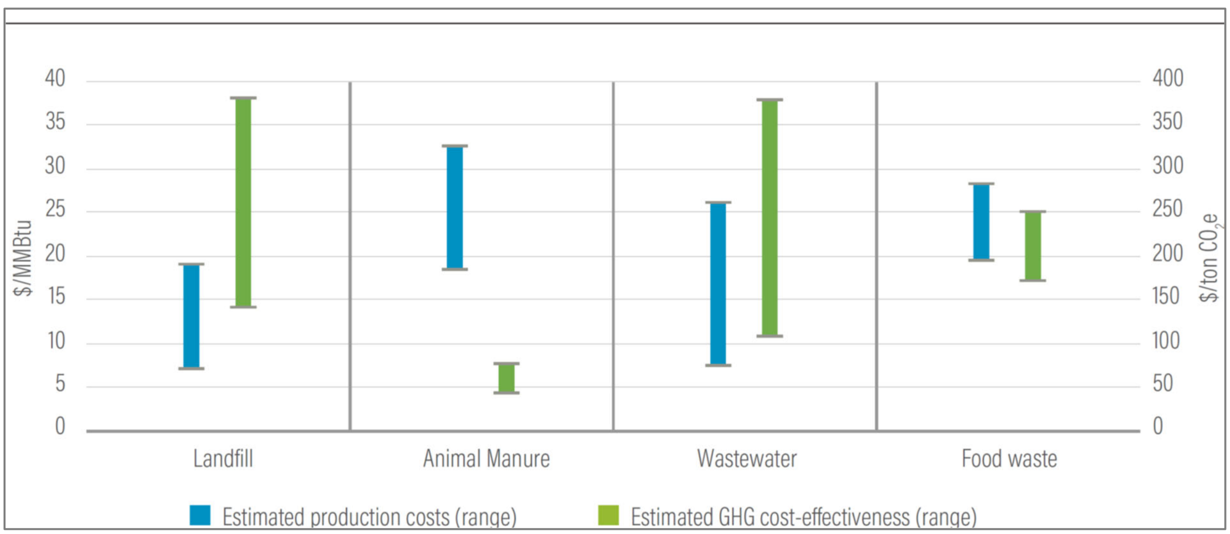
Supply Source and Contracting Strategy

90. Due to the nature of this project requiring extensive investments both on the liquefaction side to produce the LNG, and the LNG trucking depot in Anchorage to store and regas, there would be long-term ~20-year volume commitments on the part of the utilities. Contracts for the volumes would be based on the cost of gas, cost of liquefaction, cost of transportation, and the capital costs associated with the necessary infrastructure investments.

3.2.1.9 Option 9 - RNG

91. Renewable natural gas can be produced by upgrading biogas generated from landfills, wastewater sludge, animal manure, municipal solid waste and other sources. Cost of producing natural gas can vary significantly by source and project as depicted below in Figure 12.[54]

Figure 12: Estimated Project Costs and Greenhouse Gas Emissions



92. BRG identified Landfill and Wastewater biogas as the main potential sources of RNG that could be delivered to the Alaska utilities. The largest landfill[55] in Alaska is the Anchorage Regional Landfill which already collects 4 MMcfd[56] of non-upgraded natural gas, about 2.3 MMcfd[57] flows from Anchorage Landfill Gas to Energy Project that supplies power to Joint Base Elmendorf-

[54] World Resources Institute, *Renewable Natural Gas as a Climate Strategy: Guidance for State Policymakers,* December 17, 2020, https://www.wri.org/research/renewable-natural-gas-climate-strategy-guidance-state-policymakers.

[55] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

[56] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

[57] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

Richardson ("JBER"),[58] and about 2 MMcfd is flared. If the flared gas could be re-used, or if an additional resource in a comparable amount is available at Anchorage Regional Landfill, 2 MMcfd could support production and upgrade to 0.3 BCF/year of pipeline quality natural gas, assuming 50% of the gas is methane and the processing facility runs with 90% efficiency. Palmer Central Landfill currently collects around 0.174 MMcfd[59] of biogas and should also be considered as an additional source but for much smaller quantities.

93. John M. Asplund Wastewater Treatment facility is Alaska's largest wastewater treatment plant with plant capacity of up to 58 million of gallons per day ("MMgal/d"). The process of extracting methane from wastewater requires construction of an anaerobic digestor.[60] Assuming approximately 60 gallons of wastewater per cubic foot of natural gas,[61] John M. Asplund Wastewater Treatment facility could produce up to 0.35 BCF/year of methane. The majority of the remaining treatment facilities in the region treat less than 2.5 MMgal/d of wastewater, making the economics of producing RNG from such facilities unfavorable.

94. It is likely that up to around 1 BCF/year of renewable natural gas could be produced in Alaska from various across Southcentral Alaska and the Railbelt. There is significant heterogeneity in the cost of supply across different projects and sources of renewable natural gas. Further detailed assessment is needed to quantify the cost of producing natural gas from specific source in Alaska. The higher end of the cost ranges provided in Figure 12 for wastewater and landfill derived RNG development are likely in Alaska due to the length of supply chain and generally higher construction costs.

3.2.1.10 Hydrogen

95. Hydrogen can be produced from multiple sources including natural gas, renewable power sources, nuclear power, coal, as well as biomass. Hydrogen produced from renewable power sources is generally referred to as green hydrogen. BRG assessed potential for wind based green hydrogen development in Cook Inlet. BRG did not estimate the cost of supplying hydrogen from natural gas because natural gas can be used directly in the ENSTAR natural gas system. Furthermore, production of natural gas-based hydrogen would require sufficient and inexpensive gas supply which is unlikely to be available in Cook Inlet unless a viable alternative to Cook Inlet sourced gas is found.

96. Cost of power is the main cost input associated with green hydrogen production. On October 10, 2011 RCA approved a 25-year PPA between Chugach Electric Association and CIRI to supply power from Fire Island Wind facility located in Cook Inlet. Under the supply agreement Chugach

[58] Municipality of Anchorage, *Anchorage Landfill Gas to Energy Project Details,* https://www.muni.org/departments/sws/pages/anchlandfillgastoenergyprj.aspx.

[59] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

[60] Vutai, V., Cissy Ma, and M. Lu, The Role of Anaerobic Digestion in Wastewater Management, EM Magazine, Air and Waste Management Association, Pittsburgh, PA., 2016.

[61] Lacey, Pamela A., *Developments in Renewable Natural Gas: The Promise of RNG*, American Gas Association, October 26, 2017, p. 8, available at https://www.epa.gov/sites/default/files/2017-11/documents/27.lacey_2017aiw.pdf.

electric pays a fixed price of $97 per megawatt hour.[62] In 2023 electric power rates for large customers ranged between $90 to $137 per megawatt.[63] However, future clean power rates for generation of hydrogen are expected to fall, as the costs of technology for both new solar and wind power generation have decreased globally by 88% and 68% respectively in the past decade.[64] In Alaska, this is evidenced by a more recent small (6 MW) solar power contract held by MEA at $67/MWh,[65] although the project is not anywhere near the size necessary for utility-scale hydrogen generation.

97. Other major cost items include capital expenditures to acquire an electrolyzer facility, cost of acquiring or leasing land parcel of sufficient size to accommodate electrolyzer infrastructure, access to and processing costs of fresh water required for hydrogen generation, operating and maintenance costs as well as onsite and offsite costs that include hydrogen distribution and storage costs, and potential upgrades to the ENSTAR system to accommodate hydrogen development.

98. The Inflation Reduction Act of 2022 introduced tax credits for qualified clean hydrogen facilities.[66] Facilities that begin construction before January 1, 2033, produce less than 0.45 kilograms of CO2 equivalent lifecycle emissions, and meet prevailing wage and apprenticeship requirements can qualify for a tax credit of up to $3/kg for a period of 10 years. The tax credit is viewed as a significant subsidy by industry participants.[67]

99. To assess the viability of hydrogen development in Southcentral Alaska, BRG assumed that the tax credit, if efficiently monetized, could be sufficient to cover both capital and operating costs of an electrolyzer facility and all associated infrastructure costs, other than the cost of power. Assuming power price in the range of $70-80/MW, a high efficiency electrolyzer facility that requires 53 kWh[68] per kg of hydrogen, and a lower heating value of 51,585 btu per pound of hydrogen the cost of delivered hydrogen would exceed $32/MMBtu.

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[62] Chugach Electric, *Fire Island Wind- Power Purchase Agreement*, https://www.chugachelectric.com/about-us/regulatory-affairs/fire-island-wind.

[63] Chugach Electric, *South District Rate Information*, April 1, 2023, https://www.chugachelectric.com/member-services/billing-payments/rate-information-south-district; Matanuska Electric Association, *Schedule of Rates for Q2 2023*, https://www.mea.coop/co-op-benefits/current-rates; Golden Valley Electric Assn, *Rates,* March 1, 2023, https://www.gvea.com/services/rates/; Homer Electric Association, *Rate Schedule*, April 1, 2023, https://www.homerelectric.com/member-services/my-bill/rates/.

[64] IRENA, Renewable Power Generation Costs in 2021, p. 15, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Power_Generation_Costs_2021.pdf?rev=34c22a4b244d434da0accde7de7c73d8

[65] RCA, TA535-18; summarized at https://aws.state.ak.us/OnlinePublicNotices/Notices/View.aspx?id=205057

[66] 26 U.S. Code §45V – Credit for production of clean hydrogen. *See* White House, Building a clean energy economy: A guidebook to the inflation reduction act's investments in clean energy and climate action, p. 75, available at https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.

[67] Bloomberg Tax, *The New Clean Hydrogen Production Tax Credit, Explained*, November 23, 2022, https://news.bloombergtax.com/daily-tax-report/the-new-clean-hydrogen-production-tax-credit-explained.

[68] US Department of Energy, HydroGen, *High Efficiency PEM Water Electrolysis Enabled by Advanced Catalysts, Membranes and Processes*, p. 3, April 30, 2019, https://www.hydrogen.energy.gov/pdfs/review19/p155_ayers_2019_o.pdf.

100. It is important to keep in mind that additional clean power generation capacity is more efficiently used first to replace thermal power generation, before expending additional resources to turn it into a gas in a market that is already experiencing a power fuel shortage. However, there may be synergistic systems of hydrogen production during times of low power demand, once sufficient renewable generation capacity exists.

3.2.2 Cost of Supply Assumptions

101. Due to the screening level of this Phase I Assessment, the costs of each project option were evaluated at a very preliminary level, frequently without the ability to examine physical characteristics of existing infrastructure. Where possible, available, and of a higher quality than would be reasonable to estimate for this assessment, third-party estimates were used, such as those developed by specific project sponsors. However, the estimates were evaluated for reasonableness and completeness with similar projects, and brought to the same $2023 basis at a high level.[69] Table 5 below summarizes the sources of each major cost assumption for the evaluated options.

Table 5: Basis of Cost of Supply Assumptions

#	Option	Cost of Gas	CAPEX	OPEX
1	Cook Inlet Gas	BRG, based on 2018 and 2023 ADNR Cook Inlet Reserves studies	BRG / Public Sources	NA
2	In-State Pipeline	AGDC (Fixed w/escalator)	AGDC, inflated at CPI, omitting GTP, adding pipeline from Pt Thomson to Deadhorse	AGDC as % of Capex
3	Kenai LNG	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
4	Greenfield Port and Regas	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
5	FSRU	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
6	Barge / Small LNG Carrier	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
7	Alaska LNG	AGDC (Fixed w/escalator)	AGDC	NA
8	LNG Truck and/or Rail	IGU (Fixed w/escalator)	Cornerstone/BRG	IGU/Cornerstone/BRG
9	RNG	BRG / Public sources	BRG / Public sources	BRG / Public sources
10	Hydrogen (green)	BRG / Public sources	BRG / Public sources	BRG / Public sources

[69] Without examining component-specific inflation.

102. In order to develop consistent cost of supply assumptions for all options, we assumed that the costs of investing in each project would be amortized over consistent Unmet Gas Demand, levelized using common midstream capital structure and discount rate assumptions for a 20-year period, and then converted back to $2023 values using inflation assumptions.

103. The capital structure assumptions used for all midstream and shipping infrastructure investments were 60% debt, 40% equity, with 4.6% after-tax cost of debt (BBB rating), and 12% cost of equity. We applied inflation using historic 10-year CPI for All Urban Consumers, PPI for Oil and Gas Extraction, and PPI for Oil and Gas Field Machinery and Equipment Manufacturing indices, as appropriate, to adjust historical estimates. For long-term inflation, we assumed 2% average.[70]

104. The resulting cost of supply estimate range, using High and Low Working Group demand forecast as a variable of the range for midstream costs are presented in Table 6 (for private project options) and Table 7 (for government participation options) below.

Table 6: Private Project Options

					Cost of Supply		
Option		Timeline from decision YE2023	Capital Investment	Supply Volume	Gas	Midstream	Total
		years	$ mm	BCF/year	$/Mcf	$/Mcf	$/Mcf
1	Cook Inlet Gas	3 - 4	up to $1500 - $2000	up to ~23	$9.3 - $25.5	Included	$9.3 - $25.5
2 (a)	In-State Pipeline (Private)	6 - 7	~ $8,790	up to 105	$1.3 – $2.6	$26.8 – $34.2	$28.1 - $37.0
3	Kenai LNG	4 - 5	$768	up to 55	$8.6 - $8.9	$3.4 - $4.7	$12.0 - $13.6
4	Greenfield Port and Regas	6 - 7	$876	up to 55	$8.6 - $8.9	$4.0 - $5.3	$12.6 - $14.2
5	FSRU - Own/Lease	4 - 6	$698	up to 55	$8.6 - $8.9	$3.6 - $5.0	$12.2 - $13.9
6	Barge / Small LNG Carrier	4 - 5	$563	up to 25	$8.6 - $8.9	$13 - $14	$21.6 - $23.0
7	Alaska LNG	7 - 8	~$43,000	up to 183	$1.3 – $2.6	$3.1	$4.4 - $5.8
8	LNG Truck and/or Rail	3 - 4	$321	~9	$2.50	$22.5 - $29.5	$25 - $32

[70] Long-term inflation is used to estimate future annual capital and operating costs of each project, as well as for adjusting future expected tariffs and prices to $2023. Since the valuation period of all projects is about 27 years, the use of standard long-term inflation factor is appropriate. All Capex and Cost of Supply estimates are expressed in $2023 for consistency, and actual project metrics such as capital investment at the time of expenditure, or contract gas prices, will be impacted by actual inflation to the extent it differs from this assumption.

Option		Timeline from decision YE2023	Capital Investment	Supply Volume	Cost of Supply: Gas	Cost of Supply: Midstream	Cost of Supply: Total
		years	$ mm	BCF/year	$/Mcf	$/Mcf	$/Mcf
9	Renewable Natural Gas	Unknown	n/a	~1	~$25	Included	~$25
10	Hydrogen (green)	12+	unknown	n/a	n/a	n/a	$>32

Table 7: State Participation Options

Option		Timeline from decision YE2023	Capital Investment	Supply Volume	Cost of Supply: Gas	Cost of Supply: Midstream	Cost of Supply: Total
		years	$ mm	BCF/year	$/Mcf	$/Mcf	$/Mcf
2 (b)	In-State Pipeline (Subsidized 80%)	6 - 7	~ $8,790	up to 105	$1.3 – $2.6	$7.8 - $9.9	$9.2 - $12.6
2 (c)	In-State Pipeline (State Owned)	6 - 7	~ $8,790	up to 105	$1.3 – $2.6	$5.9 – $7.4	$7.3 - $10.0
4 (b)	Greenfield Port and Regas (Subsidized 80%)	6 - 7	$876	up to 55	$8.6 - $8.9	$2.3 - $3.3	$10.9 - $12.2
4 (c)	Greenfield Port and Regas (State Owned)	6 - 7	$876	up to 55	$8.6 - $8.9	$2.2 - $3.1	$10.8 - $12.0

3.2.3 LNGC Assumptions

105. Any LNGC or barge entering Alaska waters must obtain approval of the U.S. Coast Guard ("USCG"). USCG regulates LNGCs' structural steel requirements via 46 CFR 154.176(b)(1)(iii), which requires that "longitudinal contiguous hull structure of a vessel having cargo containment systems with secondary barriers must be designed for Alaskan waters the ambient cold condition of -29 °C (-20 °F)."[71] This regulation applies to all Alaska waters from the North Slope to Ketchikan, without regard for local conditions.

[71] 46 CFR 154.176(b)(1)(iii)(A), Longitudinal contiguous hull structure, up to date as of May 19, 2023; 46 CFR 154.172(c), Contiguous steel hull structure, up to date as of May 19, 2023; 46 CFR 154.32(c), Equivalents, up to date as of May 19, 2023; US Department of Energy, *LNG Annual Report 2015*, Office of Fossil Energy; US Department of Energy, *LNG Annual Report 2014*, Office of Fossil Energy.

106. Among other requirements, this design temperature leads to the requirement for "low-temperature" carbon steel for vessels designed to temperature of -25 °C (- 13 °F). In order to comply with 46 CFR 154.172 (b), vessels need to be constructed using "type E" steel. [72] Given that the Coast Guard regulations do not apply in other commonly visited cold-weather LNG ports, most vessel owners do not select to employ this type of steel in the manufacturing of their ships. There are only two bespoke 89,900 m^3 carriers in the market that were built for ConocoPhillips in 1992-1993. [73] These vessels, Seapeak Polar and Seapeak Arctic, are now owned by Seascape, with one of them offered for demolition sale earlier in 2023.[74]

107. A regular LNGC could be considered compliant with the regulation on an "equivalency argument," as per 46 CFR 154.32 "equivalent or greater protection for the purpose of safety."[75] For example, ConocoPhillips brought LNGC Excel to the Kenai LNG plant in the past for summer cargo shipping between April and October.[76]

108. Based on these standards and history, we are making the assumption that a standard LNGC or FSRU in good condition could be approved to operate in Alaska approximately during the summer months, but a newbuild LNGC or FSRU would be required to operate year-round, given the advanced age and scarcity of the two existing tankers that were constructed specifically for Alaska operations.

109. Even though chartering an LNGC or FSRU for seasonal use is a possible option, BRG has not evaluated availability of specific vessels. Based on BRG's research, there are currently 17 active FSRUs which are under 150,000 m^3.[77] Charter rates for FSRUs and LNGCs have experienced significant recent volatility.[78] This option needs to be approached with the FSRU owners and suppliers at the opportune time when the Working Group is ready to commit to this path.

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[72] 46 CFR 154.172(b), up to date as of 5/19/2023.

[73] ConocoPhillips, *The History of Cook Inlet,* https://www.conocophillipsalaska.com/ea/cookinlettimeline/.

[74] Seapeak, Our fleet, https://www.seapeak.com/our-capabilities/our-fleet/. See also TradeWinds, *Thirty-year-old Seapeak LNG carrier offered for demolition sale*, January 11, 2023, https://www.tradewindsnews.com/gas/thirty-year-old-seapeak-lng-carrier-offered-for-demolition-sale/2-1-1385599.

[75] 46 CFR 154.32, up to date as of 5/19/2023.

[76] US Department of Energy, Vessel-Borne Export of Domestically Produced Liquefied Natural Gas, 2014 and 2015.

[77] BRG internal research; Kpler Database.

[78] Dempsey, H., *Europe battles to secure specialized ships to boost LNG imports*, Financial Times, March 27, 2022, https://www.ft.com/content/bc5f79a6-729e-47ff-bf46-cb23c460fa6f; Chambers, S., *LNG carrier rates on a charge*, Splash 247, September 14, 2022, https://splash247.com/lng-carrier-rates-on-a-charge/; Miller, G., *Price of LNG goes stratospheric. Will LNG shipping rates follow?*, Freight Waves, August 24, 2022, https://www.freightwaves.com/news/price-of-natural-gas-goes-stratospheric-will-lng-shipping-rates-be-next.

4 OPTION SELECTION

110. In this chapter we review the process that BRG and Working Group undertook to select the most viable options among the alternatives that should progress through the next phase of the project.

4.1 Option Scoring Methodology

111. BRG and the Working Group collaboratively developed a scoring methodology that prioritized certain characteristics of each project option and assigned a scoring weight between 1 and 10 according to that priority.[79] While not every member of the Working Group applied the same priority to each selection criteria, the overall results had significant consistency. BRG proposed a consistent priority ranking of selection criteria after review and discussion with the Working Group.

112. We converted the scoring weights to multiplier values, according to the Ratio Method.[80] These multipliers are used to multiply the scores for each project option in each criteria, and then the resulting products are summed together to show a project score for each option up to five (5), the highest possible value.

4.2 Option Scoring Process

113. The table below shows the criteria prioritization results and the final Ratio Method score multipliers.

[79] ADNR and AEA did not submit individual priority rankings, as they participated in an advisory and informational capacity and thus did not participate in the ranking or scoring. *See* Roszkowska, E., *Rank Ordering Criteria Weighting Methods – A Comparative Overview,* Optimum. Studia Ekonomiczne, Nr 5 (65), 2013, available at https://pdfs.semanticscholar.org/f983/e8c4eb7d7c30694dd72c5849dd6fee8a5c79.pdf.

[80] Roszkowska, Ewa, *Rank Ordering Criteria Weighting Methods – A Comparative Overview,* Optimum Studia Ekonomiczne, Issue 65, No. 5, p. 7, 2013, section 4.2.

Table 8: Option Scoring Criteria Summary – Working Group Input and Final Results

Priority	Scoring Criteria	ENSTAR	Chugach	MEA	GVEA	HEA	IGU	BRG Recommendation (10 = Highest Weight)	Ratio Method Score Multiplier
1	Schedule Risk	10	9	10	6	10	9	**10**	**0.18**
2	Reliability of supply during operations	9	10	9	10	5	10	**9**	**0.16**
3	Delivered cost per Mcf/MMBtu	8	8	6	9	9	8	**8**	**0.14**
4	Flexibility	7	5	7	7	7	7	**7**	**0.12**
5	Project Complexity and Integration	5	4	8	2	5	5	**6**	**0.11**
6	Permitting	6	3	4	1	6	3	**5**	**0.09**
7	Environmental Impact	4	6	2	3	6	2	**4**	**0.07**
8	Size of direct investment required by the utilities (CAPEX)	3	2	5	8	8	6	**3**	**0.05**
9	Local economic impact (jobs and revenues)	2	1	1	5	4	4	**3**	**0.05**
10	Carbon efficiency / Climate change impacts	1	7	3	4	6	1	**2**	**0.04**

114. For each Scoring Criteria, BRG in consultation with the Working Group developed a scale of one (1) or zero (0) to 5, and a description of what each score represented in valuing the options, to ensure consistent results. The summary of the scores is presented below in Table 9.

Table 9: Project Option Scores - What Each Value Means

Priority	Scoring Criteria	Score
1	Schedule Risk	5 = Meets contract shortfall by 2026 and volume shortfall by 2029 4 = Meets contract shortfall by 2026 but provides no long-term solution 3 = Meets volume shortfall by 2029 with other options to supplement 2 = Meets volume shortfall by 2029 but precludes other options 1 = May not meet volume shortfall by 2029 and precludes other options 0 = Provides immaterial supply, or utility demand has no ability to affect the sanction of this option

Priority	Scoring Criteria	Score
2	Reliability of supply during operations	5 = Project uses proven technology, experienced providers, and is local to the service area 4 = Project uses proven technology but requires investment remote from service area 3 = Project uses mostly proven technology and relies on new market entrants 2 = Project uses novel technology deployed by experienced suppliers local to the area 1 = Project relies on new technology, providers, and geographic challenges
3	Delivered cost per Mcf/MMBtu	5 = < \$10.50 per Mcf 4 = \$10.50 - \$14.00 per Mcf 3 = \$14 - \$20 per Mcf 2 = \$20 - \$30 per Mcf 1 = > \$30 per Mcf
4	Flexibility	5 = Storage and gas supply can be increased yearly with no cost or efficiency penalties 4 = Storage and gas supply can be increased in multi-year phases 3 = Storage and gas supply can be ramped up according to a plan but requires substantial upfront investment 2 = Project can be implemented in two (2) phases 1 = Firm daily supply commitment, infrequently adjusted.
5	Project Complexity and Integration	5 = Pipeline system impacts only 4 = Pipeline and Utility Group system impacts including storage 3 = Third party participation required (producers or importers) 2 = Multiple third parties involved 1 = New large diameter pipeline
6	Permitting	5 = Municipal permitting only 4 = State agency permits required 3 = State/Federal permits with offshore impact 2 = FERC permit required 1 = FERC permit required with offshore impact
7	Environmental Impact	5 = Project has minimal or insignificant environmental impact and relies on previously developed infrastructure 4 = Project has modest onshore environmental impact that is easily mitigated 3 = Project has significant onshore environmental impact that will require significant expense to mitigate 2 = Project has modest onshore and offshore environmental impact 1 = Project has significant onshore and offshore environmental impact

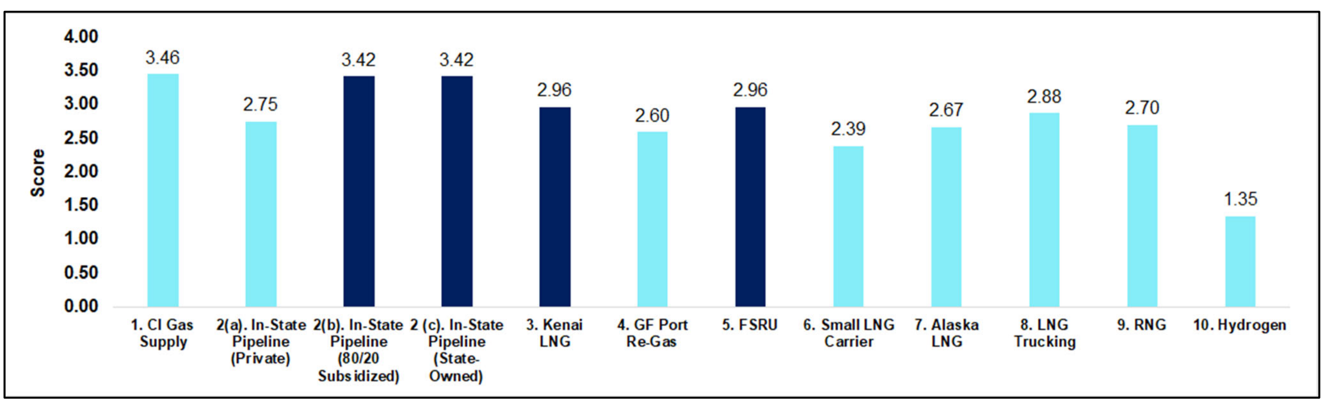
Priority	Scoring Criteria	Score
8	Size of direct investment required by the utilities (CAPEX)	5 =< $300MM 4 = $301 - $600MM 3 = $601-$900MM 4 = $901MM - 1.2B 1 = > $1.2B
9	Local economic impact (jobs and revenues)	5 = > 80% jobs and revenues created are in Alaska 4 = >60 - 80% jobs and revenues created are in Alaska 3 = >40 - 60% jobs and revenues created are in Alaska 2 = >20 - 40% jobs and revenues created are in Alaska 1 = < 20% jobs and revenues created are in Alaska
10	Carbon efficiency / Climate change impacts	5 = Involves a low-carbon fuel or renewable power solution 4 = Local gas production 3 = Gas liquefaction and short-distance transportation 2 = Gas liquefaction and long-distance transportation 1 = Reliance on high-carbon fuels

4.3 Results of Option Scoring Exercise

115. BRG conducted an engineering and commercial evaluation to assign scores to each of the project options. The scores were based on a screening-level evaluation of each option's scope characteristics as described above in this report, including cost, permitting, and schedule constraints. BRG built a cost of supply model in order to evaluate the 20-year levelized equivalent cost of service for each option.

116. The resulting score of all project options and sub-options related to the financing and sponsorship of the In-State Pipeline are presented in Figure 13.

Figure 13: Option Score Summary



117. Based on the scoring results, the Working Group is further evaluating the following options in addition to Cook Inlet Gas Supply[81]:

118. **In-State Pipeline**. In order to achieve the benefits of this option, a decision to subsidize this project needs to be made in an expeditious manner. Given the projected time required to construct a long-distance pipeline across Alaska, it is likely that alternative supply is still necessary to bridge the time to when the pipeline gas becomes available. While an In-State Pipeline project has many benefits, including development of North slope gas with many years of supply security, state royalties, and ability to provide gas to communities along the pipeline route, In-State Pipeline carries prohibitive costs if developed solely for the Working Group utility demand. Reconfiguring the project so that state ownership or an investment decision can be made on the merits of the project for Alaska demand and its economic benefits, rather than depending on large export LNG buyer commitments, would be a change in the strategy of the project and its current owner, Alaska Gasline Development Corporation ("AGDC"). We recognize this as a policy decision outside the scope of this report.

119. **Kenai LNG**. Retrofitting the former Nikiski LNG export facility currently owned by Marathon presents an opportunity to use a brownfield facility with existing pipeline connections to the main ENSTAR system, existing dock, and potentially existing LNG storage tanks. This option provides important advantages of shortening the time to project start-up and potentially lowering costs of LNG import. However, the old age of the facility and the size and condition of the dock and tanks (currently in warm status) present their own risks and challenges related to permitting and potential costs. In addition, Marathon's stated goal to employ the site as a small import facility for Kenai Refinery's own gas needs presents a potential regulatory and operational conflict. This option should not be discounted at this stage due to its timing advantages, provided that good-faith negotiations with the facility owner begin expeditiously.

120. **FSRU**. Importing LNG using an FSRU as storage and regas provides a significant project schedule advantage. To the extent a suitable chartered FSRU vessel can be secured in the short term, this option has the shortest lead time and lowest risk of securing necessary supply of all options reviewed. The key risks to the schedule of this option are availability of cold climate appropriate FSRUs of the right capacity (i.e. small enough to utilize existing docks), and the availability and suitability of either the Agrium Pier (owned by Nutrien) or Marathon dock.

121. These top options, with scores by individual prioritized criteria, are presented in Table 10 below.

[81] See recommendations on Cook Inlet Gas Supply option in Sections 1.3, 16, and 3.2.1.1.

Table 10. Top Scoring Project Options in Phase I

		1 = Low Score, 5 = High Score			
Prior	**Scoring Criteria**	**2(B). In-State Pipeline (80/20 Subsidized)**	**2 (c). In-State Pipeline (State-Owned)(1)**	**3. Kenai LNG**	**5. FSRU**
1	Schedule Risk	1	1	3	3
2	Reliability of supply during operations	5	5	4	4
3	Delivered cost per Mcf/MMBtu	5	5	4	4
4	Flexibility	3	3	2	3
5	Project Complexity and Integration	2	2	2	3
6	Permitting	4	4	2	1
7	Environmental Impact	3	3	4	2
8	Size of direct investment required by the utilities (CAPEX)	5	5	3	4
9	Local economic impact (jobs and revenues)	4	4	2	1
10	Carbon efficiency / Climate change impacts	4	4	2	2
	TOTAL WEIGHTED SCORE (Scale 0 to 5)	**3.42**	**3.42**	**2.96**	**2.96**

5 MARKET, PRICE VOLATILITY, AND RISK ANALYSIS

122. In this chapter, we review the current LNG market conditions and outlook, including the global and North American liquefaction capacities. We also analyze the volatility of energy commodity markets to which new LNG supply to Alaska could be indexed.

5.1 LNG Market Environment and Current Outlook

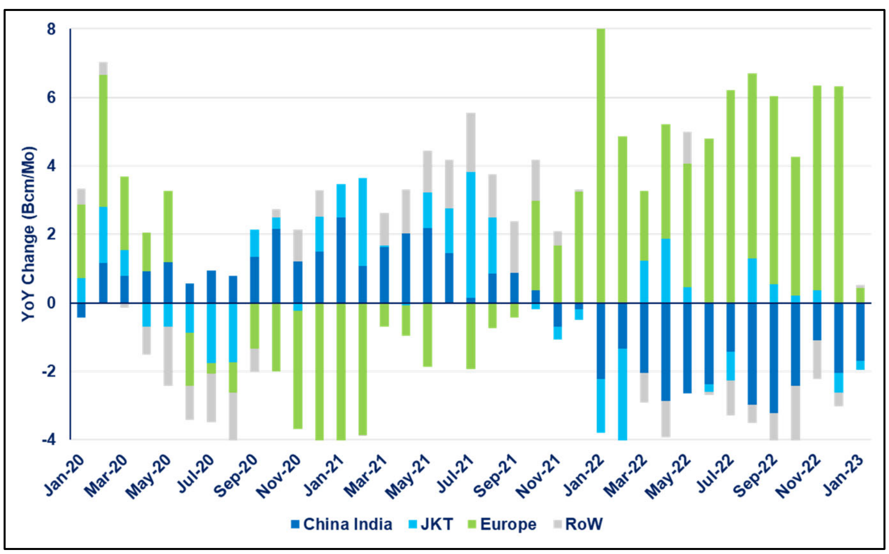
5.1.1 LNG Market Developments

123. LNG market conditions have experienced major changes in the past few years, moving from low prices during the oversupply period in the mid-2020s to extreme high prices in 2021 and 2022.

124. Recent history has indicated a dynamic LNG flow pattern. Global LNG demand dropped sharply in 2020 and as a result, suppliers and importers offloaded their mounting surplus into Europe. Amid economic recovery from the pandemic and demand growth in China, global markets tightened, and LNG supplies shifted towards higher-priced Asian markets starting in mid-2020, as seen in Figure 14.

125. Thereafter, from 2Q 2021, Russia materially reduced its pipeline exports to Europe, and subsequently European nations sought to replace Russian pipeline gas in large part with LNG imports. This resulted in a sharp rise in European demand and correspondingly, higher regional prices pulled LNG supplies away from Asia and into Europe.

Figure 14: Historical LNG Import Movements since January 2020[82]



[82] BRG Analysis of Kpler data.

5.1.2 LNG Market Demand and Supply Outlook

126. The Global LNG market is expected to remain tight in the next few years. Europe is continuing to shift its reliance from Russian gas to LNG following the energy crisis in the second half of 2021 and Russia's invasion of Ukraine. Global LNG demand could reach up to 444 million tonnes[83] in 2026, an increase of 18% from 2021.[84]

127. The favorable market conditions of 2022 did not translate into FIDs on LNG liquefaction projects, with just under 5 trillion cubic feet per year of new capacity globally (excluding North America) that is under construction.

128. Based on BNEF LNG outlook, China, South Asia and Southeast Asia could see LNG imports climb, especially as coal-to-gas switching initiatives continue in China, but growth may be restricted by increased spot LNG prices. Northwest Europe and Italy are slated to see the largest jump in LNG imports, as their LNG demand increases by 36 million tonnes by 2026 compared to 2021. Japan, Korea, Taiwan (JKT) region is the only major market forecast to see a dip in LNG demand due to higher nuclear, renewables and coal generation in Japan and a lower gas demand for power in South Korea.[85]

129. New supply projects are expected to ramp up in the coming years, particularly in the US. Global supply is forecasted to increase to 460 million tonnes in 2026,[86] an almost 20% rise from 2021.[87]

130. With the tight supply expected until 2026, prices are expected to maintain at elevated levels compared to their pre-Covid levels.[88]

5.2 Historic Gas and LNG Price Volatility Analysis

131. Global gas and LNG markets have been characterized by extreme volatility since second half of 2021, largely due to restrained capital expenditure since 2016, buoyant post-pandemic economic conditions, and Russia's invasion of Ukraine in early 2022, which fostered intense global competition for LNG supply to replace Russian pipeline imports. The volatility of energy

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[83] 21.3 trillion cubic feet, using a conversion factor of 1 million tonnes of LNG to 48.028 billion cubic feet of gas from BP Statistical Review of World Energy, Approximate conversion factors, July 2021, p. 2.

[84] Bloomberg, *Global LNG market outlook 2022-26*, June 29, 2022, Global LNG balance- slide 3, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/.

[85] Bloomberg, *Global LNG market outlook 2022-26*, June 29, 2022, Global LNG balance- slides 3-4, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/.

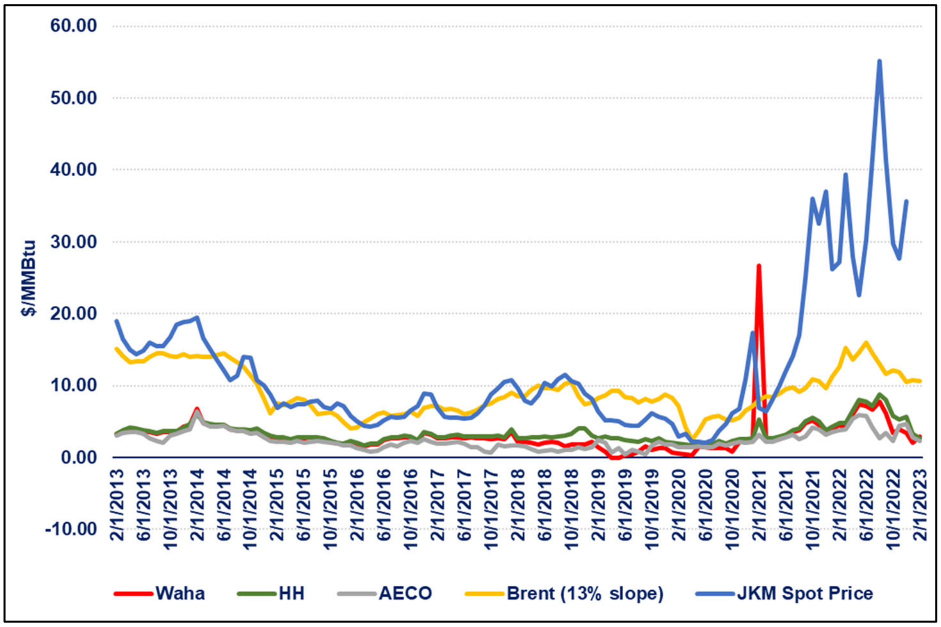
[86] 22.1 trillion cubic feet, using a conversion factor of 1 million tonnes of LNG to 48.028 billion cubic feet of gas from BP Statistical Review of World Energy, Approximate conversion factors, July 2021, p. 2.

[87] Bloomberg, *Global LNG market outlook 2022-26,* June 29, 2022, Outlook overview- slide 1, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/. Note that supply generally exceeds demand due to average utilization of less than 100% of installed capacity.

[88] Bloomberg, *Global LNG market outlook 2022-26*, June 29, 2022, Outlook overview- slide 1, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/.

commodity markets to which LNG supply to the Alaskan project could feasibly be indexed is illustrated in Figure 15 below.[89]

Figure 15: Potential LNG Price Indices: Historical Trends[90]



132. Prices at North American hubs also increased – albeit to a lesser extent – partly due to surging LNG export demand. Average monthly prices at Henry Hub, Waha, and AECO reached their highest levels in over a decade last year. However, prices at North American hubs have since moderated substantially, and there is little to suggest that the multi-year highs of 2022 are likely to recur with any frequency.

133. Nevertheless, LNG and gas price volatility remains elevated by historical standards. This is demonstrated in Table 11, which presents annualized volatility, a measure of how LNG prices fluctuate over a given period, in each of the markets in Figure 15 since 2013. Uncertainty in market conditions or events that affect natural gas supply and demand tend to result in higher price volatility.

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[89] Unlike AECO, Henry Hub ("HH"), and Brent crude oil prices, Platts' JKM does not represent a traded market or hub. Rather, it is a price assessment, which is compiled daily on the basis of voluntary reporting of transactions by market participants

[90] Price data from Platts' and S&P Global Capital IQ.

Table 11: Annualized Volatility of Potential LNG Price Indices[91]

Index/Hub	Annualized Volatility 2013-2016	Annualized Volatility 2017-2020	Annualized Volatility 2021-2023
Brent Crude Oil	24%	27%	37%
Henry Hub	50%	58%	106%
Waha Hub	73%	513%	362%
JKM	11%	26%	116%
AECO	62%	473%	277%

134. JKM price volatility has spiked since late 2021 due to disruption to and then full cessation of Russian supply to Europe, prompting intense global competition for spot LNG cargoes. Competition has moderated in recent months, and JKM prices have stabilized, but volatility remains high. In contrast to JKM, volatility at AECO and Waha is in large part a function of low prices in recent years – resulting from constraints on takeaway capacity and local pipeline bottlenecks – rather than demand spikes and reduced global gas availability. The average price of each indexation option since 2013 is presented in Table 12. [92]

Table 12: Average Historical Prices of Potential LNG Price Indices

Index/Hub	Average Price ($/MMBtu) 2013-2016	Average Price ($/MMBtu) 2017-2020	Average Price ($/MMBtu) 2021-2023
Brent Crude Oil	14.55	10.90	14.76
JKM	12.29	7.38	26.14
Henry Hub	3.55	2.88	5.09
Waha Hub	3.43	1.77	5.45
AECO	3.05	1.42	3.51

5.2.1 Potential LNG Price Indices: Price-Volatility Trade-Off

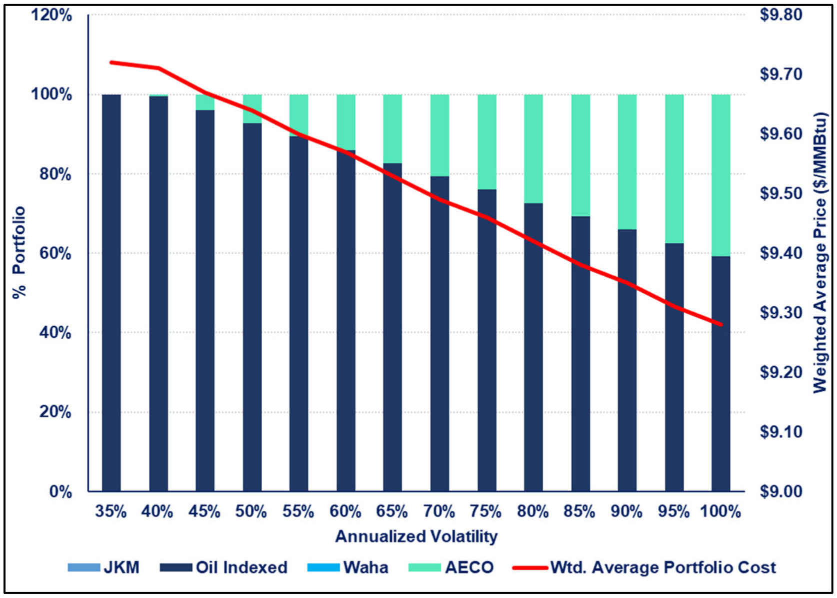
135. Current price projections indicate a modest trade-off between price and volatility with respect to the potential LNG price indices. To evaluate the scale of this trade-off, we use numerical optimization software to solve for the index – or combination of indices – that yields the lowest-cost LNG import portfolio (displayed on the secondary y-axis) available for each 5% increase in

[91] BRG analysis of Platts' and S&P Global Capital IQ price data. Annualized volatility is calculated by taking the standard deviation of the daily price changes over the course of each year and multiplying the result by the square root of the number of trading days in each year.

[92] Note that Waha, HH, and AECO represent only a portion of LNG FOB contract price, as those indices are paired with additional gas transportation and liquefaction fees before shipping, on the order of $4-6 per MMBtu in addition to the index price. JKM Spot Price generally includes full LNG price including shipping to the market hub, and Brent-based LNG prices may or may not include shipping, depending on contract.

annualized volatility (displayed on the x-axis) between 2024–2034. The least volatile potential price index considered is Brent crude oil, with an annualized volatility of 35% since 2013. The results of this analysis are displayed in Figure 16.

Figure 16: Expected Volatility & Average Price (FOB) of Potential Supply Options (2024-34)[93]



136. Assuming a slope of 14% (expressed as a percentage of crude oil prices in $/bbl), an LNG import portfolio fully indexed to Brent crude – the least volatile potential index – is expected to cost just under $9.80/MMBtu over the 2024-2034 time period. This is approximately $1/MMBtu higher than an equivalent portfolio indexed entirely to AECO hub (after accounting for estimated liquefaction costs and marketing fees). Perhaps unsurprisingly, JKM is likely to present the highest potential risks by both metrics, and does not feature in the optimal indexation mix.

5.3 LNG Market Sourcing Strategy

137. The high level of uncertainty that still exists in the design and schedule of any LNG import project makes it too early to engage in LNG contracting other than as part of very early-stage discussions with potential suppliers. Additionally, the annual growth in Unmet Gas Demand and the overall low volumes on the scale of the global LNG market make it a challenge to create the right shape of a multi-year contract. However, ability to plan and use in-ground gas storage can mitigate the issue of instability of demand by allowing to store gas in early low-demand years of shortage.

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[93] BRG analysis using price projections developed for the Cook Inlet Gas Supply Project options analysis. Historical annualized volatility calculated based on price data from Platts' and S&P Global Capital IQ. Projected prices include assumed liquefaction & marketing costs.

138. As we reviewed above, Alaska's best matches in the LNG market for suppliers are the projects on West Coast of Mexico and Canada that are currently under construction or in pre-FID stages. Capacity associated with those projects has largely been sold through 2026, however there is some still potentially available in 2026-2028 FID projects. Additionally, spot cargos will likely be available from these projects while in operation in the late 2020s. A global LNG supplier may offer a contract for a number of cargos annually that are supplied from one of the North American West Coast projects or other sources in the Pacific, provided both the vessel and LNG specifications are appropriate for Alaska. Those spot cargos will most likely be priced using JKM indexation. Once this project reaches a stage where an FID commitment is imminent, it would be appropriate to seek a multi-year contract for FOB or DES LNG supply from several of the developing projects and worldwide LNG suppliers, using a structured expression of interest and bidding process.

139. However, even at this early stage, and given the bespoke characteristics of the Alaska regulatory and market environment, we advise conducting an informal outreach to suppliers as early as Phase II of this project, even as non-LNG import options are still under consideration. Confidential discussions with willing suppliers would provide valuable information on the need for this project to procure its own vessels or shipping arrangements, exact LNG chemical composition available from each suppliers, potential indexation and price structures available, and flexibility of seasonal and annual contract volumes. This information would greatly inform technical and commercial planning of the project.

5.4 Statistical Risk Analysis of Recommended Options

5.4.1 Risk Factors of Different Recommended Options

140. The market price risk volatility addressed above is only a part of the potential cost and schedule risk that needs to be evaluated and mitigated for the selected option. For options with large capital investments, additional risk will lie in the ultimate cost of the infrastructure and the date commercial operations can be achieved. The current level of certainty in the cost estimates of the options does not lend itself to a productive risk analysis due to the immaturity of the project scope and estimates; however, in the next phase with fewer options under consideration, it is highly recommended.

5.4.2 Future Risk Analysis Recommendation

141. A Monte Carlo simulation is a common technique used to assess the impact of uncertainty on the economic output such as the NPV of cash flows or the levelized cost of supply. The simulation involves selecting key inputs which typically include capital costs, operating costs, and LNG prices and assigning a probabilistic distribution to those inputs using computer software such as

@Risk[94] or Crystal Ball[95]. These inputs are then used in a cash flow model that combines these inputs by sampling the input distributions to calculate a median economic output and a confidence range indicating the likelihood that the economic parameter would be lower or higher than a certain value. For example, a Monte Carlo could quantify a mean cost of alternative gas supply of $15/mmbtu with a 95% chance that the ultimate cost of supply will not exceed $20/mmbtu and a 5% chance that the ultimate cost of supply will be less than $12/mmbtu.

[94] Palisade, *@Risk Probabilistic Risk Analysis in Excel*, https://www.palisade.com/risk/?gclid=Cj0KCQjwxYOiBhC9ARIsANiEIfbbQoh42P7VupRbwECl9ONAdSoR5is5PmHL08PQFvztrsfDdzod7fAaAuKVEALw_wcB.

[95] Oracle, *Crystal Ball*, https://www.oracle.com/applications/crystalball/.

6 RECOMMENDATIONS AND NEXT STEPS

6.1 Recommended Actions to Confirm Feasibility of Top Scoring Options

142. BRG recommend the following scope of work as part of Phase II, estimated to take 4-6 months:

a. Utilities individually continue to work with Cook Inlet producers and the State to promote and secure additional contracted supply and promote alternative development.

b. The utilities' Working Group should pursue several top-scoring options in order to further define scope, schedule and commercial viability, specifically, 1) Modification of existing Kenai LNG facility (via commercial discussions with owner); 2) Scope definition and planning for FSRU option; 3) Greenfield Port and Regas site selection and feasibility assessment for LNG imports if retrofit options become unavailable; 4) Market survey to further define availability and cost of LNG; and 5) Optimization and feasibility assessment of the In-State Pipeline option with AGDC and State of Alaska in areas of permitting critical path and financing structure.

c. Complete permitting due diligence of all top-scoring options and identify key bottlenecks and showstoppers.

d. For all top-scoring options, develop draft venture model, project finance structure and plan of engagement with capital markets.

e. Refine cost of supply estimates for the top-scoring options, including Greenfield Port and Regas, if existing infrastructure in Nikiski becomes non-feasible or excessively risky.

f. Select one permanent solution or multiple short-term and long-term options to pursue by the end of 2023.

6.2 Project Management Next Steps

143. The following are recommended next steps in Phase II in order to prepare to commence preliminary engineering on a major project, if executed by the Working Group or an affiliated joint venture:

a. Assess Working Group's project delivery capabilities and provide recommendations.

b. Confirm current operating environment, and available resources, processes and enabling technologies.

c. Measure the as-is maturity level of key capability areas required to deliver a large complex project.

d. Define an ideal to-be maturity level based on the complexity of the selected option.

e. Perform a gap analysis and develop recommendations for improvement.

f. Develop an implementation roadmap.

g. Conduct an alternates analysis.

h. Provide a recommendation for contract/procurement strategy.

i. Assist the Working Group in establishing a project management office.