STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	John M. Espindola, Chairman Steve DeVries Mark Johnston Robert M. Pickett John C. Springsteen
In the Matter of the Petition Filed by ENSTAR NATURAL GAS COMPANY, LLC for Advanced Determination of Decisional Prudence for Natural Gas Storage Project	Docket No. U-26-____

PETITION OF ENSTAR NATURAL GAS COMPANY, LLC FOR ADVANCE DETERMINATION OF DECISIONAL PRUDENCE AND REQUEST FOR EXPEDITED CONSIDERATION

With this Petition, ENSTAR Natural Gas Company, LLC ("ENSTAR" or "Company")[1] respectfully requests that the Regulatory Commission of Alaska ("Commission") find that ENSTAR's decision to develop and operate a natural gas storage facility and associated facilities in the City of Kenai ("Project") is prudent, in the public interest, and consistent with the Company's duties under AS 42.05, the Alaska Public Utilities Regulatory Act. An advance determination of prudence in this proceeding will help ensure that ENSTAR can undertake this critical Project to continue meeting the gas supply needs of thousands of residents and businesses in Southcentral Alaska.

[1] ENSTAR is a Commission-regulated public utility providing natural gas service. All correspondence to ENSTAR relating to this docket may be directed to undersigned counsel. ENSTAR is a limited liability company organized under Delaware law and its address is 5151 Fairbanks Street, Anchorage, Alaska 99503.

As discussed below, ENSTAR respectfully requests that the Commission consider this Petition on an expedited basis. In particular, the Company requests that the Commission issue a final order granting the relief requested herein within 45 days of this filing. Granting this Petition on an expedited basis will help ensure that ENSTAR can continue to fulfill its duty to provide reliable, safe natural gas service to the Company's Gas Sales Service customers ("Customers").

INTRODUCTION

1. ENSTAR is a regulated public utility that delivers and sells natural gas to over half the population of Alaska.[2] The Company currently serves approximately 156,000 separate meters in the Southcentral region of the state, from the City of Houston to the Homer Spit at the southern tip of the Kenai Peninsula.[3] An overwhelming majority of those meters—more than 142,000—are associated with residential homes of Alaskan families and individuals.[4] The rest of them provide service to large and small businesses, critical facilities, and other utility companies throughout ENSTAR's service territory.[5] Under Alaska law and the terms and conditions of its tariff, the Company has the obligation to furnish and maintain "adequate, efficient and safe service and facilities," and this service "shall be reasonably continuous and without unreasonable interruption or delay."[6]

[2] Affidavit of Inna B. Johansen ("Johansen Aff.") ¶ 6.

[3] *Id.*

[4] *Id.*

[5] *Id.*

[6] *Id.* ¶ 7 (quoting Alaska Statute 42.05.291(a)).

2. The Project proposed in this proceeding represents a significant step in ENSTAR's long history of delivering safe, reliable service to the thousands of Alaska homes and businesses throughout its service territory. As Company representative John D. Sims explains in his supporting affidavit, ENSTAR proposes to acquire a depleted natural gas reservoir and associated facilities in the City of Kenai from AIX Energy, LLC ("AIX").[7] The depleted reservoir site includes four existing wells along with other facilities, and the Company will install the major equipment upgrades necessary to ensure that the facility can reliably store, inject, and withdraw natural gas in accordance with federal and state engineering and design standards.[8]

3. To demonstrate the prudence of this Project and its importance for helping ensure that ENSTAR meets the gas supply needs of its Customers, this Petition includes affidavits and supporting materials from the following Company representatives:

- ***John D. Sims***, President, ENSTAR, Alaska Pipeline Company, LLC, and Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"). Mr. Sims provides a general overview of ENSTAR's filing and a high-level explanation of why the Project is needed. In addition, he provides a high-level description of the Project itself, including a description of the positive impacts the Project will have on the local economy and in Southcentral Alaska overall. He also explains why an advance determination of prudence is necessary for ENSTAR to undertake the Project, discusses the support the Project has received from various stakeholders, and supports the Company's request for an expedited decision on this filing.

- ***Inna B. Johansen***, Vice President of Regulatory and Gas Supply, ENSTAR and CINGSA. Ms. Johansen discusses ENSTAR's obligation to provide safe and reliable service to its Customers and how the Company meets its gas supply needs today. She also describes Customers' natural gas demand, ENSTAR's current gas supply resources, and its assessments of options

[7] Affidavit of John D. Sims ("Sims Aff.") ¶ 7.

[8] *Id.*

supporting the decision to develop the Project. Finally, Ms. Johansen discusses cost recovery associated with the Project and ENSTAR's plans for reporting on the status of the Project's development to the Commission.

- ***Matthew S. Federle***, Director of Gas Plant Storage, ENSTAR. Mr. Federle discusses the planning, design, and engineering for the proposed Project. He also describes ENSTAR's cost estimates, management, and development schedule for the Project.

In addition to these and other supporting materials, ENSTAR's filing also includes a report from Arctic Slope Regional Corporation Consulting & Environmental Services, LLC ("ACES"), which the Company commissioned to identify and evaluate potential natural gas reservoirs in the Cook Inlet Basin that might be available for gas storage.[9] As explained below and in the affidavits of Messrs. Federle and Sims, the ACES report confirms that the Upper Tyonek Pool in the Kenai Loop Field—the site of this Project—is the only viable option for development of a natural gas storage facility for ENSTAR.[10] A copy of the ACES report is attached to Mr. Federle's affidavit as Exhibit MSF-4.

4. Based on the information included in this filing, ENSTAR respectfully requests that the Commission issue an order with the following findings:

(a) ENSTAR's Petition and supporting materials demonstrate that the proposed Project will benefit the public by ensuring that ENSTAR can continue meeting its Customers' gas supply needs into the future, especially considering the well-documented gas supply challenges confronting Southcentral Alaska; and

(b) ENSTAR's Petition and supporting materials demonstrate that the Company's proposal to develop and operate the Project is reasonable and prudent, in the public interest, and consistent with the Company's obligations under the Alaska Public Utilities Regulatory Act.

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[9] Sims Aff. ¶ 25; Affidavit of Matthew S. Federle ("Federle Aff.") ¶ 21.

[10] Sims Aff. ¶ 25; Federle Aff. ¶ 22.

DISCUSSION

5. As this filing demonstrates, the proposed Project is reasonable, prudent, and in the public interest. Granting ENSTAR's request for an advance determination of prudence and request for expedited consideration will help ensure that this critical Project moves forward on the necessary timeline for the benefit of Customers.

I. The Proposed Project

6. The Project proposed in this Petition represents a significant step in ENSTAR's long history of delivering safe, reliable service to the thousands of Alaska homes and businesses throughout its service territory. ENSTAR will acquire a depleted natural gas reservoir and associated facilities.[11] Located in the Kenai Peninsula Borough in the City of Kenai, the depleted reservoir site includes four existing wells, a dehydration unit, a compressor, and a six-inch pipeline connecting the Project to the existing natural gas transmission system, along with other minor operational facilities.[12] Three of the wells will be repurposed to provide injections and withdrawals and one will be repurposed as a disposal well.[13] The Company will install the major equipment upgrades necessary to ensure that the facility can reliably store, inject, and withdraw natural gas in accordance with federal and state engineering and design standards.[14]

[11] Sims Aff. ¶ 7.

[12] *Id.*

[13] Federle Aff. ¶ 8.

[14] Sims Aff. ¶ 7; Federle Aff. ¶¶ 10-18.

7. ENSTAR representative Mr. Federle, who is responsible for managing the operations of the CINGSA storage facility, describes the various components of the Project in detail in his supporting affidavit.[15] As he explains, ENSTAR will convert the nearly depleted Upper Tyonek Pool of the Kenai Loop Unit into an underground gas storage reservoir.[16] Initially, the reservoir will have a total storage volume of roughly 25 billion cubic feet ("Bcf"), including 17 Bcf of "working gas" (gas that is actually available for withdrawal and delivery to Customers) and 8 Bcf of "base gas" (gas that is necessary to maintain adequate pressure in the reservoir).[17] The withdrawal pressure will come from the three existing wells that penetrate the reservoir, which ENSTAR will upgrade to meet applicable design and safety standards for natural gas storage.[18] Injection rates at the facility will be significantly higher as a result of compression that ENSTAR plans to install.[19] The Company will convert the fourth existing well into a disposal well for the disposal of drilling fluids, produced waters, and other waste byproducts associated with natural gas storage operations.[20] As compared to the alternative approach of shipping disposal waste offsite, ENSTAR expects that operating the onsite disposal well will produce significant cost savings each year.[21]

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[15] *See generally* Federle Aff. ¶¶ 6-20.

[16] *Id.* ¶ 6.

[17] *Id.* ¶ 6.

[18] *Id.* ¶ 8.

[19] *Id.*

[20] *See id.* ¶ 8, 12-13.

[21] *Id.* ¶ 14.

8. Having previously developed the CINGSA storage facility in 2011 and the CINGSA expansion in 2024, ENSTAR has significant experience constructing and operating natural gas storage assets. The Project will utilize similar design criteria as the CINGSA facility, which will have multiple benefits, including safer and more reliable operations by employees familiar with the equipment, and efficiencies that will reduce operating costs.[22] Additionally, the same ENSTAR team that manages CINGSA's storage assets will also be responsible for operating the proposed Project.[23] These employees will utilize the same standard operating procedures, policies, and best practices that ENSTAR has developed and relied upon to deliver safe and reliable storage service at the CINGSA facility since inception.[24]

9. As Mr. Sims explains in his affidavit, in the latter part of 2024, ENSTAR was approached with an opportunity to acquire existing infrastructure for gas storage.[25] The Company then conducted an analysis of potential natural gas reservoirs in the Cook Inlet Basin.[26] The Company commissioned ACES to identify potential reservoirs that might be available for natural gas storage.[27] Of the existing 48 defined gas pools in the Cook Inlet Basin, the ACES analysis identified fourteen potential candidates.[28] Ultimately, for a variety of reasons, ACES concluded that the Upper Tyonek Pool in the Kenai Loop

[22] *Id.* ¶ 19.

[23] *Id.* ¶ 20.

[24] *Id.*

[25] Sims Aff. ¶ 22.

[26] *Id.* ¶¶ 24-25; Federle Aff. ¶¶ 21-22.

[27] Sims Aff. ¶ 25; Federle Aff. ¶ 21.

[28] Federle Aff. ¶¶ 21-22.

Field—the site of this Project—is the only viable option for a new natural gas storage facility for ENSTAR.[29]

II. ENSTAR's Need for Additional Natural Gas Storage

10. The Project is a necessary response to the significant and well-documented challenges that ENSTAR and other utilities currently face in procuring natural gas supply in Cook Inlet.[30] In 2022, Hilcorp Alaska, LLC ("Hilcorp") informed ENSTAR and other Alaska utility companies that Hilcorp would not be extending their existing contracts.[31] Hilcorp is the largest natural gas producer in Alaska, and ENSTAR's contract with Hilcorp currently provides approximately 85% of the natural gas volumes ENSTAR's Customers require each year, and a majority of the deliverability.[32] With the contract set to expire on March 31, 2033, the Company must find alternative arrangements to replace this vitally important source of natural gas supply.[33] As the Commission knows, the Company has been actively exploring its options for several years.[34]

11. The proposed Project will address two critical needs for ENSTAR. First, the new storage facility will help ensure that ENSTAR has adequate gas supply to meet its Customers' needs into the future.[35] With additional storage capacity, the Company will be

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[29] Sims Aff. ¶ 25; Federle Aff. ¶ 22.

[30] Sims Aff. ¶ 8.

[31] *Id.*

[32] *Id.*

[33] *Id.*

[34] *See, e.g.*, U-22-090, *ENSTAR Natural Gas Company, LLC's Petition for Approval to Create a Deferred Regulatory Asset for Costs Associated with Studying and Securing Long-Term Gas Supplies for the Alaska Railbelt*, dated Nov. 10, 20222, at 2-4.

[35] Sims Aff. ¶ 9.

able to purchase gas supply as it becomes available and then store those volumes for future customer use.[36] Given the gas supply challenges in Cook Inlet, having the ability to procure gas produced at any time—rather than scrambling to procure it "just in time"—will help ensure reliable, uninterrupted service to Customers.[37] In fact, a natural gas producer in the region has informed the Company that it is willing to increase production, but only if adequate storage is available in the market.[38] Second, the Project will ensure that ENSTAR has adequate deliverability and injectability to store and remove the gas and deliver it to Customers through the Company's distribution system when needed.[39] "Deliverability" refers to the rate at which gas flows through the pipeline system, while "injectability" refers to the rate at which gas can be injected into the facility for storage, and both are essential to providing safe and reliable gas service.[40] In short, this Project will resolve two critical needs: it will ensure that ENSTAR has adequate gas supply, and it will ensure that the Company can actually deliver that supply to Customers, particularly during periods of peak demand.[41]

12. The changing gas supply environment in Southcentral Alaska has led to a simple reality: ENSTAR must have additional storage to meet its Customers' needs. As Ms. Johansen indicates in her affidavit, going forward, the Company will have only three

[36] *Id.*

[37] *Id.*

[38] *Id.* ¶ 10; Johansen Aff. at 52.

[39] Sims Aff. ¶ 9.

[40] *Id.*

[41] *Id.*

possible sources of gas supply: (1) gas produced from the Cook Inlet; (2) deliveries of liquefied natural gas ("LNG"); and (3) gas from a new North Slope pipeline that will potentially be constructed as part of the Alaska LNG Project.[42] The extent to which ENSTAR will rely on each of these resources will depend on numerous factors, but in all three situations, one fact remains constant: ENSTAR will need additional storage to accommodate gas supply. None of these three options will be possible without additional storage capacity.

III. Project Identification, Evaluation, and Selection

13. As Ms. Johansen explains, based on the Company's projected Customer demand and evolving arrangements for acquiring natural gas supply, the Company performed a comprehensive assessment of its natural gas storage requirements going forward.[43] Based on the results of this analysis, ENSTAR determined that it will need to develop up to 15 Bcf of storage capacity as early as 2027, and will need to increase the capacity to 24 Bcf to manage LNG supply.[44] In addition to new storage capacity, the Company also will additional injection and withdrawal capacity for deliveries to accommodate various gas supply sources.[45] While recognizing that gas supply options may change over time, in its storage requirements analysis, ENSTAR assumed varying gas supply arrangements over the following timeline: (1) the Company would obtain deliveries

[42] *See* Johansen Aff. at 35.

[43] *See generally id.* ¶¶ 19-65.

[44] *Id.* ¶ 65.

[45] *Id.*

of Cook Inlet gas from 2025 through early 2033 ("Cook Inlet Deliveries"); (2) the Company would transition fully to LNG imports from 2033 to 2038 ("LNG Deliveries"); and (3) the Company would obtain deliveries from a potential North Slope pipeline from 2039 to 2045 ("NS Pipeline Deliveries").[46] Ms. Johansen describes the Company's analysis of its projected gas supply and storage needs in more detail in her affidavit.

14. ENSTAR follows a deliberate, structured process to evaluate and identify the best possible natural gas storage solution to meet its Customers' needs at reasonable cost.[47] The Company applied seven general criteria to evaluate potential storage options, including: whether the project meets ENSTAR's storage requirements, including both capacity and deliverability; schedule risk; storage cost; scalability (to accommodate possible growth in ENSTAR's capacity and deliverability requirements); operational flexibility; potential for stranded costs; and project complexity and ease of integrating a storage project into various potential gas supply scenarios.[48]

15. To identify the best possible solution to its future storage needs, ENSTAR evaluated various storage options that the Company could efficiently integrate into its gas supply portfolio. ENSTAR considered three alternatives: (1) storage service from Hilcorp Alaska Gas Storage, LLC ("Hilcorp Storage"); (2) additional expansion of the CINGSA storage facility; and (3) development of a new storage facility.[49] The Company evaluated

[46] *Id.* ¶ 35.

[47] *Id.* ¶ 67.

[48] *Id.* at Table 6.

[49] *Id.* ¶ 69.

each option based on a variety of criteria, including but not limited to commercial availability, deliverability, injection and withdrawal flexibility, cost transparency, and long-term reliability.[50] As a result of its analysis, ENSTAR determined that developing the proposed Project is the best and most prudent option to pursue.

16. For a variety of reasons, the first option that ENSTAR considered—acquiring storage capacity from Hilcorp Storage—simply is not feasible. As recent developments confirm, Hilcorp Storage simply does not have adequate capacity to meet the Company's needs.[51] On January 5, 2026, Hilcorp Storage filed a tariff advice letter requesting Commission approval of a firm storage service ("FSS") agreement with its first customer, its affiliate Hilcorp Cook Inlet, LLC ("Hilcorp Cook Inlet").[52] According to the letter, Hilcorp Cook Inlet will acquire 27 Bcf of the 38 Bcf total amount of capacity available from Hilcorp Storage.[53] The letter also states that Hilcorp Storage has been working to execute FSS agreements with two additional customers, Chugach Electric Association, Inc. ("Chugach") and Matanuska Electric Association, Inc. ("MEA"), and that it will submit those agreements to the Commission upon execution.[54] In fact, on January 8, 2026, Chugach announced that it has executed an FSS agreement with Hilcorp Storage under which Chugach will receive up to 5 Bcf of storage capacity (in escalating amounts)

[50] *Id.* ¶ 68.

[51] *Id.* ¶ 75.

[52] Hilcorp Alaska Gas Storage, LLC, Tariff Letter No. 1-787, filed Jan. 5, 2026, at 1 ("Tariff Letter No. 1-787).

[53] *Id.* at Attachment A, at 7; Johansen Aff. ¶ 72-73.

[54] Tariff Letter No. 1-787 at 1.

through 2030.[55] In light of these developments, the vast majority of the Hilcorp Storage capacity is already subscribed, and the remaining capacity is not even close to enough to meet ENSTAR's needs.[56] Moreover, even if Hilcorp Storage had adequate capacity available, utilizing the capacity may be operationally challenging for ENSTAR due to provisions in Hilcorp Storage's tariff.[57]

17. Likewise, the second option ENSTAR considered—adding storage capacity at the CINGSA facility—also is not feasible. As initially constructed, the CINGSA facility had a storage capacity of 11 Bcf, an injection capacity of 150 MMcfd, and a withdrawal capacity of 150 MMcfd.[58] The CINGSA expansion in 2024 added 2 Bcf of storage, 75 MMcfd of injection, and 65 MMcfd of withdrawal, but ENSTAR has already contracted for all of that capacity.[59] But, no further expansion of the CINGSA facility is possible.[60] Moreover, the daily and seasonal usage of CINGSA's services demonstrates that ENSTAR is optimizing its storage service in CINGSA and does not have excess capacity to meet ENSTAR's needs.[61]

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[55] Chugach Electric Association, *Chugach Electric secures new gas storage contract with Hilcorp Alaska Gas Storage* (Jan. 8, 2026), https://www.chugachelectric.com/your-cooperative/news-community/news-releases/2026/1/8/chugach-electric-secures-new-gas-storage-contract-with-hilcorp-alaska-gas-storage; Johansen Aff. ¶ 73.

[56] Johansen Aff. ¶ 74-75.

[57] *Id.* ¶ 75.

[58] *Id.* ¶ 76.

[59] *Id.*

[60] *Id.*

[61] *Id.* ¶ 50.

18. As mentioned above, to validate the site for the proposed Project, ENSTAR retained ACES to evaluate natural gas pools in Cook Inlet that might potentially be available for a natural gas storage facility. ACES updated a previous analysis that ENSTAR commissioned in 2009, which identified 48 defined gas pools in the upper Cook Inlet Basin and concluded that eleven were prospective candidates worthy of additional review.[62] In addition to the eleven prospects identified in the initial study in 2009, the ACES updated analysis identified three additional prospects.[63] The analysis revealed that 13 of the 14 prospective candidates simply are not available for development—one is now the CINGSA storage facility, and the other twelve are owned by Hilcorp (or Hilcorp affiliates) and are within fields under active development.[64] But ACES confirmed that the fourteenth pool—the Kenai Loop Upper Tyonek Gas Pool, which was not discovered until 2011, after the initial 2009 analysis—is commercially available for acquisition, and based on ENSTAR's assessment, satisfies all of the Company's criteria for a new natural gas storage facility and is the ideal candidate for this Project.[65]

19. In short, through the process described above, the Company concluded that the proposed Project is not only required for the Company to provide natural gas service in Alaska, but also represents the best available option for ensuring that the Company can continue to meet its obligations as an Alaska public utility.

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[62] Federle Aff. ¶ 21.

[63] *Id.* ¶ 22.

[64] *Id.*

[65] Sims Aff. ¶ 25; Federle Aff. 22.

IV. Project Benefits

20. As Mr. Sims and Ms. Johansen explain in their affidavits, the Project will provide significant benefits to ENSTAR's Customers throughout Alaska. First and foremost, developing additional gas storage capacity will help ensure that the Company continues meeting its public obligation to deliver safe and reliable natural gas service—a priority that has become especially important considering the gas supply challenges in Cook Inlet. Under all three of the supply scenarios the Company analyzed—Cook Inlet Deliveries, LNG Deliveries, and NS Pipeline Deliveries—the Project will play a critical role in ensuring deliverability of seasonal gas supplies.[66] Second, with new storage capacity, ENSTAR will be able to store substantial amounts of gas during Cook Inlet Deliveries and LNG Deliveries, thereby ensuring the Company has adequate gas supply on hand to meet Customers' future needs.[67] Third, when LNG Deliveries occur, the Company will be able to inject large volumes of gas in a short period of time, and then withdraw large amounts of gas as needed to meet peak winter demand and replace the declining gas production in Cook Inlet.[68] In fact, without additional storage, injection, and withdrawal capacity, LNG Deliveries will not be possible for ENSTAR.[69]

21. Moreover, in the first several years of the Project's operation, having additional storage capacity will give ENSTAR greater flexibility in procuring gas supply

[66] Johansen Aff. ¶ 79.

[67] *Id.*

[68] *Id.*

[69] *Id.* ¶ 56; Sims Aff. ¶ 9.

from Cook Inlet.[70] With this new storage facility, ENSTAR will be able to procure gas supply as it becomes available and store it for future use—a strategy that will be especially important as local supply becomes even more constrained.[71] ENSTAR will also achieve significant efficiencies in how it operates the facility.[72] Specifically, during times of high demand, ENSTAR will be able to replenish its storage inventory balance in the CINGSA facility quickly and thereby maintain high deliverability rates throughout the heating season.[73] Other operational benefits of this Project include: (1) assistance with seasonal load balancing; (2) peak-shaving capability during short-term spikes in demand; (3) ability to assist with reliability and contingency planning in case of disruptions and other events; and (4) operational flexibility.[74]

22. The Project also will have substantial economic benefits for Alaska.[75] ENSTAR prioritizes the hiring of Alaska employees and vendors, and the Company expects to complete much of the work required for this Project utilizing local businesses and contractors.[76] As a comparison, when CINGSA undertook its expansion project in 2024, it hired more than 100 different Alaska companies to complete the project, and these firms relied on Alaska employees to perform more than 126,000 hours of labor.[77]

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[70] Johansen Aff. ¶ 79.

[71] *Id.*

[72] *Id.* ¶¶ 77, 79.

[73] *Id.* ¶ 79.

[74] *Id.* ¶ 81.

[75] Sims Aff. ¶ 30.

[76] *Id.*

[77] *Id.*

ENSTAR expects the numbers for this Project to be similar, and estimates that the Project will infuse $50 million into the local economy.[78]

V. Cost Recovery

23. ENSTAR currently estimates that the proposed Project will cost approximately $240 million to develop. As Mr. Sims explains, beginning in 2027, the Project will increase Customer bills by less than $1 per Mcf, or approximately $10 to $12 per month, for an average residential Customer.[79] In this Petition, ENSTAR requests only that the Commission grant an advance determination that the Project is prudent. If the Commission grants the relief requested in this Petition, the Company will seek to recover the costs associated with the Project through a future rate filing consistent with the Commission's procedures, orders, and applicable law.

24. Assuming the Commission grants an advance determination of prudence on the timeline requested in this Petition, the Company anticipates that advanced development of the Project will begin within months, with a projected in-service date near the end of 2026.

VI. ENSTAR's Need for an Advance Determination of Prudence

25. As this filing demonstrates, an advance determination of prudence is necessary to ensure that ENSTAR can complete the proposed Project and continue meeting

[78] *Id.*

[79] *Id.* ¶ 29.

its obligation to deliver safe and reliable natural gas service to Customers. Mr. Sims discusses the need for the advance prudence determination in more detail in his affidavit.[80]

26. The Commission has previously described the standard under which it will review a utility's request for an advance determination of prudence. When CINGSA requested an advance prudence determination of a proposed project in 2018, the Commission described its standard of review as follows:

> We find that under any prudency standard, the reviewed capital investment decision must first be found to be justified by the utility's service obligations. Specifically, the investment (whether reviewed before or after completion) must be required for the utility to provide the services authorized by its certificate of public convenience and necessity (certificate) and provide them in a manner that complies with the statutory requirements of AS 42.05.291. Under these provisions each utility must furnish and maintain "adequate, efficient, and safe service and facilities" and the utility's provided service "shall be reasonably continuous and without unreasonable interruption or delay."
>
> Once this necessary relationship has been established, inquiry turns to whether the chosen investment represents a "prudent" way of providing those required services. In the case of a post-construction prudency determination, we (like other regulators) have concluded that protecting the utility's actual expenditure of its funds in order to provide required services justifies the imposition of procedural limitations on challenges to decisional prudency. Initially, protection is extended through a presumption of prudency. Absent a challenger's presentation of sufficient evidence of "imprudence," the utility is not required to establish the prudency of its decisions. Thereafter, the utility is advantaged by our use of a lesser standard of prudency met by proving its decision was "a reasonable one." The utility is not required to prove its full consideration of all options

[80] *See id.* ¶¶ 32-35.

> before ultimately choosing a "good" option, one of the "better" options, or even the "best" option.
>
> Because there is not an actual utility expenditure to protect in the case of a pre-construction determination, we agree with the AG and the other parties that CINGSA does not enjoy a presumption of prudency in this instance. Therefore, we conclude that in order to prevail, CINGSA must produce a preponderance of evidence on both requirements described above. Initially, we must find that CINGSA has produced a preponderance of evidence establishing that its Project is prudent because it is "necessary" in order to provide an authorized service (in this case daily withdrawal service) that is "adequate" in amount and made available in a manner that is "reasonably continuous and without unreasonable interruption." If we find that CINGSA has carried its burden in this regard, then we must proceed to determine whether the Project is a "prudent" option for obtaining that result, using a yet to be articulated standard that either mirrors the "reasonable decision" one adopted in previous post-construction determinations or is a more stringent standard for specific application to pre-construction determinations such as "best decision" among feasible options.[81]

ENSTAR's filing in this proceeding satisfies the Commission's standard. First, as Mr. Sims explains, the Project "is required for the utility to provide the services authorized by its certificate of public convenience and necessity . . . and provide them in a manner that complies with the statutory requirements of AS 42.05.291."[82] Second, the Company's filing also demonstrates that the proposed Project is prudent, and that it represents the best option for ensuring that the Company can continue to meet its obligations as an Alaska public utility.

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[81] Order U-18-024(17), *Order Denying Petition, in Part, and Closing Docket*, dated February 28, 2019, at 15-17.

[82] Sims Aff. ¶ 42.

27. For various reasons, an advance determination of prudence is necessary to ensure that ENSTAR can complete this critical Project in a timely manner. First, given the magnitude of this investment, ENSTAR will not be able to access the necessary financing unless it receives confirmation that the Commission agrees the Project is prudent. Second, an advance determination of prudence will likely be a condition precedent to closing any potential transaction with AIX. As a result, if ENSTAR does not obtain a prudence determination in this proceeding, it will be unable to close on the acquisition and the Project will not go forward. Given the importance of this issue, the Company believes the Commission should play a role in evaluating and selecting the storage projects that will help meet the natural gas needs of Alaska homes and businesses for decades to come.

VII. Request for Expedited Consideration

28. ENSTAR respectfully requests that the Commission consider this Petition on an expedited basis. ENSTAR could potentially need storage as early as the fourth quarter of 2026, which is less than one year away.[83] A natural gas production company in Alaska—BlueCrest Alaska Operating, Inc. ("BlueCrest")—has already committed to supplying ENSTAR with gas by the fourth quarter of 2026, but only if the Company has the ability to store those volumes (or use them immediately).[84] Otherwise, if ENSTAR does not have the necessary storage capacity, BlueCrest could lose its financing and could need to search for new sources of capital, all of which could cause further delay in the

[83] *Id.* ¶ 10; Johansen Aff. ¶ 52.

[84] *Id.*

production of gas.[85] Additionally, the Company also will need new storage in 2027 so that it can receive new gas supplies from Furie Operating Alaska, Inc.[86] Further, after ENSTAR executes its contract to acquire the depleted gas reservoir and associated facilities, the Company will need time to execute additional commercial agreements, including natural gas storage leases, a rig procurement agreement, surface leases, and arrangements for the procurement of long-lead items and materials.[87] For example, based on vendor input, ENSTAR will need six months to procure the pipe necessary to bring the Project in-service.[88] That means that if the Commission were to grant ENSTAR's request for an advance prudence determination by March 1, 2026, the Company will be able to receive the pipe by August, which will help ensure that the Project goes into service by the fourth quarter.[89] As another example, and also based on communications with vendors, ENSTAR will need approximately nine to ten months to procure the compressor and compressor skid necessary to make the Project fully functional.[90] Finally, obtaining an advance prudence determination on an expedited basis will facilitate ENSTAR's process of obtaining the additional approvals and leases from other Alaska agencies and entities, including the Alaska Oil and Gas Conservation Commission, the Department of Natural Resources, the Alaska Mental Health Trust, and Cook Inlet Regional Incorporated.[91]

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[85] Johansen Aff. ¶ 52.

[86] *Id.* ¶ 53.

[87] Sims Aff. ¶ 10.

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] *Id.*; Federle Aff. ¶ 25 (listing additional approvals).

29. Given all these factors, expedited consideration of this Petition is wholly appropriate, because it will help ensure that the Project moves forward on the necessary timeline. As stated above, the Company respectfully requests that the Commission issue an order granting the relief requested herein within 45 days of this filing. In Order U-18-024(1), the Commission found that the 180-day timeframe set forth under AS 42.05.175(i) applied to a petition for an advance determination of prudence.[92] To the extent that a motion for expedited consideration is necessary, and to the extent that the 180-day timeframe set forth under AS 42.05.175(i) or any other statutory or regulatory timeframe applies to this Petition, ENSTAR is filing a motion for expedited consideration concurrently with this Petition.

VIII. Conclusion and Request for Relief

30. As the Commission knows, the natural gas supply challenges that ENSTAR and other utilities in Southcentral Alaska currently face are significant, and the need to resolve them is urgent. As this filing demonstrates, the proposed Project is a necessary and prudent step to helping ENSTAR overcome these challenges. By granting an advance determination of prudence in this proceeding, the Commission will help ensure that ENSTAR can continue to fulfill its obligation to provide safe, reliable service to the thousands of homes and business throughout its service territory. Accordingly, ENSTAR

[92] Order U-18-024(1), *Order Designating Parties, Inviting Participation by the Attorney General and Intervention, Scheduling Prehearing Conference, Extending the Time to Rule on Petition for Confidential Treatment, Addressing Timeline for Decision, Designating Commission Panel, and Appointing Administrative Law Judge*, dated May 11, 2018, at 3.

respectfully requests that the Commission review this Petition and issue an order with the following findings:

(a) ENSTAR's Petition and supporting materials demonstrate that the proposed Project will benefit the public by ensuring that ENSTAR can continue meeting its Customers' gas supply needs into the future, especially considering the well-documented gas supply challenges confronting Southcentral Alaska; and

(b) ENSTAR's Petition and supporting materials demonstrate that the Company's proposal to develop and operate the Project is reasonable and prudent, in the public interest, and consistent with the Company's obligations under the Alaska Public Utilities Regulatory Act.

ENSTAR requests that the Commission issue its order granting the Company's request for relief within 45 days of this filing to ensure that the Company can move forward with this critical Project on the necessary timeline.

Dated this 12th day of January, 2026, at Anchorage, Alaska.

By: _____

Myles F. Reynolds
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James G. Ritter
Virginia State Bar No. 82572
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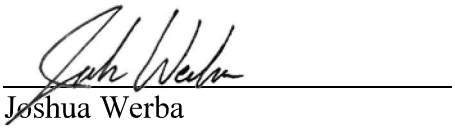
ATTORNEYS FOR ENSTAR NATURAL GAS COMPANY, LLC

CERTIFICATE OF SERVICE

I hereby certify that on January 12, 2026, a true and correct copy of the foregoing document was served by electronic mail on the following:

Jeffrey J. Waller
Office of the Attorney General
1031 W. 4th Avenue, Suite 200
Anchorage, Alaska 99501
jeff.waller@alaska.gov



Joshua Werba
Regulatory Financial Analyst

VERIFICATION

I, John D. Sims, say on oath or affirm that I have read the foregoing document and believe all statements made in the document are true.

John D. Sims

SUBSCRIBED AND SWORN TO OR AFFIRMED before me at Anchorage, Alaska, this 12th day of January, 2026, to which witness my hand and seal.

Notary Public, State of Alaska
My commission expires: November 1, 2029

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	John M. Espindola, Chairman Steve DeVries Mark Johnston Robert M. Pickett John C. Springsteen
In the Matter of the Petition Filed by ENSTAR NATURAL GAS COMPANY, LLC for Advanced Determination of Decisional Prudence for Natural Gas Storage Project	Docket No. U-26-____

ENSTAR NATURAL GAS COMPANY, LLC'S MOTION FOR EXPEDITED CONSIDERATION OF PETITION FOR ADVANCED DETERMINATION OF DECISIONAL PRUDENCE FOR NATURAL GAS STORAGE PROJECT

Pursuant to 3 AAC 48.091(g), ENSTAR Natural Gas Company, LLC ("ENSTAR" or "Company") moves for expedited consideration of its primary Petition for Advanced Determination of Decisional Prudence for Natural Gas Storage Project ("Petition"). ENSTAR moves for expedited consideration to the extent that a motion is necessary and to the extent that the deadline set forth in AS 42.05.175(i) is applicable.

ENSTAR submits its primary Petition to request an advance determination of prudence for a proposed natural gas storage project ("Project"). The Project represents a significant step in ENSTAR's long history of delivering safe, reliable service to the thousands of Alaska homes and businesses throughout its service territory.[1] ENSTAR proposes to acquire a depleted natural

[1] Affidavit of John D. Sims ¶ 3.

gas reservoir and associated facilities in the City of Kenai.[2] The depleted reservoir site includes four existing wells along with other facilities, and the Company will install the major equipment upgrades necessary to ensure that the facility can reliably store, inject, and withdraw natural gas in accordance with federal and state engineering and design standards.[3]

The Project is a necessary response to the significant and well-documented challenges that ENSTAR and other utilities currently face in procuring natural gas supply in Cook Inlet.[4] In 2022, Hilcorp Alaska, LLC ("Hilcorp") informed ENSTAR and other Alaska utility companies that Hilcorp would not be extending their existing contracts.[5] Hilcorp is the largest natural gas producer in Alaska, and ENSTAR's contract with Hilcorp currently provides approximately 85% of the natural gas volumes ENSTAR's Gas Sales Service customers ("Customers") require each year, and a majority of the deliverability.[6] With the contract set to expire on March 31, 2033, the Company must find alternative arrangements to replace this vitally important source of natural gas supply.[7] As the Commission knows, the Company has been actively exploring its options for several years.[8]

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[2] *Id.* ¶ 4.

[3] *Id.*

[4] *Id.* ¶ 5.

[5] *Id.*

[6] *Id.*

[7] *Id.*

[8] *Id.*

The proposed Project will address two critical needs for ENSTAR.[9] First, the new storage facility will help ensure that ENSTAR has adequate gas supply to meet its Customers' needs into the future.[10] With additional storage capacity, the Company will be able to purchase gas supply as it becomes available and then store those volumes for future customer use.[11] Given the gas supply challenges in Cook Inlet, having the ability to procure gas produced at any time—rather than scrambling to procure it "just in time"—will help ensure reliable, uninterrupted service to Customers.[12] In fact, a natural gas producer in the region has informed the Company that it is willing to increase production, but only if adequate storage is available in the market.[13] Second, the Project will ensure that ENSTAR has adequate deliverability and injectability to store and remove the gas and deliver it to Customers through the Company's distribution system when needed.[14]

The changing gas supply environment in Southcentral Alaska has led to a simple reality: ENSTAR must have additional storage to meet its Customers' needs.[15] Going forward, the Company will have only three possible sources of gas supply: (1) gas produced from the Cook Inlet; (2) deliveries of liquefied natural gas ("LNG"); and (3) gas from a new North Slope pipeline

[9] *Id.* ¶ 6.

[10] *Id.*

[11] *Id.*

[12] *Id.*

[13] *Id.*

[14] *Id.*

[15] *Id.* ¶ 7.

that will potentially be constructed as part of the Alaska LNG Project.[16] The extent to which ENSTAR will rely on each of these resources will depend on numerous factors, but in all three situations, one fact remains constant: ENSTAR will need additional storage to accommodate gas supply.[17] None of these three options will be possible without additional storage capacity.[18]

ENSTAR respectfully requests that the Commission consider this Petition on an expedited basis. ENSTAR could potentially need storage as early as the fourth quarter of 2026, which is less than one year away.[19] A natural gas production company in Alaska—BlueCrest Alaska Operating, Inc. ("BlueCrest")—has already committed to supplying ENSTAR with gas by the fourth quarter of 2026, but only if the Company has the ability to store those volumes (or use them immediately).[20] Otherwise, if ENSTAR does not have the necessary storage capacity, BlueCrest could lose its financing and could need to search for new sources of capital, all of which could cause further delay in the production of gas.[21] Additionally, the Company also will need new storage in 2027 so that it can receive new gas supplies.[22] Further, after ENSTAR executes its contract to acquire the depleted gas reservoir and associated facilities, the Company will need time to execute additional commercial agreements, including natural gas storage leases, a rig procurement agreement, surface leases, and arrangements for the procurement of long-lead

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[16] *Id.*

[17] *Id.*

[18] *Id.*

[19] *Id.* ¶ 8.

[20] *Id.*

[21] *Id.*

[22] *Id.*

items and materials.[23] For example, based on vendor input, ENSTAR will need six months to procure the pipe necessary to bring the Project in-service.[24] That means that if the Commission were to grant ENSTAR's request for an advance prudence determination by March 1, 2026, the Company will be able to receive the pipe by August, which will help ensure that the Project goes into service by the fourth quarter.[25] As another example, and also based on communications with vendors, ENSTAR will need approximately nine to ten months to procure the compressor and compressor skid necessary to make the Project fully functional.[26] Finally, obtaining an advance prudence determination on an expedited basis will facilitate ENSTAR's process of obtaining the additional approvals and leases from other Alaska agencies and entities, including the Alaska Oil and Gas Conservation Commission, the Department of Natural Resources, the Alaska Mental Health Trust, and Cook Inlet Regional Incorporated.[27]

Given all these factors, expedited consideration of this Petition is wholly appropriate, because it will help ensure that the Project moves forward on the necessary timeline.[28] To continue meeting its statutory obligation to serve its Customers with safe and reliable service, ENSTAR must act with great urgency.[29] Accordingly, the Company respectfully requests that

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[23] *Id.*

[24] *Id.*

[25] *Id.*

[26] *Id.*

[27] *Id.*

[28] *Id.* ¶ 9.

[29] *Id.*

the Commission issue an order granting the relief requested herein on an expedited basis, and specifically within 45 days of the filing of the primary Petition.

DATED this 12th day of January 2026, at Anchorage, Alaska.

By: _____

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ATTORNEYS FOR ENSTAR NATURAL GAS COMPANY, LLC

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	John M. Espindola, Chairman Steve DeVries Mark Johnston Robert M. Pickett John C. Springsteen
In the Matter of the Petition Filed by ENSTAR NATURAL GAS COMPANY, LLC for Advanced Determination of Decisional Prudence for Natural Gas Storage Project	Docket No. U-26-____

AFFIDAVIT OF JOHN D. SIMS

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

John D. Sims, being first duly sworn, deposes and says:

1. I am President of ENSTAR Natural Gas Company, LLC ("ENSTAR" or "Company"), Alaska Pipeline Company, LLC, and Cook Inlet Natural Gas Storage Alaska, LLC.

2. I am submitting this Affidavit in support of ENSTAR's Motion for Expedited Consideration of Petition for Advanced Determination of Decisional Prudence for Natural Gas Storage Project.

3. ENSTAR is submitting its Petition to request an advance determination of prudence for a proposed natural gas storage project ("Project"). The Project proposed in this proceeding represents a significant step in ENSTAR's long history of delivering safe, reliable service to the thousands of Alaska homes and businesses throughout its service territory.

4. ENSTAR proposes to acquire a depleted natural gas reservoir and associated facilities in the City of Kenai. The depleted reservoir site includes four existing wells along with other facilities, and the Company will install the major equipment upgrades necessary to ensure that the facility can reliably store, inject, and withdraw natural gas in accordance with federal and state engineering and design standards.

5. The Project is a necessary response to the significant and well-documented challenges that ENSTAR and other utilities currently face in procuring natural gas supply in Cook Inlet. In 2022, Hilcorp Alaska, LLC ("Hilcorp") informed ENSTAR and other Alaska utility companies that Hilcorp would not be extending their existing contracts. Hilcorp is the largest natural gas producer in Alaska, and ENSTAR's contract with Hilcorp currently provides approximately 85% of the natural gas volumes ENSTAR's Customers require each year, and a majority of the deliverability. With the contract set to expire on March 31, 2033, the Company must find alternative arrangements to replace this vitally important source of natural gas supply. As the Commission knows, the Company has been actively exploring its options for several years.

6. The proposed Project will address two critical needs for ENSTAR. First, the new storage facility will help ensure that ENSTAR has adequate gas supply to meet its Customers' needs into the future. With additional storage capacity, the Company will be able to purchase gas supply as it becomes available and then store those volumes for future customer use. Given the gas supply challenges in Cook Inlet, having the ability to procure gas produced at any time—rather than scrambling to procure it "just in time"—will help ensure reliable, uninterrupted service to Customers. In fact, a natural gas producer in the region has informed the Company

that it is willing to increase production, but only if adequate storage is available in the market. Second, the Project will ensure that ENSTAR has adequate deliverability and injectability to store and remove the gas and deliver it to Customers through the Company's distribution system when needed.

7. The changing gas supply environment in Southcentral Alaska has led to a simple reality: ENSTAR must have additional storage to meet its Customers' needs. Going forward, the Company will have only three possible sources of gas supply: (1) gas produced from the Cook Inlet; (2) deliveries of liquefied natural gas ("LNG"); and (3) gas from a new North Slope pipeline that will potentially be constructed as part of the Alaska LNG Project. The extent to which ENSTAR will rely on each of these resources will depend on numerous factors, but in all three situations, one fact remains constant: ENSTAR will need additional storage to accommodate gas supply. None of these three options will be possible without additional storage capacity.

8. ENSTAR respectfully requests that the Commission consider this Petition on an expedited basis. ENSTAR could potentially need storage as early as the fourth quarter of 2026, which is less than one year away. A natural gas production company in Alaska—BlueCrest Alaska Operating, Inc. ("BlueCrest")—has already committed to supplying ENSTAR with gas by the fourth quarter of 2026, but only if the Company has the ability to store those volumes (or use them immediately). Otherwise, if ENSTAR does not have the necessary storage capacity, BlueCrest could lose its financing and could need to search for new sources of capital, all of which could cause further delay in the production of gas. Additionally, the Company also will need new storage in 2027 so that it can receive new gas supplies. Further, after ENSTAR

executes its contract to acquire the depleted gas reservoir and associated facilities, the Company will need time to execute additional commercial agreements, including natural gas storage leases, a rig procurement agreement, surface leases, and arrangements for the procurement of long-lead items and materials. For example, based on vendor input, ENSTAR will need six months to procure the pipe necessary to bring the Project in-service. That means that if the Commission were to grant ENSTAR's request for an advance prudence determination by March 1, 2026, the Company will be able to receive the pipe by August, which will help ensure that the Project goes into service by the fourth quarter. As another example, and also based on communications with vendors, ENSTAR will need approximately nine to ten months to procure the compressor and compressor skid necessary to make the Project fully functional. Finally, obtaining an advance prudence determination on an expedited basis will facilitate ENSTAR's process of obtaining the additional approvals and leases from other Alaska agencies and entities, including the Alaska Oil and Gas Conservation Commission, the Department of Natural Resources, the Alaska Mental Health Trust, and Cook Inlet Regional Incorporated.

9. Given all these factors, expedited consideration of this Petition is wholly appropriate, because it will help ensure that the Project moves forward on the necessary timeline. To continue meeting its statutory obligation to serve its Customers with safe and reliable service, ENSTAR must act with great urgency. Accordingly, the Company respectfully requests that the Commission issue an order granting the relief requested herein on an expedited basis, and specifically within 45 days of the filing of the primary Petition.

FURTHER AFFIANT SAYETH NOT.

John D. Sims

SUBSCRIBED AND SWORN TO OR AFFIRMED before me, the undersigned notary, at Anchorage, Alaska, this 12th day of January, 2026, to which witness my hand and seal.

Notary Public, State of Alaska
My commission expires: November 1, 2029

CERTIFICATE OF SERVICE

I hereby certify that on January 12, 2026, a true and correct copy of the foregoing document was served by electronic mail on the following:

Jeffrey J. Waller
Office of the Attorney General
1031 W. 4th Avenue, Suite 200
Anchorage, Alaska 99501
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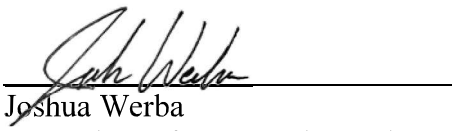


Joshua Werba
Supervisor of Rates and Regulatory

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	John M. Espindola, Chairman Steve DeVries Mark Johnston Robert M. Pickett John C. Springsteen
In the Matter of the Petition Filed by ENSTAR NATURAL GAS COMPANY, LLC for Advanced Determination of Decisional Prudence for Natural Gas Storage Project	Docket No. U-26-____

ENSTAR NATURAL GAS COMPANY'S PETITION FOR ADVANCED DETERMINATION OF DECISIONAL PRUDENCE FOR NATURAL GAS STORAGE PROJECT

AFFIDAVIT OF INNA B. JOHANSEN

AFFIDAVIT OF INNA B. JOHANSEN

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

Inna B. Johansen, being first duly sworn, deposes and says:

Introduction

1. My name is Inna B. Johansen. My business address is 5151 Fairbanks Street, Anchorage, Alaska 99503. I am the Vice President of Regulatory and Gas Supply for ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). I am appearing in this proceeding on behalf of ENSTAR and APC. For convenience, I will refer to ENSTAR and APC together as "ENSTAR" or the "Company." The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

2. I have been employed by ENSTAR in positions of increasing responsibility for over 18 years. Since 2015, I have led the Gas Supply and Budget & Strategic Planning departments. I assumed responsibilities for Gas Control operations in 2020 and management of transport customers in January 2022. In April 2024, I became the Vice President of Regulatory and Gas Supply. Prior to assuming my current position, I managed and worked in various individual departments within ENSTAR, including Finance, Marketing, Operations, and Regulatory. From 2013-2014, I held the position of Asset Manager at Southern Power Company ("SPC"), a subsidiary of Southern Company.

While at SPC, I worked with multiple electric utilities and wholesale power buyers by managing the physical, financial, contractual, and operational activities associated with power purchase agreements across multiple states. I hold a Bachelor of Arts in Finance from Kazakh State Academy of Business and a Master of Business Administration from Middle Tennessee State University Jennings A. Jones College of Business. My resume is attached as Exhibit IBJ-1.

3. I have testified before the Commission in Dockets U-07-084, U-18-004, U-18-024, U-22-081, U-25-013, U-25-019 and U-25-021 on behalf of ENSTAR.

4. The purpose of my affidavit is to support ENSTAR's request for an advance determination that the Company's decision to develop a natural gas storage facility (the "Project") is prudent, in the public interest, and consistent with the Company's obligations under the Alaska Public Utilities Regulatory Act. In particular, I will discuss ENSTAR's obligation to provide safe and reliable service to its Gas Sales Service customers ("Customers") and how ENSTAR meets that supply today. I will also discuss Customers' gas demand; ENSTAR's gas supply resources; the assessments of options supporting the decision to develop the Project; the new gas storage solution; cost recovery; and the manner in which ENSTAR plans to report progress of the Project development to the Commission.

5. I, or those under my direct supervisions, have reviewed all of the source material referenced in the citations in this affidavit. The references and quotes are true and correct representations or reproductions of those materials.

ENSTAR's Obligations to Customers

6. ENSTAR provides natural gas service, including the provision and sale of gas, to more than half of the population of Alaska. These customers are the families, businesses, and critical facilities behind approximately 156,000 meters in Southcentral Alaska, from Houston all the way down to the Homer Spit. Over 142,000 of those meters are on residential homes, and the rest of the meters provide service to large and small commercial businesses throughout ENSTAR's certificated service area. In 2024, ENSTAR also accepted the role of gas supplier to Alaska Electric and Energy Cooperative, Inc. and Homer Electric Association, Inc. (collectively, "HEA"), providing Gas Sales Service to the Company's fellow Southcentral Alaska utility.

7. The Company's terms of service are dictated by state statutes and ENSTAR's tariff, which is subject to Commission regulation. The following are examples of the provisions that describe ENSTAR's obligation to serve Customers:

- Alaska Statute 42.05.291(a) requires that ENSTAR "furnish and maintain adequate, efficient and safe service and facilities. This service shall be reasonably continuous and without unreasonable interruption or delay."

- Alaska Statute 42.05.371 states that the "terms and conditions under which a public utility offers its services to the public shall be governed strictly by the provisions of its currently effective tariffs."

- ENSTAR's tariff Section 801 states that "The Company will use reasonable diligence to supply steady and continuous service, but does not guarantee the service against irregularities or interruptions. In case of shortage of supply and during the period of such shortage, the Company will apportion its available supply of gas among all Customers in the most reasonable manner possible. The supply of gas for Commercial Use may be curtailed or discontinued at any time when it shall be necessary to do so in order to supply Residential Use Customers."

8. As John D. Sims discusses in his affidavit, the Company's methods and practices for meeting its obligation to customers have evolved over the past few decades. For many decades, ENSTAR benefited from multi-year contracts that met all of Customers' volumetric and deliverability needs. However, the early 2000s were marked by the departure of prominent Cook Inlet producers; reduced investment in gas production infrastructure; and producers' reluctance to negotiate long-term, firm gas contracts that met Customers' complex demands. As of January 1, 2009, ENSTAR no longer had a full requirements supplier. Instead, ENSTAR had a portfolio of gas sale agreements that together met the annual and peak day needs of its Customers. This instability and producers' unwillingness to commit to firm, long-term gas supply agreements left ENSTAR and its fellow Cook Inlet utilities searching for secure gas supply.

9. In 2011, the Cook Inlet started facing supply constraints, resulting in ENSTAR purchasing gas on a pseudo-spot market at prices exceeding $20 per thousand cubic feet ("Mcf") during peak heating season. The lack of peak deliverability in the marketplace was also a key motivation for the creation of the first publicly regulated natural gas storage utility in Alaska, which is owned by ENSTAR's affiliate, Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"). CINGSA commenced operations in 2012. Also, in 2011 and 2012, after Chevron Corporation and Marathon Oil Corporation exited the Cook Inlet gas market, Hilcorp Alaska, LLC ("Hilcorp") acquired all of the natural gas production, pipeline and storage assets that those two producers historically utilized to provide all-requirements gas supply service to ENSTAR. Shortly after approvals of these

acquisitions, ENSTAR contracted with Hilcorp and other producers to meet its remaining uncovered gas demand through March 31, 2018. With the arrival of Hilcorp, and the inception of CINGSA, we had a period of relatively stable gas prices and availability. To support continued reliability, ENSTAR has attempted to procure natural gas from a variety of gas pools from a diversified portfolio of natural gas suppliers. In April 2022, however, Hilcorp announced to all of its gas supply customers that it would not be extending firm supplies beyond existing contracts. This announcement marked a new chapter of gas delivery in the Cook Inlet.

10. Today, we meet our obligations by negotiating year-round to ensure a reliable supply, utilizing a variety of different natural gas contracts, fully utilizing CINGSA, and ensuring we have a robust transmission system. Our portfolio includes a firm contract with Hilcorp that meets approximately 85% of customer annual demand (expiring in March 2033). On May 1, 2025, Hilcorp acquired Vision Resources, LLC ("Vision"). As part of this acquisition, Vision's contract with APC was assigned to Hilcorp and will remain in effect for the remainder of its term that expires on March 31, 2028. The remaining gas demand is met through gas supply agreements with Furie Operating Alaska, Inc. ("Furie") and BlueCrest Alaska Operating LLC ("BlueCrest") as well as utilization of gas storage service received from CINGSA. Additionally, ENSTAR continues to work with producers to secure additional gas volumes as contracts continue to step down in volumes.

11. Once natural gas enters the ENSTAR transmission system, we have to ensure that we can move it from a variety of delivery points to end users from Houston to Homer. ENSTAR

operates and maintains its transmission and distribution systems and supporting infrastructure to meet or exceed standards set by federal regulation and maximize reliability and customer safety. ENSTAR also pays special attention to pipeline pressures during periods of prolonged cold temperatures to identify potential at-risk areas and ensure that we continue to serve all parts of our service area regardless of the temperature.

12. Going forward, ENSTAR will have to make significant changes to its traditional gas procurement strategies to ensure continued, reliable service to Customers. As ENSTAR has demonstrated throughout its history, the Company will diligently pursue solutions to satisfy its service obligations. The Company is proud of its successful efforts and will continue to provide the safe and reliable service Customers need.

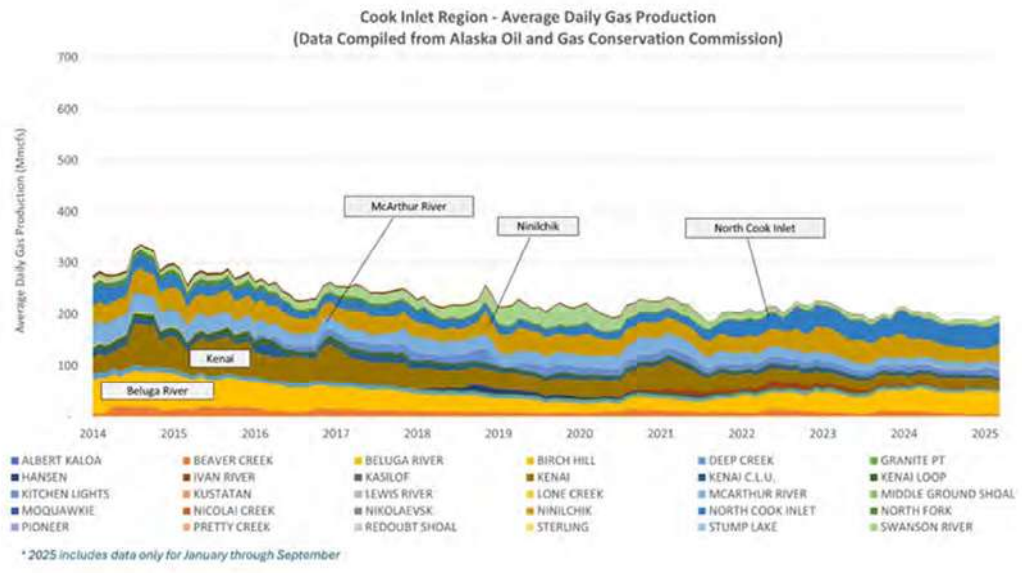
13. Since 1961, when the first gas molecule was delivered to a Customer, that gas has been locally sourced and placed into the pipeline system at a rate that met Customer demand. This was possible due to a large industrial gas user and gas export operations that maintained a relatively large and steady volume of gas on the system. In light of that market condition, gas contracts were structured with sufficient flexibility to maintain ENSTAR's volumetric and deliverability requirements.

14. As the large pools of gas began to deplete, production became more expensive as meeting large daily demands became more challenging. This increased production cost resulted in the large industrial gas user and gas exports dropping out of the Cook Inlet market. Suddenly, there was not sufficient system supply to meet the variability and volatility of ENSTAR Customers' demand.

15. To replace declining gas field production and meet increased deliverability needs, Chevron developed gas storage capacity in the Swanson River and Pretty Creek units in 2001 and 2004. In 2006, Marathon commissioned its Kenai gas storage facility in support of its contractual obligations for the supply of utility gas during the winter. However, the development of storage operations was not enough to offset rapidly declining production and deliverability in the Cook Inlet region. For this reason, CINGSA storage was constructed in 2012 to allow ENSTAR and other regional gas users to purchase Cook Inlet gas on a flatter production profile and store volumes that exceeded demand in storage for later use.

16. The decline in Cook Inlet daily production deliverability as presented in Figure 1 continues to drop from approximately 300 million cubic feet per day ("MMcfd") in 2015 to approximately 200 MMcfd in 2025. The data in Figure 1 below comes from the Alaska Oil and Gas Conservation Commission.

Figure 1 – Cook Inlet Average Daily Gas Production



17. Currently, despite Hilcorp's ability to utilize all of its gas storage fields to meet its contractual gas supply obligations, satisfying ENSTAR's gas delivery profile continues to be challenging during peak cold winter months. Once ENSTAR's contract with Hilcorp expires, 85% of the volume and a majority of the deliverability that ENSTAR receives under its current Hilcorp contract will need to be replaced.

18. The additional gas volume necessary to meet future requirements will come from a variety of other producers in the Cook Inlet, along with non-local gas from the liquefied natural gas ("LNG") markets or the North Slope of Alaska via the proposed Alaska LNG project. The gap in deliverability will have to be filled from additional storage, as none of the other gas sources are capable of providing the deliverability needs for Customers.

The level of storage service and operational characteristics that ENSTAR requires also are not currently available to the Company in Cook Inlet. For this reason, ENSTAR seeks to develop storage that will be sufficient to store the amount of gas that ENSTAR requires, at withdrawal and injection rates that meet our Customers' demand under current and future gas supply market conditions.

ENSTAR Customer Demand

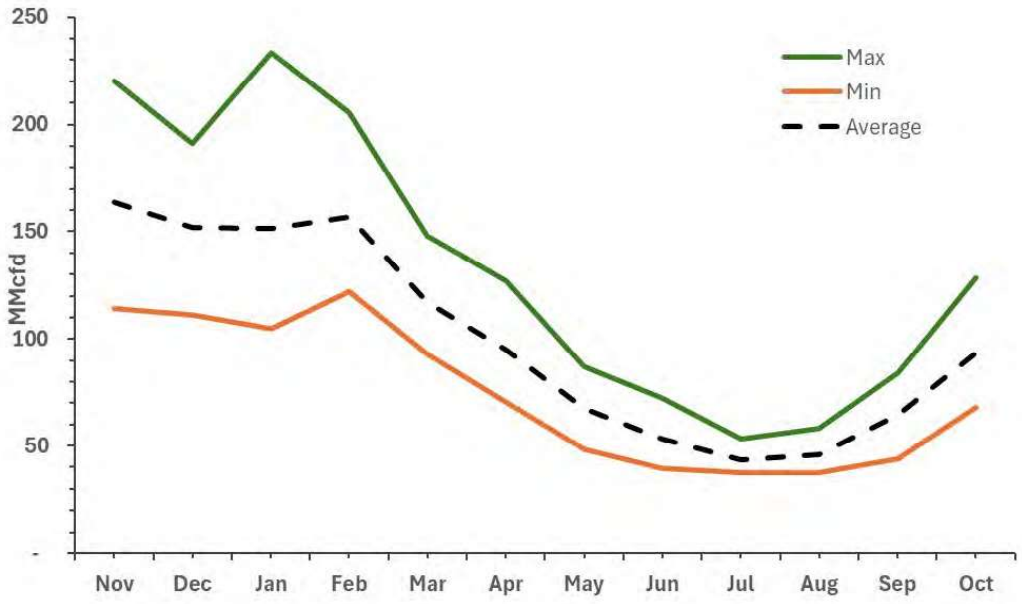
19. ENSTAR assesses its Customer demand using two distinct parameters. The first is the amount of gas required by Customers on an annual basis. The second is the amount of natural gas required to meet Customer demand on a daily basis.

20. Depending on the weather, ENSTAR's annual demand fluctuates between 34 and 41 billion cubic feet ("Bcf"). While ENSTAR's historical average annual demand has consistently stayed within 33-34 Bcf, the addition of HEA as a Customer in 2024 added an additional 4 Bcf to ENSTAR's overall annual demand requirements.

21. ENSTAR Customers' annual demand requirements are very difficult to identify with precision. Customer demand is highly weather-sensitive. Customer demand is not only extremely seasonal but also highly variable. Customers' daily demand experiences significant fluctuations over the course of the year, which makes this one of the most difficult challenges in meeting ENSTAR's statutory obligation to provide reasonably continuous service to our Customers. In addition, ENSTAR must be prepared to meet not only seasonal changes in demand but also varying demand within each season. Figure 2 below is based on the actual observed daily loads of ENSTAR's Customers during

November of 2024 through October of 2025 and it demonstrates how seasonal weather changes alter the amount of gas ENSTAR's Customers can consume throughout the year. The most variability in daily loads is observed during the peak heating season of November through February when the daily loads can double depending on the changing weather.

Figure 2 – Total System Average Daily Load (November 2024 – October 2025)



22. Understanding and analyzing key demand drivers and their potential impact on ENSTAR's ability to provide gas services is vital to the planning process. The Company has to be prepared to respond quickly to customer needs at all times. ENSTAR has to develop and maintain gas distribution infrastructure and a gas supply portfolio sufficient to respond quickly to customer needs at all times.

23. ENSTAR utilizes historical data as a baseline to determine its Customer demand. To build forecasts, ENSTAR considers a range of scenarios and assesses a wide spectrum of potential outcomes. ENSTAR uses an internally developed gas supply model to assess and forecast Customers' demand and solve natural gas supply and storage optimization questions ("Gas Supply Model"). The Gas Supply Model considers the following variables:

- demand data, such as customer count forecasts and consumption by customer type (*e.g.*, residential, commercial or power and industrial);
- base and heating load variables;
- Customer conservation trends;
- weather data, including minimum, maximum, and average temperatures; and
- daily gas demand.

24. The Gas Supply Model allows ENSTAR to test various weather patterns and analyze its effects upon demand.

25. The analysis begins with a forecast of the total number of Customers. ENSTAR provides approximately 156,000 Customers with natural gas service across the Anchorage, Mat-Su Borough, Kenai Peninsula and Homer areas. ENSTAR's Customers include residential, commercial, and power and industrial categories. Table 1 below shows the number of Customers by area by class as of November 2025.

Table 1 – ENSTAR's Customers as of November 30, 2025

	All Customers				
	Anchorage	Kenai Peninsula	Mat-Su	Homer	Total
G1 Residential	87,386	14,014	33,882	2,626	137,908
G2 Residential	3,156	290	688	50	4,184
G3 Residential	445	38	125	10	618
G4 Residential	9	-	1	-	10
	90,996	14,342	34,696	2,686	142,720
G1 Non-residential	3,963	1,049	1,896	358	7,266
G2 Non-residential	1,359	270	310	40	1,979
G3 Non-residential	2,344	376	456	50	3,226
G4 Non-residential	796	77	131	5	1,009
Pwr & Ind. Sales	-	1	-	-	1
	8,462	1,773	2,793	453	13,481
G1 Sales	91,349	15,063	35,778	2,984	145,174
G2 Sales	4,515	560	998	90	6,163
G3 Sales	2,789	414	581	60	3,844
G4 Sales	805	77	132	5	1,019
Pwr & Ind. Sales	-	1	-	-	1
	99,458	16,115	37,489	3,139	156,201

26. Over the last ten years, ENSTAR's Customer base has grown at a rate of approximately 1% per year. ENSTAR expects that it will continue to see this level of Customer growth in future years, thus, the forecast of Customer numbers assumes the same growth rate.

27. After ENSTAR estimates the number of Customers that it anticipates serving in the future, the Company forecasts the natural gas use of each Customer. Each Customer category exhibits different demand patterns, such as reactivity to colder temperatures,

size of heating load versus base load, and conservation trends. ENSTAR analyzes these variables and incorporates them into its per-customer usage forecasts.

28. The next step is to assess the historical weather and prepare the weather forecast used for planning. The forecast is used to calculate the expected demand by combining use per Customer with number of Customers. To understand the impact of weather on demand, ENSTAR models Customer demand based on the actual weather scenarios experienced in the Company's service territory. To account for recent weather trends, the analysis incorporates the most recent 20 years of daily weather data from the National Oceanic and Atmospheric Administration ("NOAA"). NOAA's most recent 10-year average weather serves as the base weather forecast to prepare the annual average demand forecast ("Normal Demand"). In addition to calculating Normal Demand, the demand forecast is calculated using the actual daily weather during the coldest and warmest years observed over the last 20 years.

29. To evaluate system resilience under varying demand conditions, ENSTAR created a weather scenario that tests cold, normal and warm years through 2045 where gas supply is coming from different sources (the "Various Weather Scenario"). In the Various Weather Scenario, a cold year is followed by two consecutive warm years. This approach examines: (1) how demand and storage requirements shift during transitions from cold to warm conditions, and (2) whether the system can handle two warm years in a row. Historically, during warm years, Customers can use up to 10% less gas compared to a year with normal weather. ENSTAR purchases most of its gas through firm gas supply

commitments that are designed to cover, at a minimum, Normal Demand. This misalignment between reduced Customer demand and firm "take-or-pay" gas supply purchases could result in a large gas surplus. Until ENSTAR is able to readjust its gas procurement commitments, ENSTAR will have to utilize its storage assets to manage this unplanned excess supply. Since it takes at least a year to adjust its gas procurement commitments, using two warm years in a row provides a more accurate assessment of overall gas storage requirements.

30. ENSTAR experienced this particular issue in 2016 when Southcentral Alaska experienced record-breaking warm temperatures during 2014 through 2016. This weather pattern resulted in a significant reduction in ENSTAR's gas demand, causing ENSTAR to exceed its contractual storage capacity in CINGSA and to implement other supply reduction measures to align the reduced demand with gas supply that the Company was committed to purchase under its firm "take or pay" gas supply agreements. ENSTAR had to cancel low-priced gas purchases under all interruptible agreements in its portfolio, delay firm gas deliveries under Hilcorp's contract, and transfer some if its excess storage volume to another CINGSA firm service customer. Once the cold weather resumed in the winter of 2017, ENSTAR finally was able to bring its storage inventory down to a more acceptable level.

31. Experiencing colder than normal temperatures can have an opposite effect to how ENSTAR manages its gas supply and storage resources. Increased demand during cold

years can result in premature depletion of storage inventory in CINGSA requiring ENSTAR to seek additional gas supply resources on the market.

32. The three weather inputs used in the Various Weather Scenario reflect the actual daily weather experienced during the following years:

- 2004 - 9,556 heating degree days ("HDDs") were experienced and these HDDs are used to model average weather that will result in Normal Demand ("Normal Year");
- 2019 - 8,177 HDDs were experienced and were the fewest number of HDDS over the last 20 years ("Warm Year"); and
- 2012 - 11,190 HDDs were experienced and were the highest number of HDDs over the last 20 years ("Cold Year").

33. From the Various Weather Scenario, we can forecast and reliably project Customer demand for almost any weather event or season. For its analysis, ENSTAR used the following sequence: Normal Year, Cold Year, Warm Year, Warm Year, Normal Year. This combination of weather inputs allows ENSTAR to assess Customers' demand as it transitions from one type of weather to another. Table 2 below lists out the impact of the different weather inputs and the potential annual demand projected under each weather scenario until 2045.

Table 2 - Estimated Annual Demand Based on Various Weather Scenario

Year	Weather Inputs	Estimated Demand, Bcf	Annual Difference, Bcf	Annual Difference, %
2025	Actual	37.64	0.00	
2026	Normal	38.19	0.55	1.47%
2027	Normal	38.28	0.09	0.23%
2028	Cold	42.23	**3.95**	**10.32%**
2029	Warm	34.91	**-7.31**	**-17.32%**
2030	Warm	34.84	-0.07	-0.20%
2031	Normal	38.39	**3.54**	**10.17%**
2032	Normal	38.43	0.04	0.10%
2033	Normal	38.46	0.04	0.09%
2034	Normal	38.54	0.08	0.21%
2035	Cold	42.54	**4.00**	**10.38%**
2036	Warm	35.17	**-7.37**	**-17.33%**
2037	Warm	35.25	0.08	0.21%
2038	Normal	38.86	**3.61**	**10.24%**
2039	Normal	38.94	0.08	0.20%
2040	Normal	39.01	0.08	0.20%
2041	Cold	43.03	**4.02**	**10.31%**
2042	Warm	35.62	**-7.41**	**-17.22%**
2043	Warm	35.70	0.08	0.22%
2044	Normal	39.33	**3.63**	**10.16%**
2045	Normal	39.41	0.08	0.20%

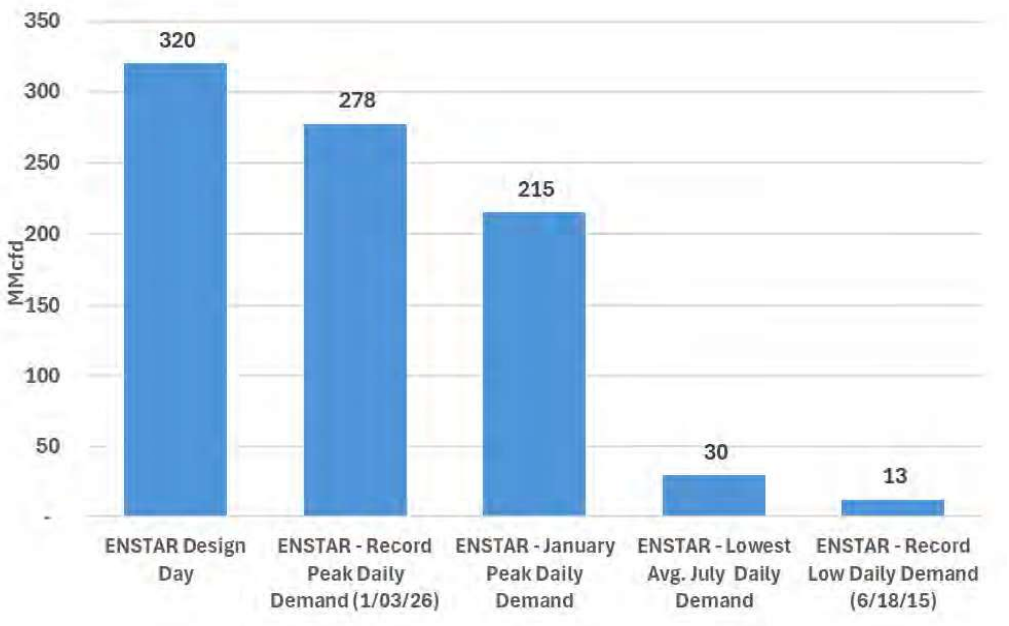
34. The modeling shows that on an annual basis, these variations in temperature can result in ENSTAR needing to procure significantly different volumes of gas each year (presented in the column labeled Estimated Demand, Bcf), which makes contracting for these supplies challenging for local producers and ENSTAR. Depending on the weather, ENSTAR forecasts that during the transition from a Warm Year to a Cold Year, the annual demand may fluctuate by more than 7 Bcf or a 17% variation between 34.84 and 42.24 Bcf. Transitioning from a Normal Year to a Cold Year or from a Normal Year to a Warm Year can increase or decrease Customer demand by approximately 4 Bcf.

35. The Various Weather Scenario presented in Table 2 was also used to estimate ENSTAR's storage requirements for the next 20 years under three distinct gas supply options. In its storage requirements analysis, ENSTAR assumed secure delivery of Cook Inlet gas from 2025 through early 2033 ("Cook Inlet Deliveries"), transitioning fully to LNG imports from 2033 to 2038 ("LNG Deliveries"), followed by North Slope pipeline deliveries from 2039 to 2045 ("NS Pipeline Deliveries"). The planning ranges for each of the gas supply options were developed for analysis only and are not representative of the actual timeframes of Cook Inlet transitioning to LNG and Pipeline gas deliveries. As presented in Table 2, ENSTAR applied the same sequence of weather inputs to assess each gas supply option.

36. Similar to the annual demand, Customers' daily demand is also significantly impacted by the number of HDDs that ENSTAR experiences. As Figure 3 shows, ENSTAR must be prepared to meet the daily demand potential of up to 320 MMcfd, although the peak demand during a typical winter day in January, which tends to be the coldest month, is more commonly around 215 MMcfd. In the summer months, this number can be as low as 30 MMcfd. To further demonstrate the range in daily Customers' demand fluctuations Figure 3 demonstrates ENSTAR's highest daily gas demand of 278 MMcfd experienced as recently as January 3, 2026, and the lowest daily demand of 13 MMcfd recorded on June 18, 2015. While ENSTAR's normal load has a seasonal swing of 5 to 1, ENSTAR's gas supply portfolio must reliably meet customer needs during peak days when demand

can push the swing to 12 to 1 or greater. Figure 3 below shows the difference in daily gas demand for ENSTAR.

Figure 3 – ENSTAR's Daily Gas Demand Variability

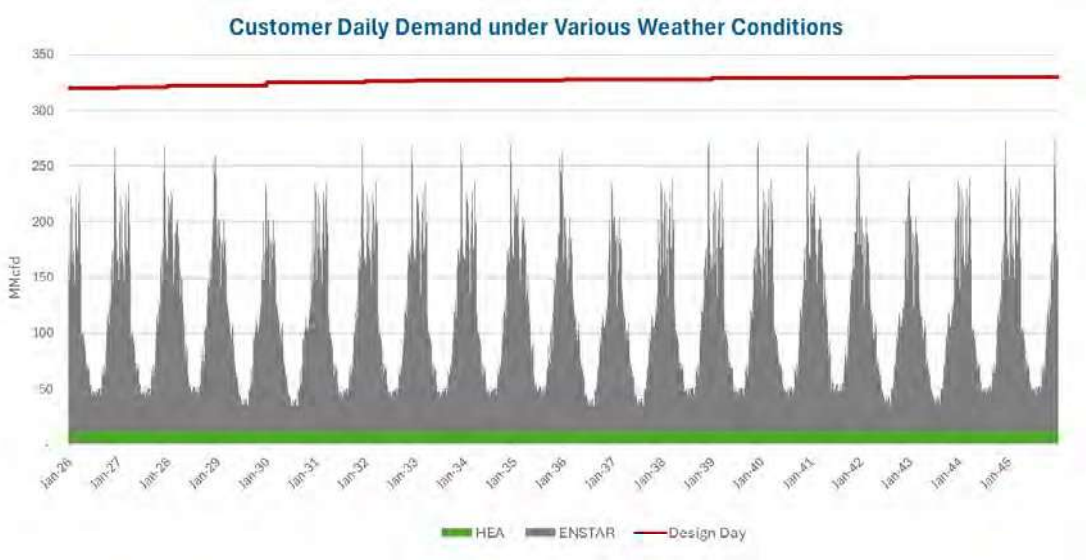


37. 320 MMcfd represents ENSTAR's "design day" peak requirements, or the highest possible rate of deliverability that could be experienced on the system. ENSTAR uses the concept of a design day to determine its highest gas demand. A design day is an estimate of gas usage that is representative of a utility's highest-demand day. ENSTAR determines its design day using research conducted by consultants with Marquette Energy Analytics, LLC. To determine its design day, ENSTAR uses the 1-in-30 years wind-adjusted design day temperature of -23.7° F, which yields 88.7 HDDs.

38. The fluctuation in daily demand is now impossible for any Cook Inlet producer to supply and has been unavailable for ENSTAR to procure for more than 20 years. Figure 4 below

details Customers' forecasted daily demand from 2026 through 2045 and highlights the enormous burden placed on ENSTAR to meet these fluctuations. The red line in Figure 4 represents Customers' requirements on the coldest day on record over the last 30 years. The data in Figure 4 represents the expected daily loads used in the calculation for future storage requirements.

Figure 4 – Forecasted Customers' Daily Demand (2026-2045)



Gas Supply Resources

39. ENSTAR manages gas supply procurement on a system-wide basis. Supply options include both firm and non-firm natural gas supplies. ENSTAR also uses its transportation agreement with Harvest Alaska, LLC ("Harvest") and storage services in CINGSA to manage its gas supply.

40. Currently, and as described in part above, ENSTAR has gas supply contracts with Hilcorp (including the former Vision contract), Furie, and BlueCrest, but Hilcorp's contract

supplies a vast majority of the gas for our Customers. These contracts provide for a combination of firm and interruptible volumes in an effort to secure as much gas as reasonably possible at a reasonable cost for Customers. While this is not a new strategy for gas procurement, one thing that has shifted is that new gas supply contracts now accommodate producers' ability to supply gas, rather than ENSTAR's capacity to purchase gas, which is a further indication of the market's decline.

41. ENSTAR serves daily Customer demand by executing firm gas supply contracts with producers that incorporate deliverability provisions to meet the Company's need. For example, the Amended and Restated Gas Sale and Purchase Agreement between Alaska Pipeline Company and Hilcorp Alaska, LLC ("Amended APL-14"), which is set to expire in 2033, includes a Firm Annual Contract Quantity ("ACQ") of 25 Bcf and a Firm Daily Contract Quantity ("DCQ") that fluctuates seasonally. Amended APL-14 also contains provisions for ENSTAR either to increase or decrease the Firm ACQ and the Firm DCQ when the options are timely exercised. These options include Daily Call gas, Needle Peak Call, and Turn-Up and Turn-Down Options. ENSTAR negotiated for each of these provisions to ensure that the Amended APL-14 provided the flexibility, and therefore the reliability, needed to meet a majority of Customers' needs.

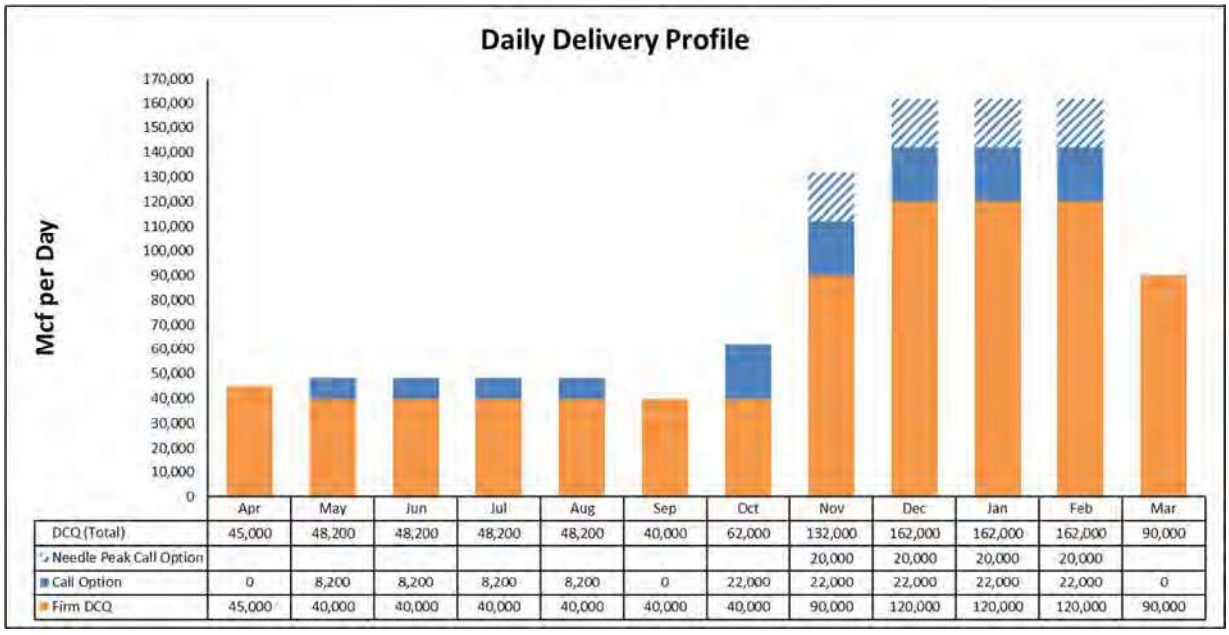
42. Daily Call Option provides gas volumes of 4 Bcf in each Contract Year. Daily Call Option Gas is available for purchase at ENSTAR's sole option.

43. ENSTAR retained its ability to purchase an additional 20 MMcfd of Needle Peak Call Option Gas on 25 days to manage extreme peaks in gas usage during the winter.

44. ENSTAR has an ability to either decrease Firm Gas purchases by up to 2.19 Bcf ("Turn-Down Option") or increase its Firm Gas purchases by up to 3 Bcf ("Turn-Up Option") on an annual basis provided notice is given 24 months prior to the start of the Contract Year when such volume adjustments will be in effect.

45. Figure 5 below demonstrates the delivery profile available to ENSTAR under Amended APL-14, with daily volumes ranging between 40 MMcfd and 162 MMcfd depending on the season and temperature. This delivery profile requires Hilcorp to increase its gas deliveries by approximately 12 Bcf during the months of October through March.

Figure 5 – Hilcorp APL-14 Daily Delivery Profile



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
DCQ (Total)	45,000	48,200	48,200	48,200	48,200	40,000	62,000	132,000	162,000	162,000	162,000	90,000
Needle Peak Call Option								20,000	20,000	20,000	20,000	
Call Option	0	8,200	8,200	8,200	8,200	0	22,000	22,000	22,000	22,000	22,000	0
Firm DCQ	45,000	40,000	40,000	40,000	40,000	40,000	40,000	90,000	120,000	120,000	120,000	90,000

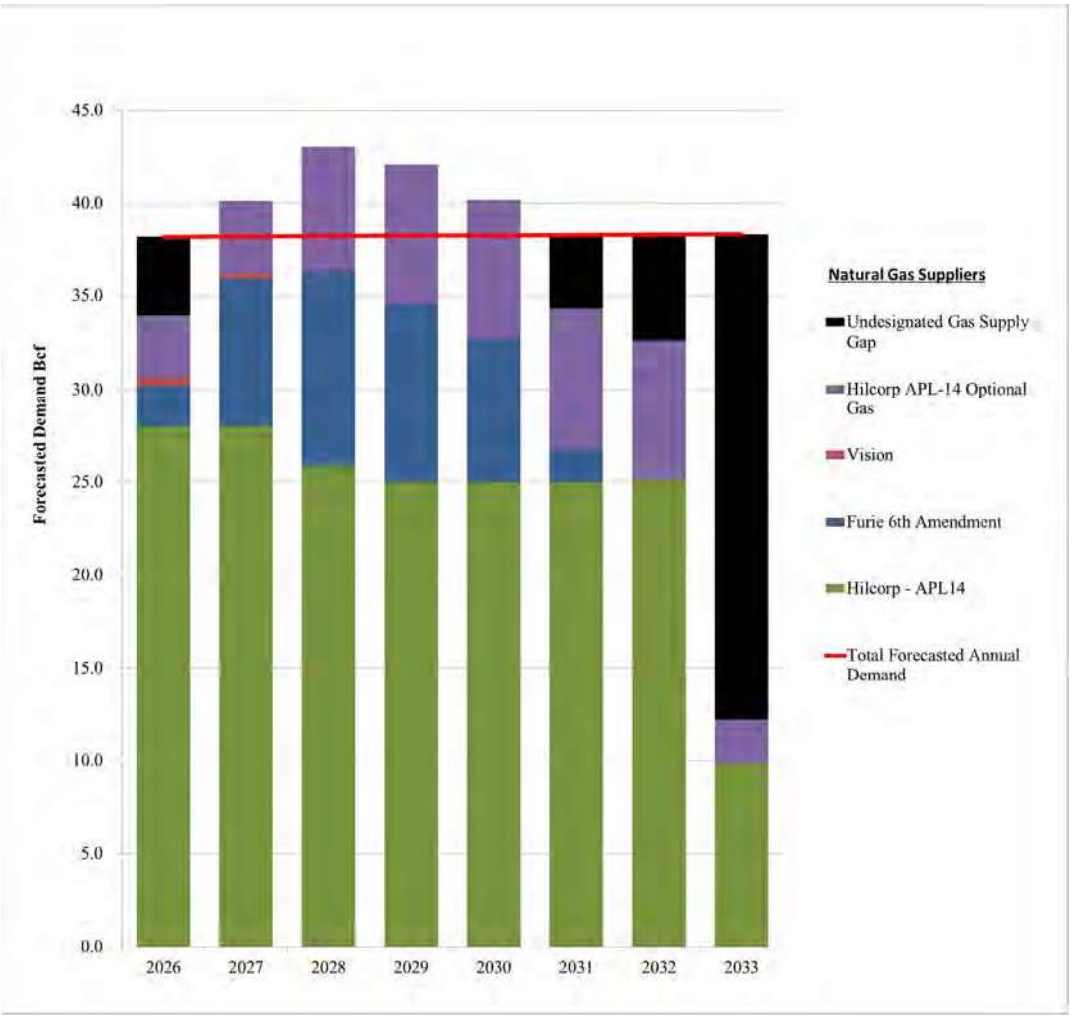
46. Under the Sixth Amendment to the Gas Sales Agreement with Furie, Furie committed to provide approximately 32 Bcf of firm gas between April 1, 2026, and March 31, 2031 ("Sixth Amendment"). Each year, the firm deliverability fluctuates between 8.1 MMcfd

and 29.5 MMcfd based on the results of Furie's drilling program. The remaining firm volumes under the Vision contract are set at 0.4 Bcf in 2026 and 0.3 Bcf in 2027, with the daily deliverability set at 1 MMcfd. The Sixth Amendment and the Vision contract both provide ENSTAR with the right to purchase any additional available production in excess of firm commitments. To take advantage of this potential newly developed production, as well as additional potential production from BlueCrest discussed in the affidavit of Mr. Sims, ENSTAR will need to secure sufficient storage capacity to store any excess gas for future use.

47. Each producer satisfies their obligations for deliverability in a different manner. Hilcorp combines the pressures achieved through additional well work and the drilling of new wells, along with Hilcorp's proprietary storage fields, to meet its deliverability obligations. Furie and BlueCrest, which have no proprietary storage, must rely on whatever deliverability rates are experienced after the completion of well work or the drilling of new wells. As a result, it is nearly impossible to predict and makes it difficult for these small producers to commit on a firm basis to high rates of deliverability. This is why the level of service provided by these producers is significantly lower than that of Amended APL-14.

48. Figure 6 below demonstrates ENSTAR's contracted supply and demand forecast for 2026 through 2033. The current firm gas supply agreements cover the period through March 31, 2033. The red line represents ENSTAR's estimated average annual demand under Normal Weather.

Figure 6 – ENSTAR's Estimated Supply and Demand Forecast for 2026-2033



49. Figure 6 demonstrates that ENSTAR still has an undesignated gas supply gap in 2026, which the Company expects to meet with non-firm gas purchases. Starting in 2027, given Normal Weather, ENSTAR anticipates a surplus when gas supply purchases will exceed customer demand under normal conditions. The surplus is projected to continue to accumulate through the end of 2029, creating an accumulated balance of 12 Bcf of gas. In addition to current gas supply commitments identified in Figure 6 above, ENSTAR

has an interruptible gas supply agreement with BlueCrest. Under this agreement BlueCrest committed to drill up to three new wells with new deliveries of gas commencing in the second half of 2026. The volumes under this gas supply agreement fluctuate between 5 to 20 Bcf depending on the number of drilled wells and drilling results.

50. ENSTAR does not have sufficient storage capacity to store an additional gas volume of 12 Bcf plus the new gas production it anticipates to purchase from BlueCrest. ENSTAR currently has two firm gas storage agreements with CINGSA: (1) an Initial Firm Storage Service ("FSS") Agreement that provides for 8.775 Bcf of gas storage; and (2) an Expansion FSS Agreement that provides for 2 Bcf of gas storage. In addition to these two agreements, HEA assigned its Initial FSS capacity of 0.125 Bcf to ENSTAR through the end of March 31, 2031. The total volume under these three agreements is 10.9 Bcf. Each year, ENSTAR utilizes a majority of its firm storage capacity to manage its gas supply purchases and deliver gas to its Customers. Over the last ten years, ENSTAR's monthly storage inventory fluctuated between 4 and 9 Bcf depending on various factors, such as weather, gas purchases, and customer demand. In addition, each year the inventory also fluctuates on a monthly basis reaching 8 to 9 Bcf during the August to September period and dropping to 4 to 5 Bcf during the end of withdrawal season in April and May. ENSTAR also typically leaves approximately 2 Bcf of storage volume unfilled to be able to respond to warm years when gas that is procured is not used to meet immediate demand. In addition to utilization of storage capacity, ENSTAR cycles

approximately 4 to 5 Bcf of gas per year by injecting and withdrawing gas to manage its gas supply commitments. The actual annual amounts of injections and withdrawals fluctuate depending on the weather, gas purchases, and customer demand. Starting in December 2024, ENSTAR also began utilizing Expansion FSS service (2 Bcf of gas storage). ENSTAR injected 1.3 Bcf of gas during the period of December 2024 to November 2025. The majority of this gas was used as an emergency storage service to cover record peak demand experienced on ENSTAR's system in December 2025 and January 2026. The daily usage of CINGSA's services demonstrates that ENSTAR is optimizing its storage service in CINGSA and does not have excess capacity to store an additional 12 Bcf or more of gas.

51. After incorporating the daily and annual Customer demand and supply into the Gas Supply Model, ENSTAR generated an assessment of demand compared to existing deliverability resources under the existing gas supply and storage service agreements using multiple weather scenarios. A Normal Demand case and the Various Weather Scenario (as previously discussed) were compared to existing storage rights in CINGSA on a peak day and the use on an annual basis. For both cases, the requirements for storage service exceed current storage resources over the next 20 years.

52. ENSTAR needs to obtain additional storage before the Hilcorp contract expires in 2033. The need for additional storage could begin as early as the fourth quarter of 2026. BlueCrest has committed to having natural gas available for ENSTAR by then, but only if the Company has the ability to use or store the gas. If ENSTAR is not able to meet that

deliverable, it is my understanding that BlueCrest could lose its financing and could need to search for new sources of capital, all of which would cause further delay in the production of gas. Mr. Sims also discusses this issue in his direct affidavit.

53. In addition, as previously discussed, ENSTAR needs additional storage services in 2027 so that it can manage the new gas supplies it expects to receive from Furie under the Sixth Amendment. Figures 7 and 8 below demonstrate the additional gas storage requirements ENSTAR anticipates to see during Cook Inlet Deliveries phase.

Figure 7 – Storage Volume Requirements during 2026-2033 (Cook Inlet Deliveries)

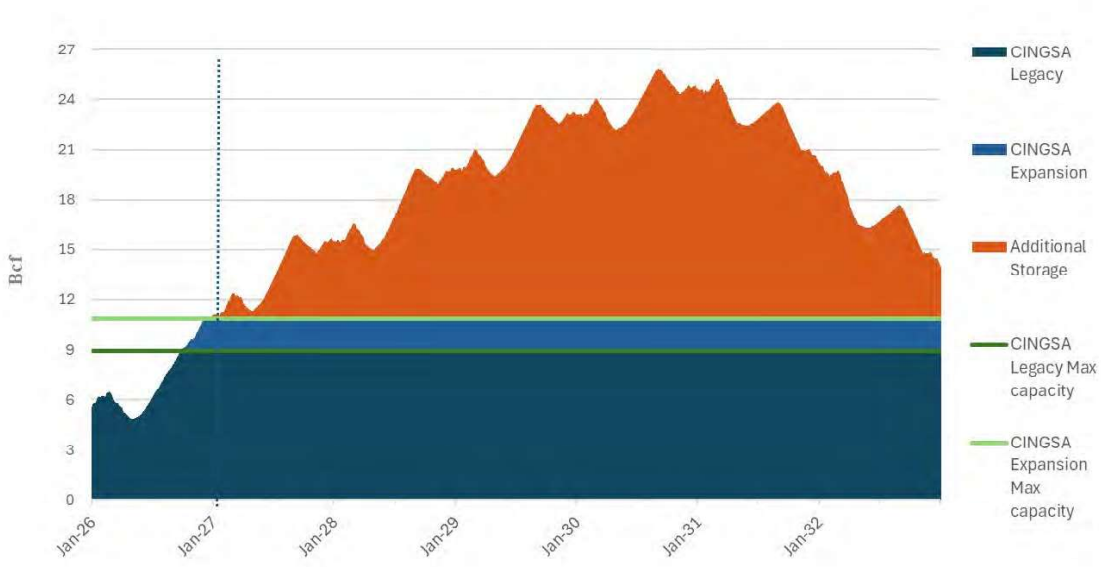
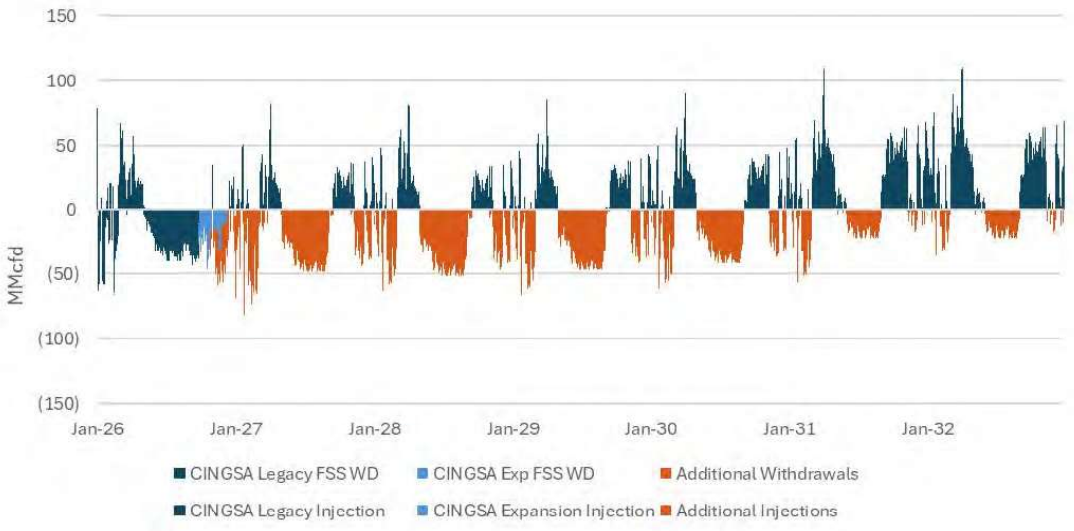


Figure 8 – Storage Daily Injections and Withdrawals Requirements during 2026-2033 (Cook Inlet Deliveries)



54. The area highlighted in orange in Figures 7 and 8 represents ENSTAR's additional storage requirements for volume, daily injection and withdrawal under the Normal Demand case for 2026 through 2033. ENSTAR projects an additional storage volume requirement of up to 15 Bcf. This includes gas supply purchases surplus of 12 Bcf that I discussed above and additional gas ENSTAR anticipates to secure during this timeframe.

55. When gas supply agreements with Cook Inlet producers expire, ENSTAR expects to fill the gap in annual volumes by bringing imported LNG to the region, and potentially by contracting to purchase gas produced on the North Slope. To manage these new gas supply sources efficiently, ENSTAR will require significant amounts of additional storage capable of providing adequate volume, injection, and withdrawal capacity.

56. Depending on the availability of Cook Inlet supplies, ENSTAR is preparing to import gas as early as 2030, but no later than 2032 to meet local utility demand. The LNG import delivery profile presents a unique and different challenge as far as how ENSTAR can utilize LNG to meet local demand. The safest time to import LNG occurs in the spring, summer, and fall months, when the existence of ice in the Cook Inlet is rare. During the winter, ice is thick and ships cannot enter the Cook Inlet safely. As a result, ENSTAR is preparing to bring in LNG cargos during ice-free periods to fill any gap left by Cook Inlet producers. Because the amount of gas offloaded during this time will be significantly higher than local demand, some of it will need to be moved directly to storage to cover gas supply gaps in Customer demand when LNG shipments are not available. This will require a storage service that has adequate volume and injection capacity to handle the LNG being offloaded at higher rates than can be immediately consumed by customers. The higher the injection rate, the quicker the LNG can be offloaded and the ship can leave port. This equates to lower LNG shipping and port costs, and, ultimately, lower costs for Customers. Regardless, without an additional adequate storage capacity, ENSTAR will not be able to manage deliveries of LNG supply.

57. In the early years, ENSTAR plans to purchase two to three LNG cargos each year. However, after fully transitioning to purchases from the LNG market, the amount of cargos will increase to between nine and eleven LNG cargos per year. Table 3 below shows the expected shipments and the months they would be brought in to meet Customers' demand once ENSTAR fully transitions to the LNG market. If the North

Slope pipeline is delayed or canceled and Cook Inlet production ceases, LNG will become the primary source of gas supply for the foreseeable future.

Table 3 – LNG Cargo Deliveries

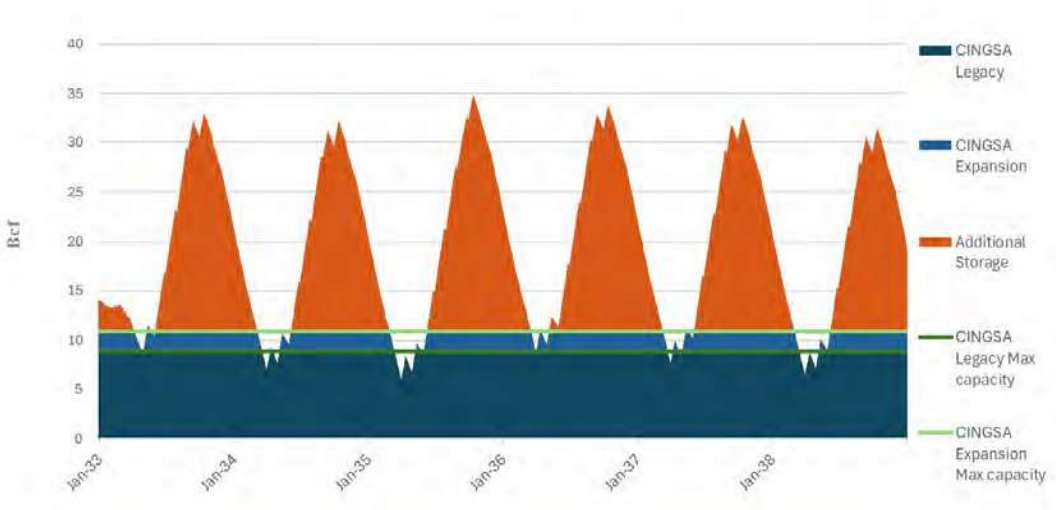
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Deliveries	Volume, Bcf
2033					1	2	2	2	2	1			10	34.28
2034				1	1	2	2	2	1	1			10	38.09
2035				1	1	2	2	2	1	1			10	41.90
2036				1	1	2	2	2	1	1			10	38.09
2037				1	2	2	2	1	1	1			10	38.09
2038				1	1	2	2	1	1	1			9	38.09

58. The case presented for LNG Deliveries estimates the number of LNG cargos required to meet ENSTAR's current Customers' demand and storage requirements developed to handle this new gas supply source. Any additional large demand from local power utilities or new large demand customers who are currently not Customers can be met by increasing the number of LNG cargos delivered each year. For example, if Matanuska Electric Association ("MEA") decides to fully transition to LNG purchases, ENSTAR will be able to add two additional cargos to its overall LNG purchase commitments, resulting in savings to all Customers. While adjusting the amount of LNG purchases and cargos is a simple and straightforward process, the need to develop additional storage capacity to handle new cargos will increase.

59. Additional storage, injection, and withdrawal capacity will be necessary due to delivery of LNG. As mentioned in my affidavit above, the need for storage volume and injection capability is critical when receiving LNG cargo deliveries so that we can offload large

volumes of LNG as quickly as possible to minimize costs for our customers. We also will need to develop additional withdrawal capacity to replace Cook Inlet production that is currently directly serving our winter load. Cook Inlet currently produces approximately 200 MMcfd. This deliverability will have to be replaced by storage withdrawal capacity during months when LNG deliveries are not available. As determined by the Gas Supply Model, Figures 9 and 10 below show the needed volume, injection, and withdrawal capacity to handle LNG cargos, while at the same time being able to reliably serve our Customers' needs in the winter season. Figure 9 shows the additional gas storage volume required, as we inject natural gas into the reservoir during the summer that will be withdrawn when demand increases in the winter months.

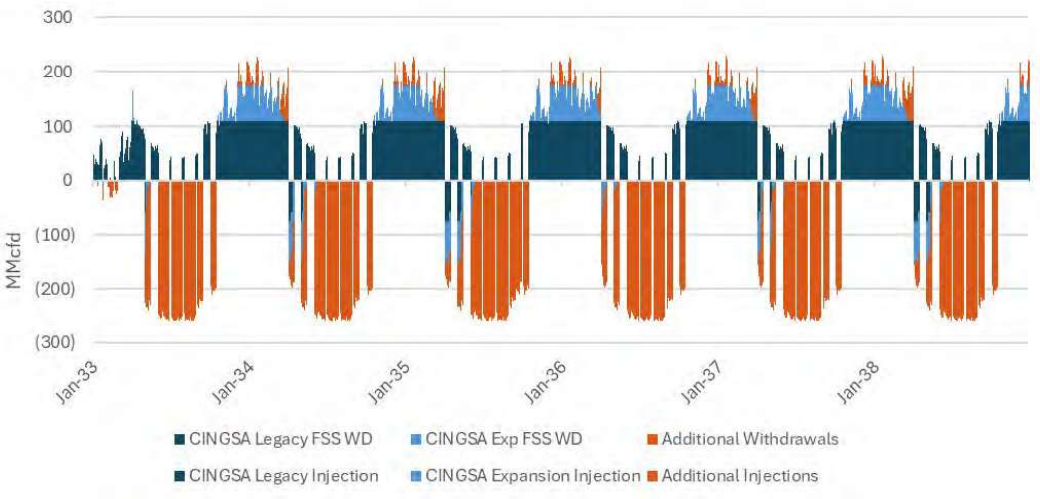
Figure 9 – Volume Required for LNG Deliveries



60. In Figure 10 below, the bars below zero reflect the needed injection required to offload the LNG cargos during low demand months. The bars above zero line represent gas that

will need to be withdrawn from storage to meet the daily demand for Customers during high demand months.

Figure 10 – Injections and Withdrawals Required for LNG Cargo Deliveries



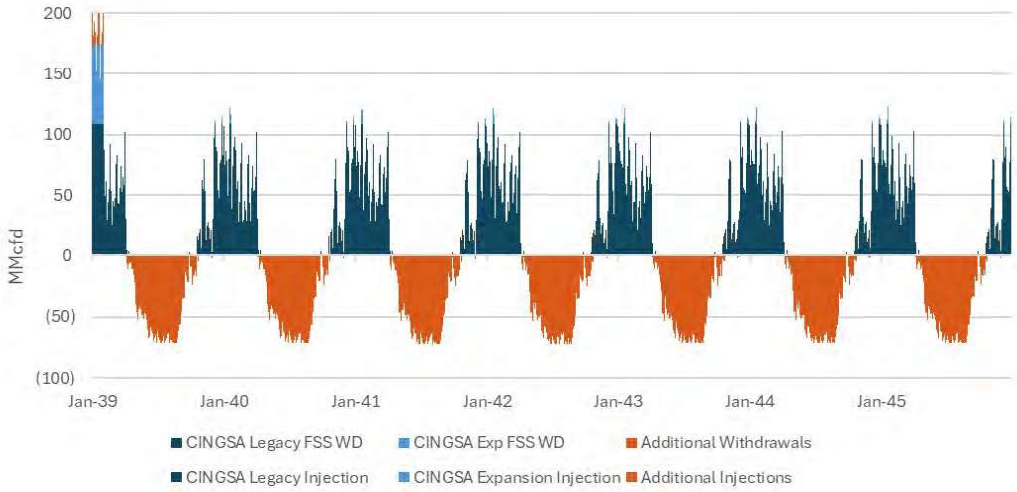
61. If a natural gas pipeline from the North Slope of Alaska is constructed, ENSTAR's proposed storage project will still be required. Even if a 42-inch diameter pipeline is constructed and can deliver gas to the ENSTAR system from the North Slope of Alaska and meet our Customers' demand in lieu of LNG Deliveries, the Company will still need additional natural gas storage due to the seasonal demand swings on the ENSTAR system. Contracting for capacity on a pipeline is less expensive if we buy consistent volumes on an annual basis. If the Company purchases gas on a more consistent basis, including in months when demand is lower (*e.g.*, summer months), then additional storage will be needed to accommodate those periods of reduced demand. Figure 11 below shows the

additional storage volume required in the scenario when our gas is supplied via pipeline from the North Slope.

Figure 11 – Storage Volume Required for NS Pipeline Deliveries

62. Figure 12 below shows the additional injection capacity required in the scenario when our gas is supplied via pipeline from the North Slope.

Figure 12 – Injections and Withdrawals Required for NS Pipeline Deliveries



63. As both Figures 11 and 12 demonstrate, storage is still critical for the scenario in which customers are being served with gas from the North Slope.

64. The conclusions of ENSTAR's storage needs assessment based on projected customer demand and changing gas supply sources were as follows:

- ENSTAR may need additional storage as early as December 2026 and will need additional storage in 2027;
- Expanded underground gas storage will play a critical role in ensuring deliverability of seasonal gas supply under all three gas supply options/timeframes considered by ENSTAR: Cook Inlet Deliveries, LNG Deliveries, and NS Pipeline Deliveries;
- ENSTAR will need to develop new gas storage solutions that will meet different requirements:

- ability to store large amounts of gas during the Cook Inlet Purchases and LNG Deliveries;
- ability to inject large amounts of gas in a short period of time during LNG Deliveries to offload LNG tanker;
- ability to withdraw large amounts of gas in a short period of time during LNG Deliveries to meet peak winter demand and replace the declining Cook Inlet production capacity; and
- ability to utilize the previously developed storage to manage flat deliveries of gas from North Slope and continue to meet Customers' seasonal and peak winter demand under various weather scenarios.

65. Based on the above analysis, ENSTAR will need to develop additional storage capacity of up to 15 Bcf to manage Cook Inlet and increase it up to 24 Bcf to manage LNG supply. The need for additional withdrawal capacity will start with deliveries of LNG supply. Additional deliverability of 100 MMcfd will need to be developed to reliably supply Customers under normal operations during the timeframe for LNG Deliveries. In order to meet Desing Day demand, ENSTAR will need to develop a total of 200 MMcfd of additional deliverability. During the same period, ENSTAR will need to develop up to 260 MMcfd of injection capacity to offload LNG shipments that could start as early as 2032. Once the North Slope pipeline starts delivering gas to Cook Inlet, ENSTAR will still be utilizing the additional storage service developed during the prior two timeframes. The analysis shows that purchasing flat gas from North Slope will require up to 9 Bcf of

additional storage, up to 55 MMcfd of withdrawal capacity and up to 75 MMcfd of injection capacity. Figures 13 and 14, along with supporting Tables 4 and 5 below, provide a summary of ENSTAR's projected future storage requirements under the three different supply options.

Figure 13 – ENSTAR's Storage Volume Requirements for 2026-2045

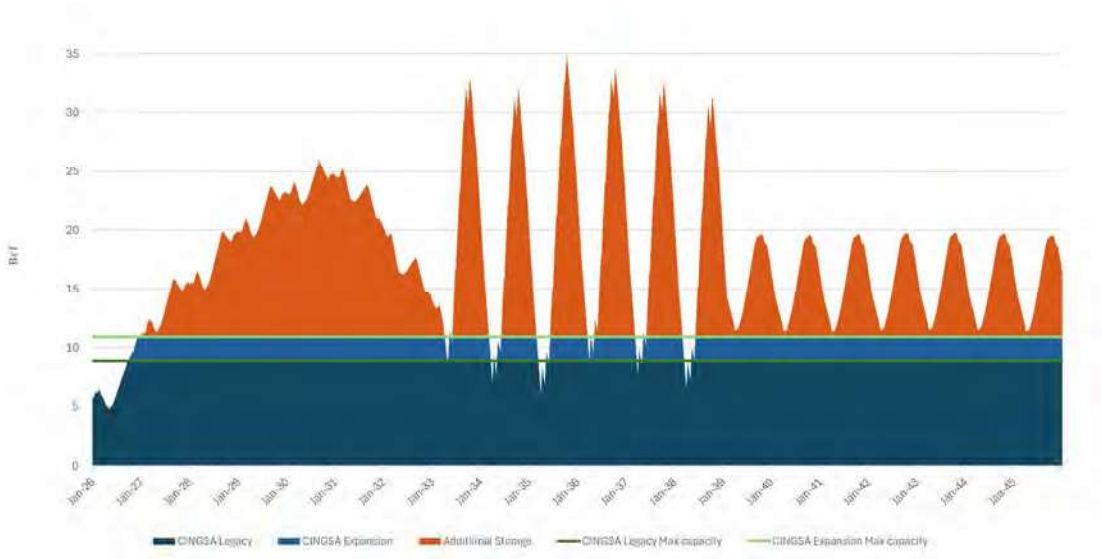


Table 4 – ENSTAR's Uncontracted Storage Volume Requirements for 2026-2045

Uncontracted	
Volume, Bcf	Max
Cook Inlet Deliveries	15
LNG Deliveries	24
NS Pipeline Deliveries	9

Figure 14 – ENSTAR's Daily Injections and Withdrawals Requirements for 2026-2045

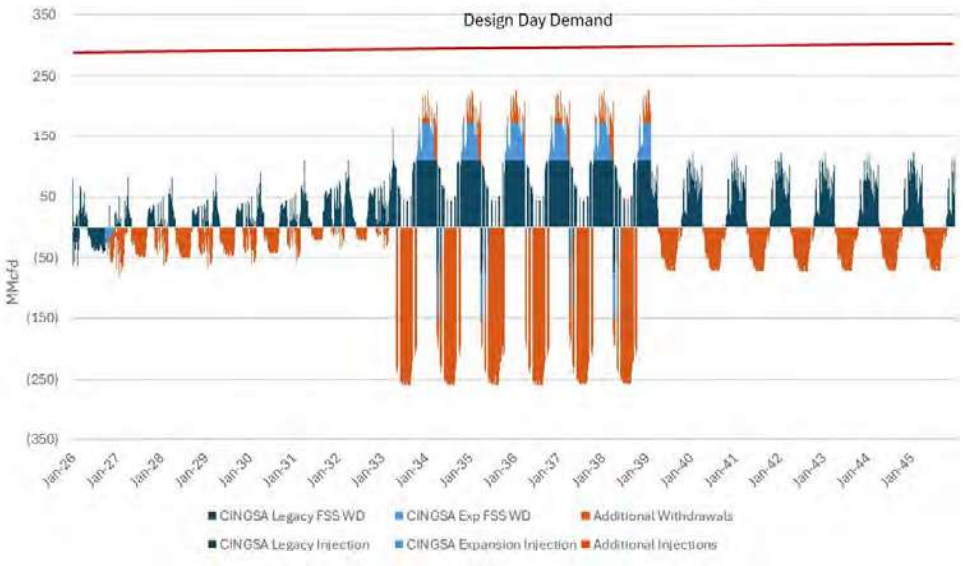


Table 5 – ENSTAR's Uncontracted Daily Injections and Withdrawals Requirements for 2026-2045

Uncontracted	
Withdrawal (MMcfd)	
Cook Inlet Deliveries	-
LNG Deliveries	100 (200 for Design Day)
NS Pipeline Deliveries	55
Injections (MMcfd)	
Cook Inlet Deliveries	80
LNG Deliveries	260
NS Pipeline Deliveries	75

Assessment of Gas Storage Options

66. With CINGSA already serving as a core asset, ENSTAR's objective is now to identify supplemental storage solutions that can address the specific operational windows and enhance overall system flexibility described above.

67. ENSTAR follows a structured and deliberate process to evaluate and select the optimal storage option to minimize costs to consumers and maintain service reliability. Long-term considerations, such as the changes and uncertainties in the way gas will be supplied to the region and the availability for additional development are considered. To this end, the general criteria used to evaluate multiple storage options are outlined below in Table 6.

Table 6 – Storage Evaluation Criteria

Priority	Evaluation Criteria	Description and Scoring Drivers
1	**Storage Requirements**	Must closely match identified storage injection and withdrawal needs (capacity and deliverability) identified in the analysis.
2	**Schedule Risk**	Must be available to meet additional storage requirements under multiple delivery profiles.
3	**Storage cost per Mcf/MMBtu**	Due to complexity of tariff structures, may be compared on a total annual basis given equal storage requirements.
4	**Scalability**	Capacity and deliverability requirements will step up over time - need to compare how each project is able to match this growth.
5	**Operational flexibility**	Notice requirements to turn storage from injection to withdrawal. Required commitment term. Efficient integration with CINGSA storage service.
6	**Stranded costs potential**	Requirement to invest in a project and potential for stranded capital when regional gas supply changes, such as shifting from LNG imports to pipeline gas.
7	**Project complexity and integration**	Ease of integrating a specific storage project into various potential future gas supply scenarios.

68. ENSTAR performed a comparative evaluation of potential storage solutions that could be easily integrated into ENSTAR's gas supply portfolio. The analysis focused on each option's operational capabilities, commercial structure, and alignment with regulatory expectations. Key criteria included deliverability, injection and withdrawal flexibility, cost transparency, and long-term reliability. By assessing these factors against the three

distinct gas supply delivery profiles described above, ENSTAR has identified a commercially available storage solution that enhances the Company's ability to meet Customers demand.

69. ENSTAR evaluated three alternative storage options: (1) storage service from Hilcorp Alaska Gas Storage LLC ("Hilcorp Storage"); (2) additional expansion of CINGSA; and (3) the development of new storage facility by ENSTAR.

70. Hilcorp Storage and Hilcorp operate three active gas storage facilities in Cook Inlet:

- Kenai Gas Pool 6 ("Pool 6"): Pool 6 was established in 2006, with Hilcorp utilizing approximately 27 Bcf of gas storage capacity to manage delivery obligations under its gas supply contracts. In August 2025, Hilcorp Storage received its certificate of public convenience and necessity ("CPCN") from the RCA to establish a new regulated storage utility to use Pool 6 for commercial operations. This storage utility is able to offer the market storage capacity for up to 38 Bcf with up to 130 MMcfd withdrawal and 107 MMcfd of injection rates.
- Pretty Creek: Pretty Creek was stablished in 2005, is operated by Hilcorp, and has a gas storage capacity of 1.9 Bcf and withdrawal/injections capacity of 8 MMcfd.
- Swanson River: Swanson River was established in 2001, is operated by Hilcorp, and has a gas storage capacity of approximately 3.5 Bcf and withdrawal/injections capacity of approximately 65 MMcfd.

71. Hilcorp currently uses its storage capacity secured in Hilcorp Storage as a main storage asset to balance seasonal loads swings against steady production rates. Swanson River and Pretty Creek, Hilcorp's "proprietary storage" facilities, are used to meet peak demands during short cold weather events. These storage facilities are integrated within Hilcorp's core upstream production business.

72. Per Hilcorp Storage's application in their CPCN proceeding, Docket U-25-007, Hilcorp Storage has storage capacity of 38 Bcf and maximum deliverability of 130 MMcfd. Hilcorp stated that the capacity "theoretically" could be increased with additional investment. Hilcorp Storage's tariff provides for storage services on a first-come, first-served basis to qualifying customers, subject to Hilcorp Storage's determination of operational availability and sufficient capacity to serve existing customers.

73. Based on publicly available data, as of January 12, 2026, two customers have signed up for Hilcorp Storage. Hilcorp Cook Inlet, LLC signed a five-year agreement with Hilcorp Storage for firm storage service for 27 Bcf of maximum storage capacity with injection capacity of 80.25 MMcfd and withdrawal capacity of 97.5 MMcfd. Chugach Electric Association ("Chugach") also entered into a five-year agreement with Hilcorp Storage for 5 Bcf of storage service. The agreement allows Chugach to gradually expand its reserved gas storage capacity over a three-year period, beginning with 1.5 Bcf in 2026, increasing to 3.5 Bcf in 2027, reaching the full contract capacity of 5 Bcf in 2028, and continuing through 2030. This 5 Bcf storage volume comes with 17 MMcfd of

withdrawal capacity. Additionally, Hilcorp Storage communicated in a recent filing that they are also working with MEA to provide them with storage service in a near future.

74. Table 7 below shows the breakdown of storage capacity in Hilcorp Storage based on the agreements and commitments made by Hilcorp Storage's customers.[1]

Table 7 – Hilcorp Storage Contract Commitments

	Hilcorp Storage	Hilcorp Cook Inlet LLC	Chugach	MEA	Remaining Balance
Volume, Bcf	38	27	5	TBD	6
Withdrawal, MMcfd	130	97.5	17	TBD	15.5
Injection, MMcfd	107	80.25	14	TBD	12.75

75. It is evident that the remaining uncontracted service in Hilcorp Storage is not sufficient to meet ENSTAR's impending storage requirements identified for any supply options and timeframes considered by ENSTAR. Additionally, based on my review of Hilcorp Storage tariff, it suggests that some of the terms of the services offered may present operational challenges even if the capacity was available.

76. CINGSA also does not have capacity available to satisfy ENSTAR's storage requirements. CINGSA's initial capacity was 11 Bcf of storage volume, 150 MMcfd of injection capacity, and 150 MMcfd of withdrawal capacity. All of CINGSA's initial capacity is fully subscribed. CINGSA recently expanded its service by adding an additional 2 Bcf of storage space and 75 MMcfd of injection and 65 MMcfd of withdrawal

[1] Hilcorp Storage TA 1-787 filed with the RCA on 1/5/2026 and Chugach's press release filed as a general correspondence with the RCA on 1/8/2026. Hilcorp Storage mentioned MEA as a potential customer in TA 1-787.

service, but that additional capacity is already fully contracted to ENSTAR. CINGSA is at full capacity and there is no potential for further expansion.

77. Given there is not sufficient storage capacity available in the market, ENSTAR has determined that the best short- and long-term option for its Customers is to develop its own storage facility. Having its own storage will reduce costs to Customers, provide operational efficiencies and effectiveness, and allow ENSTAR to meet its obligation to serve its customers.

New Storage Solution

78. The Company proposes to convert a depleted natural gas reservoir in the Kenai Peninsula Borough off Marathon Road within the City of Kenai currently owned by AIX Energy, LLC, to natural gas storage service. The Project will include existing facilities, including three natural gas injection/withdrawal wells, one well that will be repurposed into a disposal well, dehydration unit, natural gas compressor, 6-inch pipeline connecting the Project to the existing natural gas transmission system, and other smaller operational items. Mr. Matthew S. Federle describes the Project in greater detail in his affidavit.

79. The Project will benefit Customers in multiple ways. First, expanded underground gas storage that the Project provides will play a critical role in ensuring deliverability of seasonal gas supplies under the three gas supply options considered by ENSTAR. Second, it will enable ENSTAR to store large amounts of gas during Cook Inlet and LNG Deliveries. Third, during LNG Deliveries it will enable ENSTAR to inject large amounts of gas in a short period of time to offload LNG tanker and to withdraw large amounts of

gas in a short period of time to meet peak winter demand and replace the declining Cook Inlet production capacity. During the first few years of storage operations, access to additional storage volumes will provide ENSTAR with greater flexibility to procure Cook Inlet gas supply. Currently, ENSTAR must closely align its gas supply procurement with Customers' demand and available storage capacity. The Project will allow ENSTAR to purchase additional gas whenever it is available for a later use when local supply becomes more constrained. Lastly, there will be significant efficiencies gained in how ENSTAR plans to operate this storage facility. During times of high demand, ENSTAR will be able to quickly replenish its storage inventory balance in CINGSA on a regular basis in order to maintain the highest deliverability rates during the entire heating season.

80. ENSTAR intends to design and operate this facility in a manner that is similar to CINGSA's service.

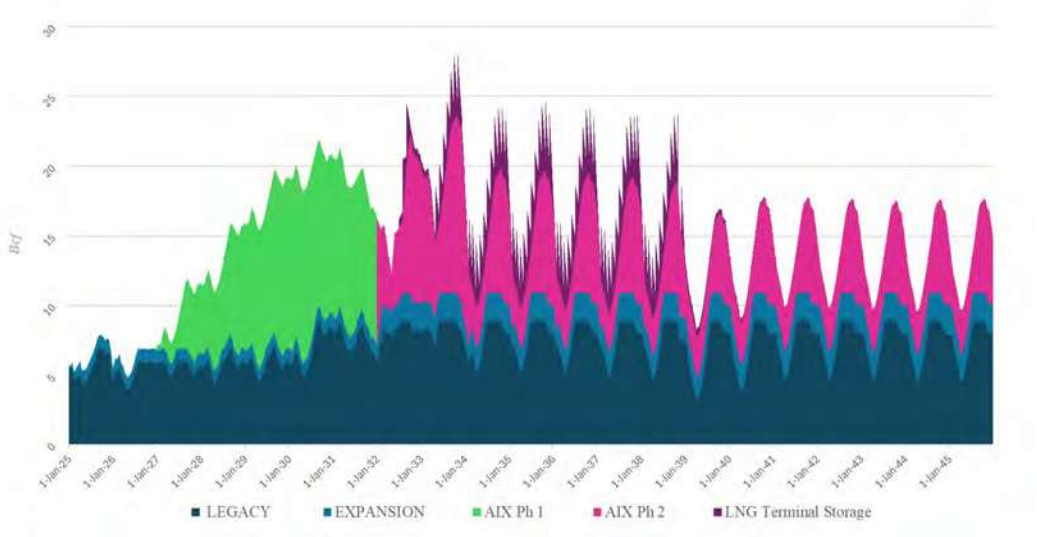
81. The Project as designed is anticipated to provide the following additional benefits to ENSTAR and its Customers:

- seasonal load balancing by injecting gas during low-demand months and withdrawing during high-demand months to meet heating needs;
- peak shaving by using additional withdrawal capacity to meet short-term spikes in demand;
- supply reliability and contingency planning by acting as a backup supply in case of pipeline disruptions, supplier failures and extreme weather events; and

- operational flexibility to manage pipeline nominations and balancing, optimize daily and hourly flows and respond quickly to demand fluctuations.

82. ENSTAR modeled this new storage option by simulating the daily projected storage use along with the storage service in CINGSA under various weather scenarios and gas supply options using an initial working gas volume of 17 Bcf and injection/withdrawal capacity of 50 MMcfd. Assuming the Cook Inlet market can no longer meet the annual volume and deliverability needs following the expiration of Amended APL-14 and ENSTAR transitions to LNG deliveries or North Slope pipeline deliveries, the Project can be expanded to provide up to 24 Bcf of total capacity and 180 MMcfd of deliverability. This expanded capacity is expected to cover the majority of ENSTAR's storage needs during these two different supply options. The results of this analysis are presented in Figure 15.

Figure 15 – Storage Assets Optimization with New Storage

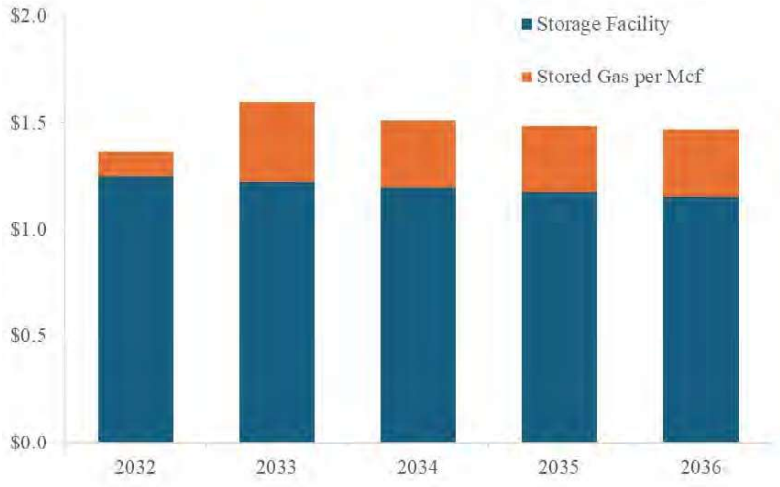


83. To estimate the cost impact to Customers, ENSTAR calculated its revenue requirement based on the capital costs associated with the Project as well as associated projected operating expenses, property taxes, state and federal income taxes, plant in service, accumulated deferred income taxes, and stored gas costs. Additionally, ENSTAR used its last authorized rate of return, from Order U-22-081(14), when calculating the revenue requirement. To show the full impact to Customers, ENSTAR included the cost of stored gas as well. While this cost is not tied to the actual construction and operation of the facility, it will have an impact to Customers as a result of ENSTAR storing gas in the new facility. The estimate of stored gas per Mcf is highly dependent on the actual weather experienced in ENSTAR's service territory, gas supply purchase price, and customer demand. Figure 16 shows the estimated cost to customers once the facility goes into service.

Figure 16 – Project's Estimated Cost Impact to Customers per Mcf

84. The initial costs of operating this facility while ENSTAR buys all of its gas from Cook Inlet producers is estimated to be below $1.00 per Mcf, or approximately $10-12 per month for an average residential customer. If ENSTAR transitions to LNG purchases, as assumed in Figure 15 above, the facility will need to increase the injection and withdrawal capacities to handle the high flow rates driven by the offloading of LNG cargos and declining Cook Inlet gas production as described in earlier sections of my affidavit. The estimated cost for this increased level of service is presented in Figure 17 under the years of 2032 through 2036.

Figure 17 - Project's Estimated Cost Impact to Customers per Mcf with LNG Impact



85. The costs for the additional storage are comparable to fees Customers pay for CINGSA's services. For the 2025-2026 Gas Cost Adjustment ("GCA"), ENSTAR estimated its fixed payment to CINGSA at $24,656,000 or $0.65 per Mcf if this payment is allocated over 37,651,000 Mcf of ENSTAR projected Customer demand. When CINGSA was placed in service in 2012, the facility's revenue requirement during the first full year of operation was $33,879,000 as stated in the stipulation entered into in U-10-051. Allocating this revenue requirement over ENSTAR's current demand produces $0.90 per Mcf, which is comparable to the cost expected during initial Project operations.

86. ENSTAR is not asking for recovery of any Project costs in this proceeding. At this time, ENSTAR is only asking for an advance determination that the Company's decision to develop the Project is prudent, in the public interest, and consistent with the Company's obligations under the Alaska Public Utilities Regulatory Act. When the amount of these charges and the precise mechanism by which they will be incorporated into ENSTAR's

rates are known, the Commission will have the opportunity to fully review them and to determine whether to approve them.

87. If the Commission approves ENSTAR's Petition, the Company proposes to file regular updates on the status of the Project. Among other things, these reports could include the total balance of incurred costs and a narrative statement detailing the progress of the Project with the Company's quarterly gas cost balancing account ("GCBA") filings.

FURTHER AFFIANT SAYETH NOT.

I. Johansen

Inna B. Johansen

SUBSCRIBED AND SWORN TO OR AFFIRMED before me, the undersigned notary, at Anchorage, Alaska, this 12th day of January, 2026, to which witness my hand and seal.

CHELSEA N. GUINTI
My Commission Expires
NOTARY PUBLIC
Nov 1, 2029
STATE OF ALASKA

Notary Public, State of Alaska
My commission expires: November 1, 2029

Inna B. Johansen

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2014 – Present.

Vice President of Regulatory and Gas Supply: 2024 – Present

Director, Gas Supply Operations: 2019 – 2024

Senior Manager, Gas Supply and Financial Planning: 2016 – 2019

Gas Supply Manager: 2015 – 2016

Manager of Budgeting and Finance: 2014 – 2015

Southern Company, Birmingham, Alabama: 2012 – 2014

Southern Power Company/Asset Manager: 2013 – 2014

Alabama Power Company/ Budget Analyst: 2012 – 2013

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2006 – 2012

Business Development Manager: 2010 – 2012

Operations Analyst: 2008 – 2010

Financial Analyst: 2006 – 2008

Alaska Pacific Bank, Juneau, Alaska: 2004 – 2006

Accounting Specialist

EDUCATION

Kazakh State Academy of Management, Almaty, Kazakhstan – BA in Finance and Accounting, 1999

Middle Tennessee State University, Murfreesboro, Tennessee: MBA – Emphasis in Finance and Accounting, 2003

OTHER

Commonwealth North, Member

Resource Development Council, Member

Western Energy Institute, Energy Management Team, Member

American Gas Association, Gas Control Committee

Habitat of Humanity, Board Member, 2011 – 2012

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	John M. Espindola, Chairman Steve DeVries Mark Johnston Robert M. Pickett John C. Springsteen
In the Matter of the Petition Filed by ENSTAR NATURAL GAS COMPANY, LLC for Advanced Determination of Decisional Prudence for Natural Gas Storage Project	Docket No. U-26-____

ENSTAR NATURAL GAS COMPANY'S PETITION FOR ADVANCED DETERMINATION OF DECISIONAL PRUDENCE FOR NATURAL GAS STORAGE PROJECT

AFFIDAVIT OF JOHN D. SIMS

AFFIDAVIT OF JOHN D. SIMS

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

John D. Sims, being first duly sworn, deposes and says:

Introduction

1. My name is John D. Sims. My business address is 5151 Fairbanks Street, Anchorage, Alaska, 99503. I am President of ENSTAR Natural Gas Company, LLC and Alaska Pipeline Company, LLC ("APC"), as well as President of Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"). ENSTAR Natural Gas Company, LLC and APC are regulated as a single entity and will collectively be referred to in my affidavit as "ENSTAR" or the "Company."

2. I have been employed by ENSTAR since 2005 and have held various management roles associated with the Customer Service, Credit, Human Resources, Business Development, and Public Affairs Departments. Immediately prior to my current position, I was the Vice President of Corporate Resources and Business Development for both ENSTAR and CINGSA. I hold a degree in Marketing Management from Hillsdale College and have a Master's Degree in Business Administration from the University of Alaska, Anchorage. My summary resume is attached hereto as Exhibit JDS-1.

3. As President of ENSTAR, I am responsible for the management, operations and financial performance of the utility. I am the leader of the dedicated employees who perform services for ENSTAR and interface with stakeholders external to the

Company, including the federal delegation, the Alaska State Legislature, the executive branch, and other business leaders in Alaska.

4. I have provided testimony before the ("RCA" or "Commission") on behalf of ENSTAR in Dockets U-08-025, U-16-066, U-18-004, U-19-014, U-22-081, and U-25-013/U-25-019, and on behalf of CINGSA in Dockets U-18-005, U-18-024, U-18-043, U-19-025, and U-21-058. I have also made several presentations before the Commission during my tenure with ENSTAR.

5. The purpose of my affidavit is to support ENSTAR's request for advance determination that the Company's decision to develop and integrate a natural gas storage facility into its utility system (the "Project") is prudent, in the public interest, and consistent with the Company's statutory obligations under the Alaska Public Utilities Regulatory Act. My affidavit provides a general overview of ENSTAR's filing and a high-level explanation of why the Project is needed to ensure that the Company can continue providing safe and reliable natural gas service to the 156,000 homes, businesses, and critical facilities throughout its service territory. In addition, I will provide a high-level description of the Project itself, including a description of the positive impacts the Project will have on the local economy and in Southcentral Alaska overall. I will also explain why an advance determination of prudence is necessary for ENSTAR to undertake the Project, and I will discuss the support the Project has received from various stakeholders. Finally, I explain and support the Company's request for an expedited decision on this filing.

6. I, or those under my direct supervisions, have reviewed all of the source material referenced in the citations in this affidavit. The references and quotes are true and correct representations or reproductions of those materials.

Overview of Petition

7. ENSTAR has a long history of delivering safe and reliable service to Alaska homes and businesses, and this Project represents a significant step in continuing that tradition. The Company proposes to convert a depleted natural gas reservoir in the Kenai Peninsula Borough into a natural gas storage facility to be integrated into the ENSTAR system. The Company is proposing to acquire the reservoir as well as associated facilities, including three natural gas injection/withdrawal wells, a disposal well, a dehydration unit, a natural gas compressor, a six-inch pipeline connecting the Project to the existing natural gas transmission system, and other smaller operational items. ENSTAR will optimize the reservoir's existing natural gas wells for storage service and install major equipment upgrades necessary to ensure that the facility can reliably store, inject, and withdraw natural gas while satisfying federal and state engineering and design and safety standards. ENSTAR witness Matthew S. Federle describes the various components of the Project in detail in his affidavit.

8. The Project is a necessary response to the significant—and well-documented—challenges that ENSTAR and other utilities currently face in procuring natural gas supply in Cook Inlet. In 2022, Hilcorp Alaska, LLC ("Hilcorp")— the largest natural gas producer in Cook Inlet—informed ENSTAR and other Alaska utility companies that Hilcorp would not be extending its existing contracts. ENSTAR's contract with Hilcorp is vital to the Company and its customers; it currently provides approximately

85% of the natural gas volumes ENSTAR's customers require each year, and a majority of the deliverability. Due to the expiration of ENSTAR's contract with Hilcorp in 2033, the Company must find alternative arrangements—and as this Commission knows, the Company has been actively exploring its options.

9. This Project will address two critical needs. First, it will help ensure that ENSTAR has adequate gas supply to meet its customers' needs into the future. With the new storage facility, the Company will be able to purchase gas supply as it becomes available and store those volumes to serve future customer consumption. Given the gas supply challenges in Cook Inlet, having the ability to call on needed gas volumes at any time—rather than scrambling to procure it "just in time"—will help ensure reliable, uninterrupted service to customers. ENSTAR has received commitments from producers to increase production so long as adequate storage is available. Additional storage encourages production because it mitigates the market risk of producing gas that cannot be sold due to bottlenecks from seasonal demand or storage capacity. As Southcentral Alaska utilities move closer to liquefied natural gas ("LNG") deliveries, one thing is clear, utilities cannot accept these deliveries without having access to more storage capacity. Second, the Project will ensure that ENSTAR has adequate deliverability and injectability to store and withdraw the gas from storage and deliver it through the Company's distribution system to customers. "Deliverability" refers to the rate at which gas flows through the pipeline system, and as I explain below, the more that customers demand in gas volume, the more deliverability the Company requires to maintain pipeline pressures. Once ENSTAR's APL-14 contract with Hilcorp expires, ENSTAR must not only replace the gas volumes, but also the

deliverability it receives under that contract. "Injectability" refers to the rate at which gas can be stored into the facility. In short, this Project will accomplish two critical goals: it will ensure that ENSTAR has adequate gas supply, and it will ensure that the Company can actually deliver that supply to customers, especially during times of peak demand.

10. There a sense of urgency related to the Project and a need for swift action. ENSTAR respectfully requests that the Commission consider this Petition on an expedited basis. As Company witness Ms. Inna B. Johansen explains, ENSTAR could potentially need storage as early as the fourth quarter of 2026, which is less than one year away. A natural gas production company in Alaska—BlueCrest Alaska Operating LLC ("BlueCrest")—has offered to supply ENSTAR with gas by the fourth quarter of 2026, but only if the Company has the ability to store those volumes (or use them immediately). It is my understanding that, if ENSTAR does not have the necessary storage capacity, BlueCrest could lose its financing and could need to search for new sources of capital, all of which would cause further delay in the production of gas. Additionally, as Ms. Johansen explains, the Company also will need new storage in 2027 so that it can receive new gas supplies from Furie Operating Alaska, LLC ("Furie"). Further, after ENSTAR executes its contract to acquire the depleted gas reservoir and associated facilities, the Company will need time to execute additional commercial agreements, including natural gas storage leases, rig procurement agreement, surface leases, and procurement of long-lead items and materials. For example, based on vendor input, ENSTAR will need six months to procure the pipe necessary to bring the Project in-service. That means that if the Commission were to

grant ENSTAR's request for an advance prudence determination by March 1, 2026, the Company will be able to receive the pipe by August, which will help ensure that the Project goes into service by the fourth quarter. As another example, and also based on communications with vendors, ENSTAR will need approximately nine to ten months to procure the compressor and compressor skid necessary to make the Project fully functional. Additionally, the advance prudence determination will facilitate necessary regulatory or agency approvals for the Project. Given all of these factors, expedited consideration of this Petition is wholly appropriate, because it will help ensure that the Project moves forward on the correct timeline. As stated above, the Company respectfully requests that the Commission issue an order granting the relief requested herein within 45 days of this filing.

11. As explained in further detail in the Affidavit of Mr. Federle, the current estimated cost of the Project is approximately $240 million, which includes all aspects of the initial Project and the installation of necessary equipment upgrades and other construction. Mr. Federle provides a breakdown of the costs in his affidavit. However, there will be additional costs required if more storage capacity with the associated deliverability is needed to meet future Customer demand.

12. In this Petition, ENSTAR requests only an advance determination of whether the Company's decision to develop the Project is prudent. The Company will seek to recover the costs through a future rate filing consistent with Commission procedures, orders, and applicable law. In any future rate proceeding, the Commission will retain its usual authority to evaluate the reasonableness and prudence of individual cost items.

Alaska Gas Supply Developments and Challenges

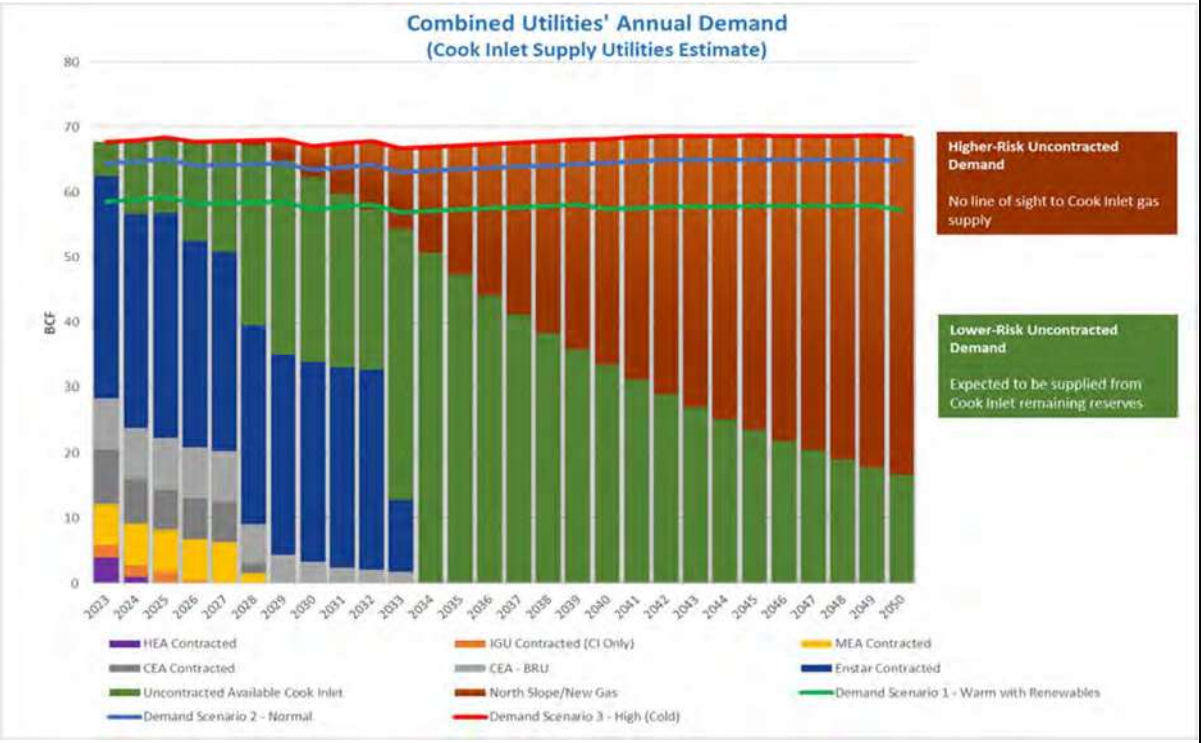
13. Southcentral Alaska utilities continue to confront significant challenges procuring natural gas to meet the forecasted demand. ENSTAR has been buying gas on an interruptible basis to serve a significant portion of its Customers' demand since 2025, and we expect this trend to continue. There are three active producers in the Cook Inlet: Hilcorp, Furie, and BlueCrest. Hilcorp has been outspoken about future Cook Inlet solutions. As stated in an article by Alex DeMarban in the Alaska Daily News on May 17, 2022, entitled, *Hilcorp warns Alaska utilities about uncertain Cook Inlet natural gas supplies*, Hilcorp has publicly stated that it cannot provide the same level of natural gas supply service after its existing contracts expire and that LNG imports will likely have to occur. Furie has publicly commented that it could not supply total market demand. BlueCrest is sitting on known pools of natural gas that require significant investments to bring its natural gas to market. They have the capability to develop and produce this gas as early as the fourth quarter of 2026. However, if developed, they anticipate natural gas production from their wells would be more than what the existing market could consume on a daily basis in the near term. If ENSTAR had adequate storage in place, it would allow BlueCrest to immediately develop these critical reserves for the benefit of Southcentral Alaska utilities. I have included the executed contract with BlueCrest as Exhibit JDS-2 to this affidavit. The contract volumes are conditioned upon the availability of storage.

14. While the developments with BlueCrest are extremely encouraging, the overall gas supply circumstances have left the Southcentral utilities with no other choice but to look for other markets and solutions beyond what currently exists. This Petition

addresses one of the key pieces to the puzzle that will be required for ENSTAR to bring additional Cook Inlet supplies online in the near term, but also allow us to meet customer demand beyond 2032 via LNG deliveries or natural gas from the North Slope. ENSTAR is requesting a predetermination of prudency to develop the Project capable of providing adequate storage, injection, and withdrawal capacity to meet customer demands today and in the future.

15. In May 2022, Hilcorp met collectively with all of the stakeholders of Cook Inlet gas and communicated to the group that Hilcorp would not be extending existing contract terms into the future. While the stakeholders were equally surprised, Hilcorp's announcement carried distinct impacts for each utility. For Homer Electric Association ("HEA"), the announcement meant that HEA would have no natural gas under contract starting in less than two years. For Matanuska Electric Association ("MEA") and Chugach Electric Association ("Chugach"), it meant that they would have to find gas to generate power for customers effective April 1, 2028. Golden Valley Electric Association ("GVEA"), a utility that purchases cheaper power from Southcentral Alaska utilities when available, had to refocus its efforts on improving its existing power generation sources and move away from its plans of reducing power generated from the coal-fired Healy generating station. Figure 1 below was created by Berkeley Research Group ("BRG") and is the result of a collaborative effort with all Railbelt Utilities (HEA, MEA, Chugach, Interior Gas Utility, GVEA, and ENSTAR) along with the Alaska Department of Natural Resources ("DNR") to show projected utility demand, the existing gas supply contracts that are in place, and how that demand can (or cannot) be met in the future.

Figure 1 – Utility Demand and Supply[1]



16. For ENSTAR, the news that Hilcorp would not be extending existing contracts represented a much more challenging situation because of the type of service that ENSTAR Gas Sales Customers ("Customers") require. On an annual basis, Customers consume approximately 38 billion cubic feet ("Bcf") of gas. On a daily basis, they require between 30 and 320 million cubic feet per day ("MMcfd"), depending on the day and time of year. ENSTAR's contract with Hilcorp provides a majority of both daily and annual requirements through March 31, 2033. Specifically, Hilcorp provides for 85% of the natural gas volumes on an annual basis, along with 162 MMcfd of deliverability, which represents the largest portion of ENSTAR system deliverability

[1] BRG, Alaska Utilities Working Group Phase I Assessment: Cook Inlet Gas Supply Project, June 28, 2023; BRG and ENSTAR presented their findings at the RCA public meeting on June 28, 2023.

needs in the winter months. The contract also gives ENSTAR other options for purchasing additional deliverability, such as Daily Call Option and Needle Peak Call Option provisions. The Company needs to replace both the annual volumes and daily deliverability from this contract. ENSTAR witness Ms. Johansen discusses the gas supply situation in more detail in her affidavit.

17. ENSTAR's priority is to maximize Alaska's resources. In that effort, we continue to have discussions with local producers that hold natural gas production leases in Cook Inlet to buy annual volumes. These producers have been reluctant to enter into firm contracts to date. In parallel, we are also working with Glenfarne Alaska LNG, LLC ("Glenfarne") to bring LNG imports to Southcentral Alaska and natural gas from the North Slope. This work has been publicly discussed on several occasions and there have been numerous filings with the Commission in support of that effort.

18. Throughout these discussions with local producers in Cook Inlet and Glenfarne, one important fact has become clear: none of them can meet the daily deliverability needs of our Customers. They can help only with the annual demand requirements. This is why additional storage is so critical, no one else can provide what ENSTAR Customers need.

19. Additional gas supply does not result in additional deliverability. Deliverability refers to the rate at which gas flows through the pipeline system. The more gas customers pull from the system to meet their needs (demand), the higher deliverability we need to maintain sufficient pipeline pressures. The gas the remaining producers can flow from the Cook Inlet cannot be delivered at a sufficiently high rate to replace the deliverability ENSTAR receives under the Hilcorp contract. Moreover, LNG cargoes will be

delivered only periodically throughout the year – and not likely during the winter months due to ice conditions in the Cook Inlet. So, while LNG brings sufficient volume, it cannot be constantly flowed through the system at variable rates as customer demand fluctuates with the weather.

20. As discussed in more detail by Ms. Johansen, there are currently no viable options available that are capable of providing the storage services required to meet our Customers' daily demands. For example, based on publicly available information, Hilcorp's third party storage facility is 84% subscribed with additional storage contracts in discussions with another utility. This means that the facility has less than 6 Bcf of un-contracted storage capacity. For this reason, ENSTAR is proposing this Project to store large quantities of additional Cook Inlet production, regasified LNG, or gas from the North Slope and flow it at the rate that Customers need and the system requires to maintain reliable and uninterrupted gas service.

21. ENSTAR, the Commission, and other stakeholders—including other utilities in Southcentral Alaska—have been discussing the need for additional storage for several years. For example, in 2022, I offered the following comments during a public meeting before the Commission:

> [T]he heads of the various utility groups for the Railbelt have been meeting very frequently [] as we discuss our long-term gas supply needs and the challenges that we face here in the future[,] and one of the things that we've all come to agreement upon is that energy storage is going to be critical for meeting our customers['] needs here in the future and CINGSA obviously plays a big part of that. So we're evaluating currently how we see ourselves in that mix in the future and whether or not there are things that we can offer to customers going forward in an expanded role or perhaps looking at other areas of the state where we could participate in storage. So there's a lot of work on that end and I just wanted to … make sure the Commission was aware that we're

> looking at those things, and more importantly, looking at those things as a group, so we've had a lot of really good positive meetings to date and hopefully, we can present to the Commission here in the near future on some of the things that we've been discussing.[2]

Additionally, in another public meeting in 2023, I explained that the CINGSA storage facility is not capable of meeting all of Southcentral Alaska's storage needs, and that additional facilities would be needed:

> As far as CINGSA and how it plays into all of that … it's obviously a key component, but there's still significant storage [needs]. Additional storage is going to be required. … [W]e definitely are evaluating different storage options and how we can take advantage and leverage those better.[3]

To take just one more example, during a public meeting in October 2024, I noted as follows:

> …[I]t's unanimous across the board for Southcentral utilities. Everyone needs additional storage. Whether you're an entity that's looking to leverage additional renewable resources that are out there or a natural gas utility. Storage is a critical piece of infrastructure, not just CINGSA, but additional. It is really one of the key components to what I believe is the success of not just Cook Inlet producers, but the utilities and meeting their goals and their mission statements. And as it gets harder and harder to meet our deliverability, that's where storage comes in.[4]

These are just some examples of the prior discussions that have occurred before this Commission describing the need for additional storage. Like ENSTAR, other stakeholders also have commented on why additional storage is necessary.

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[2] Regulatory Commission of Alaska, Public Meeting Transcript at 3-4 (Oct. 26, 2022).

[3] Regulatory Commission of Alaska, May 10, 2023 Public Meeting, Transcript at 12.

[4] Regulatory Commission of Alaska, October 23, 2024 Public Meeting, Transcript at 14.

Project Description

22. As described earlier in my affidavit, ENSTAR needs to replace the annual natural gas volumes and daily deliverability due to the expiration of the Hilcorp contract. In the later part of 2024, ENSTAR was approached with an opportunity to acquire existing infrastructure with the potential to develop it as another storage facility. After months of due diligence, it was determined that this Project will fill the daily supply gap by providing ENSTAR with the required storage capacity, withdrawal, and injection services needed to attract additional production/supply and serve customer demand. ENSTAR will accomplish this by utilizing a depleted reservoir in the Cook Inlet appropriately sized for ENSTAR's requirements and modifying it as needed to meet the standard codes and regulations for natural gas storage service. The Project will take advantage of existing infrastructure to complete the initial phase, including four existing wells, dehydration equipment, a compressor, and an existing pipeline that connects the storage facility to the integrated natural gas pipeline system that can be leveraged for storage service to the benefit of Customers.

23. The single-most impactful component of cost for the withdrawal portion of storage service is in the size of the depleted reservoir. To achieve high withdrawal deliverability rates, you need to achieve a high rate of pressure in the reservoir. A high rate of pressure in a depleted reservoir can be achieved utilizing two different approaches, or a combination thereof: (1) the injection of base gas into the reservoir; or (2) the installation of compression. The larger the depleted reservoir, the more base gas and/or compression that will be required to achieve the desired withdrawal rate. Think of a deflated balloon; in order to get a faster rush of air out of the balloon, you

need to fill it with more air. The larger the balloon, the more air you need, and the faster air can flow back out. Returning to the natural gas storage reservoir, base gas and compression are necessary elements, and both are significant contributors to overall Project cost. Throughout the initial planning and development of the Project, ENSTAR has looked to reduce these costs as much as possible.

24. ENSTAR conducted a review of available reservoirs that could be utilized for storage. In 2009, ENSTAR hired TransCanada Pipelines LTD. to study the Cook Inlet Basin and locate natural gas reservoirs that displayed the characteristics needed for storage operations, including requisite deliverability characteristics. Based on the review of publicly available data, the initial screening resulted in only eleven prospective pools for use as gas storage reservoirs of the 48 pools the firm evaluated. The eleven pools identified as prospects were selected based on a variety of attributes, such as proximity to the pipeline system and eliminated those with limited access to infrastructure (roads, rail, airstrips), which would lead to high construction and operating costs. Those eleven prospects were then further scrutinized, resulting in elimination of four prospects. From the remaining group of seven prospects, CINGSA eventually selected the reservoir that would ultimately become the 13 Bcf storage facility in service today.

25. In 2025, ENSTAR hired ASRC Consulting and Environmental Services, LLC ("ACES") to update the information gathered in the original 2009 review. In his affidavit, Mr. Federle discusses ACES' updated review and explains why the result of this work revealed that there is only one available prospect for ENSTAR to use for its storage needs.

26. The size of the reservoir one of the determining factors in ENSTAR's decision. This is very much a "Goldilocks and the Three Bears" scenario: a reservoir that is too small cannot provide the full suite of services (storage capacity, withdrawal, and injection) that is needed for our Customers' demand; but a reservoir that is too big will require ratepayers to be burdened by unnecessary costs in the form of additional base gas or compression (or both). The reservoir ENSTAR proposes to include for the Project is appropriately sized and will provide the best service to fill the void left by the expiration of the Hilcorp contract, at a reasonable cost.

27. The site for the Project is optimal in many ways. First and foremost, the total capacity of the reservoir allows for minimal amounts of base gas to be injected to provide necessary deliverability rates for future needs. Additionally, its close proximity to CINGSA in the City of Kenai will reduce operating costs and allow for efficiencies to be gained between the two facilities. Mr. Federle will also discuss the characteristics of the prospect in his affidavit.

28. As discussed above, ENSTAR is estimating that the Project will cost approximately $240 million. This will allow ENSTAR to initially store up to 17 Bcf of working gas and bring on an additional 50 MMcfd of deliverability, both of which can be increased with additional development on an as-needed basis to accommodate changes in the Cook Inlet, LNG deliveries, or North Slope gas.

29. Starting in 2027, the Project will increase Customer bills by less than $1 per Mcf or approximately $10-12 per month for an average residential customer. Ms. Johansen discusses the cost per customer in further detail in her affidavit.

30. There are several direct and indirect economic benefits that come from a significant project like this. First, ENSTAR plans to complete a significant amount of the work required by utilizing local businesses and contractors in Alaska. ENSTAR prioritizes the hiring of Alaskans and will do the same with the Project. For comparison, CINGSA utilized over 100 different Alaska companies and contractors to complete construction on the CINGSA expansion project. In turn, these companies and contractors hired Alaskans to perform over 126,000 labor hours to help complete the project. ENSTAR expects those numbers to be similar or greater for this Project, which will infuse an estimated $50 million in the local economy, particularly benefitting the Kenai Peninsula Borough.

31. As this Commission is aware, ENSTAR operates CINGSA based on the terms of an Operation and Maintenance Agreement, so the Company is intimately aware of what is required to operate storage services. On an annual basis, CINGSA uses approximately 16 local contractors for a variety of needs to maintain safe and reliable natural gas storage service. Not only would those same services be required for ENSTAR's storage facility, but there are likely to be efficiencies gained and the benefit of economies of scale by operating two similar facilities under the same operating group. This would result in ENSTAR's operations and maintenance costs being lower than they otherwise would be if ENSTAR was procuring services on its own.

Request for Advanced Determination of Prudence

32. Natural gas storage is a relatively new service for utilities. In 2010, the Alaska Legislature recognized the need for natural gas storage in the Cook Inlet Basin and enacted the Cook Inlet Recovery Act ("CIRA"), which amended the Alaska statutory

definition of a public utility in AS 42.05.990 (6)(G) to include "furnishing the service of natural gas storage to the public for compensation." The Sponsor Statement for CIRA included the following statement, in part:

> Residents of Southcentral Alaska are at risk that in the near future there will not be enough natural gas produced in Cook Inlet to heat and light their homes and businesses. Legislative action now can help address this challenge before it becomes a crisis. A critical and universally recognized part of the solution is large-scale gas storage, allowing utilities to purchase gas during lower demand periods; hold the gas in storage; then withdraw it when needed. Establishing gas storage is crucial, and the state needs to promote the rapid development of storage facilities.[5]

33. The Alaska State Legislature passed CIRA unanimously, making it clear that the Commission had the authority to regulate gas storage facilities as public utilities under AS 42.05, the Alaska Public Utilities Regulatory Act.

34. Since that time, ENSTAR, CINGSA, and the Commission have worked collaboratively to ensure infrastructure is in place to meet the challenging daily demand requirements of natural gas customers in the region. As supply options for volumes and daily demand requirements evolve, ENSTAR wishes to continue this collaboration and provide the Commission another opportunity to "weigh in."

35. ENSTAR believes we have found the appropriate solution, and a pre-determination of prudency for this solution will show the Commission's confidence in our plan moving forward and allow us to access and spend the necessary capital to implement the plan. Without a predetermination of prudence from the Commission for this project ENSTAR will not be able to access the necessary financing to develop the project as it

[5] Rep. Hawker Sponsor Statement of House Bill 280, introduced on February 5, 2010.

will be a condition precedent related to any transaction to close on the existing facilities, and for any significant capital spend to occur.

36. ENSTAR does not need to amend its Certificate of Public Need and Necessity ("CPCN") to build a storage facility for the benefit of its Customers. ENSTAR plans to utilize this storage facility to manage its gas supplies to serve its Customers. ENSTAR is not proposing to sell a new service (e.g. firm storage service), the Project will be located within the Company's existing service territory, and the Project will be integrated with the Company's system.

37. The Alaska Statutes provide guidance for the Commission's evaluation of the necessity of a new CPCN or modification of an existing one for the purposes of natural gas storage service. AS.42.05.990 is very specific when referring to the service of natural gas storage. AS.42.05.990(11) states that the "service of natural gas storage" means the operation of a natural gas storage facility primarily or exclusively for the benefit of third-party customers, and not for the benefit of the owner, operator, or manager of the natural gas storage facility; "service of natural gas storage" does not include the storage of natural gas by a utility to meet its Customers' demand. ENSTAR will not be offering storage as an independent service to any of its customers should the Project move forward.

38. The Commission has the authority to grant ENSTAR's request. Based on the authority granted to it in Alaska Statute 42.05.141(a)(3), which states that the Commission's role is to "make or require just, fair and reasonable . . . facilities for a public utility." ENSTAR's Project will be a critical component in providing safe and reliable natural

gas service to its Customers. The Commission has the authority to approve ENSTAR's request, and ENSTAR is requesting that it expeditiously do so.

39. The Commission previously described the standard it will use to review a utility's request for an advance determination of prudence. Although I am not a lawyer, my understanding is that when CINGSA requested an advance prudence determination of a proposed project in 2018, the Commission described its standard of review as follows:

> We find that under any prudency standard, the reviewed capital investment decision must first be found to be justified by the utility's service obligations. Specifically, the investment (whether reviewed before or after completion) must be required for the utility to provide the services authorized by its certificate of public convenience and necessity (certificate) and provide them in a manner that complies with the statutory requirements of AS 42.05.291. Under these provisions each utility must furnish and maintain "adequate, efficient, and safe service and facilities" and the utility's provided service "shall be reasonably continuous and without unreasonable interruption or delay."
>
> Once this necessary relationship has been established, inquiry turns to whether the chosen investment represents a "prudent" way of providing those required services. In the case of a post-construction prudency determination, we (like other regulators) have concluded that protecting the utility's actual expenditure of its funds in order to provide required services justifies the imposition of procedural limitations on challenges to decisional prudency. Initially, protection is extended through a presumption of prudency. Absent a challenger's presentation of sufficient evidence of "imprudence," the utility is not required to establish the prudency of its decisions. Thereafter, the utility is advantaged by our use of a lesser standard of prudency met by proving its decision was "a reasonable one." The utility is not required to prove its full consideration of all options before ultimately choosing a "good" option, one of the "better" options, or even the "best" option.
>
> Because there is not an actual utility expenditure to protect in the case of a pre-construction determination, we agree with the AG and the other parties that CINGSA does not enjoy a presumption of prudency in this instance. Therefore, we conclude that in order to prevail, CINGSA must produce a preponderance of evidence on both requirements described above. Initially, we must find that CINGSA has produced a preponderance of evidence establishing that its Project is prudent

> because it is "necessary" in order to provide an authorized service (in this case daily withdrawal service) that is "adequate" in amount and made available in a manner that is "reasonably continuous and without unreasonable interruption." If we find that CINGSA has carried its burden in this regard, then we must proceed to determine whether the Project is a "prudent" option for obtaining that result, using a yet to be articulated standard that either mirrors the "reasonable decision" one adopted in previous post-construction determinations or is a more stringent standard for specific application to pre-construction determinations such as "best decision" among feasible options.[6]

40. The investment in this Project is required for ENSTAR to provide its certificated service to customers for all of the reasons explained by me in this affidavit and in the Affidavits of Ms. Inna B. Johansen and Mr. Federle in support of this Petition.

41. The Project represents a reasonable decision and represents the best decision among the feasible options.

42. ENSTAR's Petition amply demonstrates that an advance determination of prudence is appropriate in this proceeding. First, ENSTAR's filing demonstrates that the proposed Project "is required for the utility to provide the services authorized by its certificate of public convenience and necessity . . . and provide them in a manner that complies with the statutory requirements of AS 42.05.291." Second, the Company's filing also demonstrates that the proposed Project is not only prudent, but also the best available option for ensuring that the Company can continue to fulfill its obligations to Customers in the future.

43. In addition to my affidavit, the following Company employees provide affidavits in support of ENSTAR's Petition:

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[6] Order U-18-024(17), *Order Denying Petition, in Part, and Closing Docket*, dated February 28, 2019, at 15-17.

- ***Inna B. Johansen***, Vice President of Regulatory and Gas Supply, ENSTAR and CINGSA. Ms. Johansen discusses ENSTAR's obligation to provide safe and reliable service to its Customers and how the Company meets its gas supply needs today. She also describes Customers' natural gas demand, ENSTAR's current gas supply resources, and its assessments of options supporting the decision to develop the Project. Finally, Ms. Johansen discusses cost recovery associated with the Project and ENSTAR's plans for reporting on the status of the Project's development to the Commission.
- ***Matthew S. Federle,*** Director of Gas Plant Storage, ENSTAR. Mr. Federle discusses the planning, design, and engineering for the proposed Project. He also describes ENSTAR's cost estimates, management, and development schedule for the Project.

Public Support for Natural Gas Storage

44. ENSTAR has received support for this Project.

45. ENSTAR is very humbled and honored to have the support of the Department of Natural Resources and BlueCrest, which have expressed written support for the Project. Attached to my affidavit, collectively, as Exhibit JDS-3 are letters of support. As demonstrated by this correspondence, the market is excited about the opportunity presented by the Project.

46. In 2023, the National Association of Regulatory Utility Commissioners ("NARUC") Executive Committee approved the creation of the Gas-Electric Alignment for

Reliability ("GEAR") Task Force charged with developing recommendations and solutions for reliability concerns that exist for natural gas and electric utilities, especially during winter storms. Attached to my affidavit as Exhibit JDS-4 is a recommendation issued in March 2025 from the GEAR Task Force that discusses gas storage opportunities. Among other things, this recommendation states the following:

> While there are significant costs and operational limitations to the deployment of new storage facilities, it remains the best method to mitigate situations where there are spikes in demand and/or disruptions to fuel gas supply. Therefore, it is critical for all stakeholders to evaluate and implement sufficient storage options of all types.[7]

47. Additionally, the GEAR Task Force recently published a report addressing serious reliability concerns for the electric and natural gas industries.[8] The report includes nine recommendations, including one related to "Gas Storage Opportunities" that recommends that states evaluate how to encourage investment in the development of additional natural gas storage and associated infrastructure.[9] NARUC's Board of Directors adopted the GEAR Report and its recommendations in November 2025.[10]

48. On multiple occasions, the Federal Energy Regulatory Commission ("FERC"), North American Reliability Corporation ("NERC"), and NERC's regional entities have published joint reports recognizing the need for additional storage in the United States. In recent years, they have published reports on Winter Storm Uri, which occurred in

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[7] JDS-4, page 1.

[8] National Association of Regulatory Utility Commissioners Task Force on Gas-Electric Alignment for Reliability (GEAR), Report & Recommendations (Nov. 2025) ("Gear Report").

[9] *Id.* at 8.

[10] NARUC, EC-1 Resolution on Gas-Electric Alignment for Reliability (GEAR) Recommendations (adopted Nov. 11, 2025).

February 2021,[11] Winter Storm Elliot in December 2022,[12] and the arctic events of January 2025, including Winter Storms Blair, Cora, Demi, and Enzo.[13] These reports addressed the critical need for additional natural gas storage facilities, given the numerous benefits they provide to the natural gas system. For example, the 2025 Joint Report analyzed the benefits that natural gas storage provided during the January 2025 Arctic events and discussed in detail the crucial role storage can play in meeting demand and supporting reliability.[14] These joint reports have also acknowledged that increased storage volumes could assist in stabilizing the natural gas market during supply shortfalls.[15]

49. The FERC, NERC, and NERC's regional entities make positive recommendations relating to the need for additional natural gas storage. In light of the critical need for and the benefits provided by natural gas storage facilities, on several occasions, FERC, NERC, and NERC's regional entities have encouraged FERC and state regulators to consider increasing the use of natural gas storage.[16] Moreover, they recommend that federal and state entities with jurisdiction over natural gas infrastructure enact measures to address natural gas supply shortfalls, including measures to encourage investments

[11] FERC – NERC – Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021) ("2021 Joint Report").

[12] Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliot, FERC, NERC and Regional Entity Staff Report (Oct. 2023) ("2023 Joint Report").

[13] January 2025 Artic Events A System Performance Review, FERC, NERC, and its Regional Entities Joint Staff Report (Apr. 17, 2025) ("2025 Joint Report").

[14] 2025 Joint Report at 18.

[15] 2021 Joint Report at 235.

[16] 2021 Joint Report at 197.

in natural gas storage facilities and to provide financial incentives for the natural gas system.[17]

Conclusion

50. As I discuss in this affidavit, ENSTAR has a long history of delivering safe and reliable service to Alaska homes and businesses, and this Project represents a significant step in continuing that tradition. The natural gas supply challenges that ENSTAR and other Alaska utilities face are significant, and the need to resolve them is urgent. This Project is not only reasonable and prudent, but also the best available option for helping the Company overcome those challenges. By granting an advance determination of prudence in this proceeding, the Commission will help ensure that ENSTAR can continue to fulfill its obligation to provide safe, reliable service to the thousands of homes and business throughout its service territory. Accordingly, ENSTAR respectfully requests that the Commission review this Petition and issue an order with the findings requested herein within 45 days of this filing to ensure that the Company can move forward with this critical Project on the appropriate timeline.

FURTHER AFFIANT SAYETH NOT.

[17] 2021 Joint Report at 234-35.

John D. Sims

SUBSCRIBED AND SWORN TO OR AFFIRMED before me, the undersigned notary, at Anchorage, Alaska, this 12th day of January, 2026, to which witness my hand and seal.

Notary Public, State of Alaska
My commission expires: November 1, 2029

CHELSEA N. GUINTU
My Commission Expires
NOTARY PUBLIC
Nov 1, 2029
STATE OF ALASKA

John D. Sims

EMPLOYMENT

TriSummit Utilities, Inc. 2023 - Present

ENSTAR Natural Gas Company/Alaska Pipeline Company

President, 2023 - Present

SEMCO Energy, Inc. 2005 - 2023

ENSTAR Natural Gas Company/Alaska Pipeline Company

President, 2017 - 2022

Vice President, Corporate Resources and Business Development: 2015 - 2017

Director, Business Development 2013 - 2015

Director, Corporate Communications & Customer Service 2011 - 2013

Manager, Corporate Communications & Customer Service 2009 - 2011

Manager, Credit & Customer Service 2007 - 2009

Business Development & Public Affairs Representative 2005 - 2007

American Family Life Assurance Company

District Manager 2002 - 2005

Sales Representative 2002

EDUCATION

Hillsdale College: Bachelor of Arts, Marketing Management

University of Alaska Anchorage: Masters, Business Administration

OTHER

Board Member, Junior Achievement Alaska

Board Member, Chugiak Eagle River Foundation

GAS SALE AND PURCHASE AGREEMENT

BETWEEN

BLUECREST ALASKA OPERATING LLC

AND

ALASKA PIPELINE COMPANY

December 20, 2025

GAS SALE AND PURCHASE AGREEMENT

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GAS SALE AND PURCHASE AGREEMENT

This GAS SALE AND PURCHASE AGREEMENT ("Agreement") effective as of September 1, 2026 ("Effective Date"), is entered into by and between BlueCrest Alaska Operating LLC. ("Seller"), and Alaska Pipeline Company, LLC ("Buyer"). Seller and Buyer may be referred to collectively, as "Parties" and each, individually, as a "Party".

RECITALS

A. Seller owns, controls, or has the right to dispose of certain volumes of Natural Gas produced from lands located in the Cook Inlet region of Alaska (the "Project");

B. Buyer is a public utility that holds Certificate No. 141 from the Regulatory Commission of Alaska ("RCA"). Buyer, and its public utility affiliate ENSTAR Natural Gas Company, provide natural gas service to the Municipality of Anchorage and portions of the Matanuska-Susitna and Kenai Peninsula Boroughs. Buyer desires to purchase Gas to meet the needs of ENSTAR's customers.

C. Buyer desires to purchase such Natural Gas on an Interruptible basis; and

D. The Parties wish to provide the terms and conditions for the sale and purchase of such Natural Gas.

AGREEMENT

1. DEFINITIONS.

1.1 The following definitions apply to this Agreement:

"Agreement" is defined in the first paragraph hereof.

"Alaska Time" means Alaska Daylight Time when Daylight Saving Time is in effect and Alaska Standard Time when Daylight Saving Time is not in effect.

"Business Day" means any Day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business.

"Buyer" is defined in the first paragraph of this Agreement.

"Claim" means any claim, liability, loss, demand, damages, lien, cause of action of any kind, obligation, costs, royalty, fees, assessments, penalties, fines, judgment, interest and award (including recoverable legal counsel fees and costs of litigation of the party asserting the Claim), whether arising by law, contract, tort, voluntary settlement or otherwise.

"Continuous Rate" means the rate per hour, delivered without significant variation. For example, if 6,000 Mcf of Natural Gas is delivered in a Day at a substantially constant rate, the Continuous Rate would be 250 Mcf.

"Daily Quantity" has the meaning set forth in Section 2.2.

"Day" means a 24-hour calendar day.

"Delivery Point" is defined in Section 3.1.

"Dispute" means any dispute or controversy arising out of this Agreement including a Claim under this Agreement and any dispute or controversy regarding the existence, construction, validity, interpretation, enforceability, or breach of this Agreement.

"Effective Date" is defined in the first paragraph of this Agreement.

"Gas" or "Natural Gas" means any mixture of hydrocarbons or of hydrocarbons and non-combustible gases, in a gaseous state consisting primarily of methane and meeting the quality specifications of Section 5.2.

"Gas Sales Price" means the price per Mcf for Gas delivered in a Transaction, as set forth in Section 6.1.

"Interrupt," "Interruptible," or "Interruption" means, in the case of Seller's obligations, Seller's reduction or cessation of the delivery of Gas when Seller in its sole discretion elects to reduce or cease deliveries for any reason and, in the case of Buyer's obligations, Buyer's reduction or cessation of the receipt of Gas when Buyer in its sole discretion elects to reduce or cease receipt for any reason.

"Mcf," "MMcf" and "Bcf" mean thousand standard cubic feet, million standard cubic feet, and billion standard cubic feet, respectively. Standard conditions will be at 14.65 psia pressure, and 60 degrees Fahrenheit temperature.

"MMcfpd" means million standard cubic feet per Day.

"Month" means a period beginning at 12:00:00 a.m., Anchorage time, on the first Day of a calendar month and ending at 11:59:59 p.m., Anchorage time, on the last Day of the same calendar month.

"Operational Notice" means a notice given as provided in Sections 2.2, 2.3, 2.4, 3.1, and 14.2.

"Party" and "Parties" are defined in the first paragraph of this Agreement.

"Production Taxes" has the meaning defined and set by AS 43.55.011, as amended, replaced, or supplemented from time to time after the date hereof.

"Seller" is defined in the first paragraph of this Agreement.

"Term" is defined in Section 4.1.

"Transaction" means an individual agreement to sell and purchase Gas reached by the Parties pursuant to Section 2.1.

"Transaction Confirmation" means the documentation memorializing each Transaction, including the commencement and termination dates of the sale and purchase of Natural Gas, the total volume of Gas, the Daily Quantity, the Continuous Rate, the Delivery Point, the Price of Gas purchased and sold, and any other terms of sale, in the form attached as Exhibit A.

2. GAS SALES AND PURCHASES.

2.1 **Sale and Purchase.** Subject to all terms and conditions of this Agreement, at any time during the Term, either Party may propose to buy or sell Gas, as applicable, on an Interruptible basis at a certain volume and price. If both Parties agree to a Transaction for an Interruptible Gas sale and purchase, they shall memorialize the Transaction by executing a Transaction Confirmation containing the key terms. In the event the Parties cannot reach mutual agreement on the terms governing a purchase or sale of Gas, then neither Party shall be obligated to deliver or receive, as applicable, any Gas on an Interruptible basis.

2.2 **Daily Quantity**. Seller shall deliver to Buyer the Daily Quantity of Gas at the rate and for the duration mutually agreed by the Parties as set forth in a Transaction Confirmation or as modified through an Operational Notice. Buyer will communicate with Seller, by emailed Operational Notice, by 12 pm Alaska Time each Day, its anticipated Natural Gas scheduling needs for the following Day. If any event or circumstance that may affect deliveries or receipts of Natural Gas under this Agreement becomes known to a Party, it shall provide as much advance notice to the other Party as is commercially reasonable under the circumstances at the time.

2.3 **Volume and Volume Variations.** Buyer and Seller understand that this Agreement may require frequent communication and cooperation for proper scheduling and delivery of Gas. Unless otherwise set forth in an Operational Notice, daily delivery of Gas volumes nominated shall be delivered at a Continuous Rate. The acting Party will provide twenty-four (24) hours prior notice through Operational Notices to the other Party when as permitted by this Agreement: (i) Buyer changes its Continuous Rate, or (ii) Seller Interrupts deliveries or Buyer Interrupts receipts.

2.4 **Operational Notices and Documentation**. Actions under Sections 2.1 and 2.3 will be made or confirmed through Operational Notices. The Parties will document the commencement and termination of all sales and purchases of Gas, and any modifications of the rates of flow within a reasonable time after the applicable Operational Notice. The transactional summaries will be tabulated by Seller in a spreadsheet that will be provided to Buyer periodically or in response to a request and will contain at least the following information in relation to each such transaction: (a) the total volume of sales and purchases of Gas, (b) the applicable rate(s) of Gas delivery, (c) the applicable Delivery Point(s), (d) the applicable Gas Sales Price, and (e) the total amount due.

2.5 **Transportation.** Seller is solely responsible for arranging the logistics of transporting Natural Gas sold under this Agreement to the Delivery Point. Buyer is solely responsible for arranging the logistics of transporting Natural Gas sold under this Agreement from the Delivery Point.

3. DELIVERY POINT; TITLE; LIABILITY AND RISK OF LOSS.

3.1 The authorized Delivery Point(s) for each Transaction will be mutually agreed to by the Parties for each Transaction and shall be set forth in a Transaction Confirmation and, if modified, through an Operation Notice.

3.2 Title to all Gas delivered under this Agreement will pass from Seller to Buyer upon the delivery of such Gas by Seller to Buyer at the applicable Delivery Point(s). For the avoidance of doubt, with respect to all such delivered Gas, Buyer shall have the right to use Gas sold and purchased pursuant to this Agreement for any purpose.

3.3 All cost, liability and risk associated with the Gas will be with Seller prior to delivery by Seller to the applicable Delivery Point(s), and with Buyer after delivery by Seller to the applicable Delivery Point(s).

4. EFFECTIVE DATE AND TERM.

4.1 **Term.** This Agreement is effective on the Effective Date and, unless earlier terminated under Article 8, terminates August 31, 2027 (the "Term").

4.2 **Survival.** Notwithstanding anything to the contrary, all provisions of this Agreement relating to accrued payment obligations, indemnification, limitation of liability, and dispute resolution, including Sections 3.2, 3.3, 4.2, and Articles 1, 7, 8, 9, 10, 11, 13, 21, and 22, will survive expiration or termination of this Agreement.

5. MEASUREMENT; QUALITY.

5.1 The American Gas Association (AGA) measurement standards in effect on the date of delivery will apply to all Gas delivered under this Agreement.

5.2 Seller warrants all Gas delivered to the applicable Delivery Point(s) will be of a pressure, condition and quality to meet the standard requirements of the receiving pipeline system.

6. GAS SALES PRICE; OTHER COSTS.

6.1 **Gas Sales Price.** The sale price for each Transaction will be mutually agreed to by the Parties for each Transaction and shall be set forth in a Transaction Confirmation. All payments for purchased Gas will be made in accordance with Section 7.

6.2 **Production and Transportation Costs.** Seller is responsible for all Natural Gas processing and treatment expenses, royalties, severance/ production taxes, transportation costs (if any), and all other costs related to Natural Gas prior to the Delivery Point. Seller assumes all risk of future or retroactive changes in severance/ production taxes, excess royalties and any associated interest and penalties that might be assessed on the Natural Gas sold pursuant to this Agreement

6.3 **Post-Delivery Costs.** Buyer is responsible for all taxes, transportation costs, and any and all other costs related to the Natural Gas beyond the Delivery Point.

7. INVOICING AND PAYMENT.

7.1 **Statement and Payment.** On or before the twenty-fifth (25^{th}) day of the month following the month of delivery of Natural Gas hereunder, Seller will provide Buyer at the address set forth below an invoice setting forth the volume of Natural Gas delivered to Buyer during the preceding month and the amount owed for such Natural Gas. Buyer will make payment by wire transfer within fifteen (15) days of delivery of the invoice. Payment will be by Automatic Clearing House transfer to the account of Seller set forth below.

Seller:
BlueCrest Alaska Operating LLC
1320 S. University Drive, Suite 825
Fort Worth, TX 76107
Contact: John M. Martineck
Telephone: 214-697-880
Email: John.Martineck@BlueCrestEnergy.com

Remittance information:
BlueCrest Alaska Operating LLC

ACH & Wire Information:
Physical Mailing Address:
JP Morgan Chase Bank, N.A.

Wire Routing: 021000021
Account Name: BlueCrest Alaska Operating LLC
Account Number: 709423776
ABA/Routing: 111000614

7.2 **Interest.** Any undisputed amount not paid when due (or any overpayment) will accrue interest daily at the daily rate corresponding to the annual rate of interest that is two (2) percentage points greater than the Wall Street Journal prime rate at the due date for payment or, if lower, the maximum rate of interest allowed under applicable law. If Buyer withholds payment of a disputed amount and it is later determined that all or part of the disputed amount was correctly invoiced, such amount that was properly payable shall accrue interest as set forth in this section. If an amount is disputed, but timely paid, and all or part of that amount is determined to have been incorrectly invoiced, the overpayment reimbursement due to Buyer will accrue interest as set forth in this section.

7.3 **Audit.** Each Party to this Agreement, at its sole expense, will have the right to audit the books and records of the other Party relating to performance of this Agreement. All audits will be conducted in accordance with professional auditing standards and during normal business hours. The audited Party will fully cooperate with the auditing Party to accomplish the audit as expeditiously as possible. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments to previous billings shall be paid in full by the Party owing payment within thirty (30) Days of notice from the other Party and substantiation of such adjustments.

8. TERMINATION.

8.1 The Parties agree this Agreement is a forward contract within the meaning of and for the purposes of the United States Bankruptcy Code, as amended. Further each Party represents to the other Party that it is a forward contract merchant as such term is defined in and for the purposes of the Bankruptcy Code, as amended. If: (a) a Party becomes the subject of bankruptcy or other insolvency proceedings, or proceedings for the appointment of a receiver, trustee, or similar official, (b) a Party becomes generally unable to pay its debts as they become due, or (c) a Party makes a general assignment for the benefit of creditors, the other Party to this Agreement may suspend its performance hereunder and or terminate this Agreement effective on notice to the other Party.

8.2 In the event that: (a) either Party defaults in its undisputed payment obligations, or (b) either Party defaults in its performance of any other material obligation hereunder; and (i) in the case of a default under Section 8.2(a), the non-defaulting Party has given notice to the defaulting Party of such default and the defaulting

Party has not cured such default within thirty (30) Days from the date it receives the notice to cure such default, or (ii) in the case of a default under Section 8.2(b), the non-defaulting Party has given notice to the defaulting Party specifying the default and the defaulting Party has not cured such default within sixty (60) Days from the date it receives the notice to cure such default, then the non-defaulting Party has the right to withhold or suspend deliveries or payment, or terminate this Agreement, each in the sole discretion of the non-defaulting Party, effective on notice to the other Party.

9. TAXES.

9.1 **General Allocation.** Seller will pay all taxes, fees, penalties, and assessments (including Production Taxes) attributable to Gas or any other activity or facility prior to the Delivery Point, but not Excess Taxes. Buyer will pay all taxes, fees, penalties, and assessments attributable to Gas or any other activity or facility at or after the Delivery Point.

9.2 **New Production Taxes and Financial Incentives**. Notwithstanding anything in Section 11.1 to the contrary, Seller shall be responsible for any production taxes attributable to its operations and transactions. Seller shall be responsible for any changes in the State of Alaska's financial incentives or credits from the financial incentives or credits in place on the Effective Date, including, without limitation, any changes in the financial incentives or credits contained in AS 43.55 et seq.

10. ROYALTIES.

10.1 Seller will be responsible for the payment of all royalties and any fees, penalties and assessments attributable to the royalties on Gas delivered under this Agreement. If Gas sold under this Agreement is produced from land owned by the State of Alaska, Seller is responsible for obtaining acceptance by the Alaska Department of Natural Resources of the Gas Sales Price paid under this Agreement as to the value of the State's royalty share of production under AS 35.05.180(aa).

10.2 If and to the extent that any one or more royalty owners of the Gas purchased by Buyer from Seller requires Seller under applicable laws, regulations, or lease terms to pay royalties on Gas sold hereunder at a value that exceeds the applicable Gas Sales Price under this Agreement, Buyer shall reimburse Seller the "excess royalties" that Seller pays to royalty owners. For clarification, the "excess royalties" referred to in the previous sentence shall be calculated as the product of: (1) the value of Gas for purposes of royalty payments less the actual sales price; (2) the applicable royalty percentage; and (3) the volume of Gas sold to which the royalty percentage applies.

10.3 If and to the extent that the State of Alaska elects under applicable laws, regulations, or lease terms to take its royalty in kind, then Seller will have the right, in its sole

discretion, to reduce Seller's obligations under this Agreement, provided, however, that, Seller shall give Buyer no less than 30 Days' prior notice of any such event and Seller and Buyer shall then meet to work out in good faith a reasonable reduction to the Gas volumes to be provided by Seller under this Agreement.

11. WARRANTY OF TITLE.

11.1 Seller warrants title at the Delivery Point to all Natural Gas delivered to Buyer hereunder and warrants its right to deliver and sell same, and agrees to hold Buyer harmless from and indemnify it against any and all loss, damage, cost, expense, or liability of whatsoever kind arising out of Claims of third persons, including Bankruptcy trustees, with respect to the title to such Natural Gas and or the right to sell and deliver such Natural Gas, including costs, expenses, and reasonable attorney's fees incurred by Buyer in defending against any such Claims.

12. SUCCESSORS AND ASSIGNS.

12.1 This Agreement shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties hereto, save that no assignment or other transfer of this Agreement or any interest hereunder by either Party shall be effective without the written consent of the other Party (which consent shall not be unreasonably withheld), and the assignee must, in the commercially reasonably opinion of the other Party, be financially and physically capable of assuming such obligations. No assignment for which written consent has been received will be effective until the assignee agrees in writing to assume and fully perform the terms of this Agreement.

13. INDEMNIFICATION; LIMITATION OF LIABLITY.

13.1 **Indemnification.** Each Party will protect, defend, indemnify, and hold harmless the other Party from any and all liability and expense, including costs, expenses, and reasonable attorney's fees incurred, on account of all Claims asserted by third persons, including for damages to and destruction of property, and injury to and death of persons, arising from any act or accident including a failure to act, as to which and to the extent that the indemnifying Party was at fault (whether through negligence, willful misconduct, strict liability or other legal theory) in connection with the installation, presence, maintenance, and operation of property, equipment, and facilities of the indemnifying Party used in connection with or associated with the Natural Gas sold and purchased hereunder. This duty to protect, defend, indemnify, and hold harmless will survive the expiration or termination of this Agreement. Without limiting Section 13.1, as between Seller and Buyer, Seller will be liable for all claims that arise from the failure of Gas delivered by Seller to Buyer under this Agreement to meet the quality requirements of Section 5. Neither Party will be liable to the other for special, punitive, indirect, or consequential damages resulting from or arising out of or occurring in connection with this Agreement.

13.2 **Limitation of Liability.** Neither Party will be held liable to the other for special, punitive, indirect, or consequential damages resulting from or arising out of or occurring in connection with this Agreement.

14. NOTICES.

14.1 Except as specifically provided otherwise in Article 7 of this Agreement, all notices and communications under this Agreement (other than Operational Notices as provided in Section 14.2) will be made in writing by certified mail (return receipt requested), facsimile (with confirmation by one of the other means described herein received within two (2) Business Days of receipt of such facsimile), email, or by nationally recognized overnight courier. All such notices will be deemed effective (a) if mailed, on the date indicated on the returned receipt, (b) if delivered personally or by overnight courier, when delivered, (c) if sent by email or by facsimile during the normal business hours of the recipient, on the same Business Day as sent, and (d) if sent by email or facsimile after the normal business hours of the recipient, on the next Business Day following the date of transmission.

Seller
BlueCrest Alaska Operating LLC
Attn: John M. Martineck
Physical: 1320 S. University Drive, Suite 825
Fort Worth, TX 76107
Telephone: 214-697-8802
Email: John.Martineck@BlueCrestEnergy.com

Buyer
Alaska Pipeline Company
Attn: Inna Johansen, Vice President, Regulatory & Gas Supply
Physical: 3000 Spenard Road
Anchorage, AK 99503
Mailing: P.O. Box 190288
Anchorage, AK 99519
Email: inna.johansen@enstarnaturalgas.com

14.2 Any Operational Notice required or permitted to be given to either Party will be given by telephone and confirmed by email, at the telephone numbers and email addresses set forth below (or such other telephone numbers and email addresses as the Parties may designate from time to time by written notice under Section 14.1). Notices given by telephone will be effective immediately and the confirmation by email will be effective when received by the recipient's email server. The Party providing an Operational Notice will attempt to contact the primary contact first. If the primary contact is unavailable to receive notice in a timely manner, the Party providing an Operational Notice will contact the alternate contact.

Seller:
BlueCrest Alaska Operating LLC
1320 S. University Drive, Suite 825
Fort Worth, TX 76107

Primary Contact:
John M. Martineck
President & Chief Operating Officer
Telephone: 214-697-8802
Email: John.Martineck@BlueCrestEnergy.com

Alternate Contact:
Mike Carne
Corporate Controller
Telephone: 817-509-1214
Email: MCarne@BlueCrestEnergy.com

Buyer:
Alaska Pipeline Company
3000 Spenard Road
Anchorage, AK 99503

Primary Contact(s):
Inna Johansen
Vice President, Regulatory & Gas Supply
Telephone: 907-334-7830
Email: inna.johansen@enstarnaturalgas.com

Jamie Stout
Gas Control Supervisor
Telephone: 907-334-7795
Email: Jamie.stout@enstarnaturalgas.com

14.3 Either Party may designate address changes by formal written notice as provided in Section 14.1.

15. NO THIRD PARTY BENEFICIARIES.

15.1 This Agreement is made for the sole benefit of the Parties and their respective successors and assigns. The Parties do not intend to create, and this Agreement will not be construed to create, by implication or otherwise, any rights in any other person or entity not a Party to this Agreement, and no such person or entity will have any rights or remedies under or by reason of this Agreement, or any right to the exercise of any right or power hereunder or arising from any default hereunder.

16. ENTIRE AGREEMENT; AMENDMENT.

16.1 This Agreement is the entire and complete agreement between the Parties regarding the sale and purchase of Gas as described herein. Any prior agreements or understandings, oral or written, are superseded and replaced by this Agreement. This Agreement may not be amended except in a writing duly executed by the Parties.

17. NO WAIVER.

17.1 Waiver of any default under this Agreement will not act as a waiver of any other or future default.

18. INTERPRETATION OF AGREEMENT.

18.1 Each Party acknowledges and agrees that it has participated in the drafting of this Agreement and has had the opportunity to consult with legal counsel and any other advisors of its choice to its satisfaction regarding the terms and provisions of this Agreement and the results thereof. As a result, the rule of construction that an agreement be construed against the drafter will not be asserted or applied to this Agreement.

19. NO PARTNERSHIP.

19.1 The execution and performance of this Agreement is not intended by the Parties to create and will not be construed to create any partnership or business association between the Parties.

20. HEADINGS.

20.1 The headings in this Agreement are for the convenience of the reader only. The headings are not part of this Agreement and do not purport to and will not be deemed to define, limit, or extend the scope or intent of the article or section to which they pertain.

21. AUTHORITY.

21.1 Each Party represents and warrants to the other Party that it has the legal authority to enter into and perform this Agreement and each obligation assumed by such Party under this Agreement.

22. GOVERNING LAW AND DISPUTE RESOLUTION.

22.1 **Governing Law.** This Agreement is governed by and interpreted under the laws of the State of Alaska, without regard to its choice of law rules.

22.2 **Resolution of Disputes.** The Parties shall exclusively and finally resolve any Dispute between them using direct negotiations and/or non-jury trials, all as set out in this Article 22. A Party who violates this Article 22 shall pay all reasonable legal, expert and court fees and costs incurred by the other Party in any suit, action, or proceeding to enforce this Article 22. While the procedures in this Article 22 are pending, each Party shall continue to perform its obligations under this Agreement, unless to do so would be impossible or impracticable under the circumstances.

22.3 **Direct Negotiations**. If a Dispute arises, a Party shall initiate the resolution process by giving notice setting out in writing and in detail the issues in Dispute and the value of the Claim to the other Party. If a Party refuses to toll all applicable statutes of limitations and defenses based upon the passage of time while the proceedings in this Section 22.3 are pending, the other Party may file a court proceeding under Section 22.4 in an attempt to preserve its Claim and such proceeding shall be stayed by the arbitrator or arbitrators after appointment so that the Parties may continue efforts to resolve this Dispute as set out in this Section 22.3. A meeting between the Parties, attended by individuals with decision-making authority, must take place within twenty (20) days from the date the notice was sent in an attempt to resolve the Dispute through direct negotiations.

22.4 **Trial**. If the Dispute is not resolved by mediation within thirty (30) days from the date of the notice requiring direct negotiations, then the Dispute will be resolved by the state or federal courts of Alaska in Anchorage, Alaska. Each Party, to the extent permitted by law, knowingly, voluntarily, and intentionally waives its right to a trial by jury in any action or other legal proceeding arising out of or relating to this Agreement and the transactions it contemplates. This waiver applies to any action or legal proceeding, whether sounding in contract, tort, or otherwise. All reasonable attorneys' and court fees and costs of both Parties shall be borne by the Party determined by the court to be at fault.

22.5 **Enforcement.** Proceedings to enforce judgment entered on an award may be brought in any court having jurisdiction over the person or assets of the non-prevailing Party. The prevailing Party may seek, in any court having jurisdiction, judicial recognition of the award, or order of enforcement or any other order or decree that is necessary to give full effect to the award.

23. CONFIDENTIALITY

23.1 Each Party shall, and shall cause its affiliates to, hold, and shall use its reasonable best efforts to cause its or their respective representatives to hold, in confidence any and all information, whether written or oral, concerning the subject matter of this Agreement, except to the extent that the disclosing Party can show that such information (a) is generally available to and known by the public through no fault of the disclosing Party, any of its affiliates or their respective representatives; (b) has been disclosed to any government commission, agency or organization; or (c) is lawfully acquired by the disclosing Party, any of its affiliates or their respective representatives from and after the date of this Agreement from sources which are not prohibited from disclosing such information by a legal, contractual or fiduciary obligation. Notwithstanding the foregoing, the Parties agree that disclosure may be made: (i) in order to enforce any of the provisions of this Agreement, including, without limitation, the agreement to arbitrate, any arbitration order or award and any court judgment; (ii) to the auditors, legal advisors, insurers, lenders, financial advisors, and affiliates of that Party to whom the confidentiality obligations set out in this Agreement shall extend; (iii) whether that Party is under a legal or regulatory obligation to make such disclosure, but limited to the extent of that legal obligation; (iv) with the prior written consent of the other Party; or (v) as required in connection with RCA or Alaska Department of Natural Resources approvals.

24. EXECUTION IN COUNTERPARTS; TIMING OF EXECUTION.

24.1 This Agreement may be executed by the Parties in any number of counterparts and on separate counterparts, including electronic transmittals, each of which when so executed will be deemed an original, but all such counterparts, when taken together, will constitute but one and the same Agreement. In the event one Party executes the Agreement, and the other Party does not execute the Agreement within ten (10) days of the first Party's execution, the execution of the Agreement by the first Party will be deemed null and void.

25. CONFLICT OF INTEREST.

25.1 No Party, nor any director, employee, or agent of a Party will give to or receive from any Party or any director, employee, or agent of the other Party any commission, fee, rebate, gift, or entertainment of significant cost or value in connection with this Agreement. Each Party will promptly notify the other Party of any violation of this section, and any consideration received by a Party as a result of such violation will be paid over or credited to the other Party. Each Party, or its designated representative(s), may audit any and all records of the other Party as provided in Section 7.3 of this Agreement for the sole purpose of determining whether there has been compliance with this section.

IN WITNESS WHEREOF, the Parties have executed this Gas Sale and Purchase Agreement effective as of the Effective Date.

SELLER:	**BUYER:**
BlueCrest Alaska Operating LLC	**Alaska Pipeline Company.**
Signature:	**Signature:**
Name: John M. Martineck	**Name:** John D. Sims
Title: President & Chief Operating Officer	**Title:** President

EXHIBIT A

TRANSACTION CONFIRMATION

This Transaction Confirmation is subject to the Gas Sale and Purchase Agreement between Seller and Buyer, dated _____.

SELLER:	**BUYER:**
BlueCrest Alaska Operating LLC	Alaska Pipeline Company
Attn: John M. Martineck	Attn: _____
Phone: 214-697-8802	Phone: _____
Email: John.Martineck@BlueCrestEnergy.com	Fax: _____

PERIOD:

Transaction Start Date: _____ Transaction End Date: _____

GAS PRICE:

Gas Price: _____ $/Mcf

GAS QUANTITY:

Gas Quantity:

Interruptible: _____ Mcf at a rate of _____ Mcfpd

DELIVERY POINTS:

SPECIAL CONDITIONS:

Seller: BlueCrest Alaska Operating LLC	Buyer: Alaska Pipeline Company
By: _____	By: _____
Title: _____	Title: _____
Date: _____	Date: _____

TRANSACTION CONFIRMATION

Interruptible #10 TC#1

This Transaction Confirmation is subject to the Gas Sale and Purchase Agreement between Seller and Buyer, effective 09/01/2026.

SELLER:	**BUYER:**
BlueCrest Alaska Operating LLC	Alaska Pipeline Company
Attn: John M. Martineck	Attn: Inna Johansen
Phone: 214-697-8802	Phone: 907-334-7830
Email: John.Martineck@BlueCrestEnergy.com	Email: inna.johansen@enstarnaturalgas.com

PERIOD:

Transaction Start Date: 09/01/2026 Transaction End Date: 08/31/2027

GAS PRICE:

Gas Price: $12.30/Mcf

GAS QUANTITY:

All gas produced and available for sale up to 30,000 Mcf/day from new wells developed between September 1, 2025 through August 31, 2027.

DELIVERY POINTS: BlueCrest Cosmo Pipeline Connection (ENSTAR/ APC MSN K694)

SPECIAL CONDITIONS: APC's commitment to purchase gas volumes under TC#1 is contingent on ENSTAR securing adequate firm storage capacity.

Seller: BlueCrest Alaska Operating LLC	Buyer: Alaska Pipeline Company
By: _____	By: _____
Title: President and Chief Operating Officer	Title: President
Date: January 1, 2026	Date: 1/2/2026

THE STATE of ALASKA
GOVERNOR MIKE DUNLEAVY

Department of Natural Resources
OFFICE OF THE COMMISSIONER

550 West 7th Avenue, Suite 1400
Anchorage, AK 99501-3561
Main: 907.269-8431
Fax: 907-269-8918

January 9, 2026

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501-3469

Re: ENSTAR Natural Gas Storage Development

Dear RCA Commissioners:

The Alaska Department of Natural Resources (DNR) writes to share its support of ENSTAR's efforts to develop additional storage in the Cook Inlet.

The mission of DNR is to develop, conserve, and maximize the use of Alaska's natural resources consistent with the public interest. ENSTAR's proposed storage project has the potential to support this mission by utilizing a nearly depleted natural gas reservoir to expand gas storage in the Cook Inlet. This project could extend the useful life of these assets indefinitely for the benefit of Alaskans and expand the available storage capacity to allow additional natural gas production in the basin to be developed and injected into the facility. ENSTAR's project has the potential to maximize this natural resource to its fullest extent, benefiting the State, Alaska residents, and regional utilities.

DNR will be reviewing the technical merits of this project through a separate process but generally supports ENSTAR's concept to meet the Cook Inlet Basin's future gas storage needs by leveraging existing infrastructure to extend the useful life of otherwise mature oil and gas leases. Any such project could be a critical asset in the Cook Inlet Basin for decades. DNR has a strong interest in all such projects and their potential to support continued production and utilization of Cook Inlet gas.

Sincerely,

John Crowther
Commissioner-designee

BlueCrest Alaska Operating LLC

3301 C Street, Suite 202
Anchorage, AK 99503
(214)697-8802

John M. Martineck
Chief Operating Officer

January 6, 2026

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501-3469

Re: ENSTAR Natural Gas Company – Request for Prudency Determination for Gas Storage Project

Dear Commissioners:

BlueCrest Alaska Operating LLC ("BlueCrest") respectfully submits this letter in support of ENSTAR Natural Gas Company's request for a predetermination of prudency associated with the development of additional natural gas storage capacity in Cook Inlet.

BlueCrest has operated in Alaska for many years and is actively developing oil and gas resources in the Cosmopolitan Unit within the Cook Inlet Basin. These resources would make a meaningful contribution to Southcentral Alaska's natural gas supply; however, one of the principal challenges to bringing additional gas to market has been the limited flexibility of existing storage infrastructure. Historically, utilities have required firm contractual commitments, while producers must balance deliverability risk, development timing, and capital investment.

Through collaborative discussions, ENSTAR and BlueCrest have structured a gas sales framework that addresses these constraints. Under this arrangement, BlueCrest anticipates the ability to deliver up to 30,000 MCF per day (approximately 10.95 BCF per year) on an interruptible basis for an initial one-year term following the completion of two new development wells. While BlueCrest believes this level of deliverability exists, confirmation through drilling is required before such volumes can be contractually committed on a firm basis.

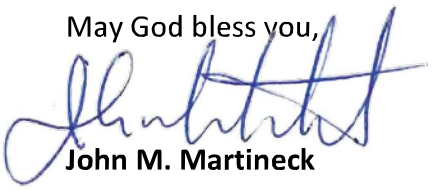
The proposed storage project is a critical enabling element of this arrangement. Additional storage capacity would allow ENSTAR to better align supply availability with seasonal demand, enhance system reliability, and accept incremental gas volumes as they become available. From BlueCrest's perspective, access to expanded storage is essential to justify continued investment in Cook Inlet gas development, as it provides a reliable outlet for new production that would otherwise be constrained.

Approval of ENSTAR's request will benefit ratepayers by improving supply reliability and market flexibility while encouraging new in-basin production at reasonable cost. The storage facility will

also provide long-term value to the Cook Inlet gas market by supporting future development and mitigating supply volatility for decades to come.

BlueCrest is committed to continued investment in Alaska and strongly supports ENSTAR's request for a prudency determination. We respectfully encourage the Commission to act expeditiously so that the storage project may proceed on schedule and support new gas development beginning in 2026.

May God bless you,



John M. Martineck
President and Chief Operating Officer
BlueCrest Alaska Operating LLC

March 2025

GEAR TASK FORCE
GAS STORAGE OPPORTUNITIES RECOMMENDATION

Storage has long played an essential operational and reliability role in acting as an effective tool for bridging differences in supply and demand across many different time periods and will remain essential in managing our energy system for decades to come. It is also effective in mitigating the effects of price spikes, which supports greater affordability. Storage development is underpinned through long-term financial commitments which can present a challenge for generators that lack scale and regular opportunities to operate. While there are significant costs and operational limitations to the deployment of new storage facilities, it remains the best method to mitigate situations where there are spikes in demand and/or disruptions to fuel gas supply. Therefore, it is critical for all stakeholders to evaluate and implement sufficient storage options of all types.

Storage can mean many different things to many different people. The use of the word herein is meant to be construed as broadly as possible. Among the qualifying uses of the term are, of course, underground natural gas storage, but it should also incorporate other forms of back up alternatives including alternate fuel/diesel/oil tanks at a power plant, LNG or CNG to the extent it is usable by a generator in lieu of natural gas transported via pipelines, batteries, compression storage, and other methods for storing electricity, thermal energy storage, and any other technology that allows the grid to stay reliable when the natural gas demand is high.

This context considers storage as a solution to effectively manage short-term supply and demand issues, namely unexpected surges in demand. Storage is also a great derisking asset that offers multiple operational and economic benefits to natural gas storage holders and gas and electric system operators, even during normal operations.

Recommendation

GEAR recognizes the critical role of storage in supporting energy system reliability and recommends that states and organized power markets evaluate a wide array of solutions that affect the investment in, development of, and use of storage of all types, including associated infrastructure, to support the electricity grid and end use customer reliability under high energy demand conditions.

Regulators and RTOs/ISOs, namely those with resource adequacy and/or siting authority, should apply a strategic approach to expand opportunities for increased or new storage investment consistent with empowering end-users to exert greater control over supply needs. The following questions are intended to help assess the current state of and guide planning for future storage options, as well as help assess and compare current and projected energy demand/supply portfolio, specifically in relation to storage. State commissions may consider:

1. How much storage does your state/region have? What type is it? Where is it vis-à-vis market centers? What existing storage (and related gas transportation capacity) is available? Take an inventory of existing storage (both inter and intrastate), including the mapping of current storage capacity and deployment. This can help guide planning for future storage options.

2. What storage does your state/region need? The next step of this analysis would be to understand the capacity, deliverability, location and connectivity of storage required to meet reliability requirements. This would be scenario-based in response to possible percentage reductions in gas and power under stresses to the system. Looking at regions that suffered outages and applying those reductions as appropriate to identify gaps.

3. What new or expanded storage facilities are available at what cost? Publish a request for proposals (RFP), request for information (RFI), or request for solutions (RFS) (depending on the jurisdiction) to get a supply curve and construction timeframe for consideration. These requests should be technology agnostic to allow for the maximum number of potential projects and thereby the maximum amount of competition and information. Bidders may propose contracting for underground storage services, new tanks at their plants for back up fuel, etc. The more participation the better, as the commissions and/or other appropriate authorities can then analyze and evaluate across technologies based on cost, size, speed to market and any other relevant attributes. This approach is not intended to replace or frustrate existing storage development and contracting practices but rather serve as a supplement to ensure that opportunities are appropriately assessed and maximized.

4. What does it take to execute? Timing (e.g., urgency and development), permitting (e.g., construction constraints), cost/investment recovery (e.g., RTO products/ancillary services) are all critical considerations that may require additional regulatory support.

This analysis would need to account for possible differences in regulated jurisdictions, where regulators consider prudency or other features of storage as part of integrated resource planning, and other jurisdictions where it might require consideration outside of business-as-usual market frameworks that incentivize generators to invest in gas storage options (LNG, dual fuel, underground, etc.) as part of their overall supply portfolio.

Most new storage requires development and long-term commitments, up to a decade or more. Similar to the above actions taken by state commissions. Organized power markets should examine the role of storage in meeting reliability requirements and how changes to market rules can support generator's underwriting new or additional storage and firm contracting. This contracting can be either direct with storage providers or indirect through no-notice or non-ratable pipeline services or through marketers that hold storage. New ancillary services, changes in capacity accreditation or other solutions could be considered as ways to solve the problem of paying for the reliability needed, even in years when it is not called upon.

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	John M. Espindola, Chairman Steve DeVries Mark Johnston Robert M. Pickett John C. Springsteen
In the Matter of the Petition Filed by ENSTAR NATURAL GAS COMPANY, LLC for Advanced Determination of Decisional Prudence for Natural Gas Storage Project	Docket No. U-26-____

ENSTAR NATURAL GAS COMPANY'S PETITION FOR ADVANCED DETERMINATION OF DECISIONAL PRUDENCE FOR NATURAL GAS STORAGE PROJECT

AFFIDAVIT OF MATTHEW S. FEDERLE

AFFIDAVIT OF MATTHEW S. FEDERLE

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

Matthew S. Federle, being first duly sworn, deposes and says:

Introduction

1. My name is Matthew S. Federle. My business address is 5151 Fairbanks Street, Anchorage, Alaska 99503. I am the Director of Gas Plant Storage for ENSTAR Natural Gas Company, LLC ("ENSTAR" or "Company").

2. I am responsible for managing the facilities, infrastructure, services, and daily operations of the natural gas storage facility owned by Cook Inlet Natural Gas Storage Alaska, LLC's ("CINGSA"). ENSTAR provides services to CINGSA under the terms of the Operation and Maintenance Agreement between the two parties executed on July 30, 2010. I have worked at the CINGSA facility since 2011 and have been the Director of Gas Plant Storage since 2020. I have served on the American Gas Association Underground Storage Committee since 2019. Most recently, I led the CINGSA expansion project, which increased storage and deliverability capabilities and added surface facilities. For that project, I supported the design, managed on-site contractors, logistics, and vendors, and developed and managed the project budget. For the last 29 years, I have been actively involved in aspects of project management, design, construction, and the operations and maintenance of gas storage facilities. Prior to joining ENSTAR, I worked at American Natural Resources ("ANR"), a TC Energy Company,

from 1996 to 2011. Starting at an entry level mechanical position I advanced to a cross-functional technical position. I completed many projects during my time with ANR, including the Keystone pipeline pump stations in South Dakota and a business development endeavor to align the Standard Operating and Maintenance Procedures of five companies into one unified plan. Prior to starting my career in the natural gas storage industry, I served in the United States Navy from 1989-1995, during Desert Shield and Desert Storm, in engineering. I earned the Navy Achievement Medal, National Defense Service Medal, and a Southwest Asia Service Medal with two bronze stars. My resume is attached as Exhibit MSF-1.

3. I have not previously provided testimony before the RCA, but I regularly present to the Regulatory Commission of Alaska ("RCA") during scheduled public meetings, and annually to Alaska Department of Natural Resources ("DNR") staff, providing updates on CINGSA's facilities and operations.

4. The purpose of my affidavit is to support ENSTAR's request for an advance determination that the Company's decision to develop a natural gas storage facility that will be integrated with its utility system (the "Project") is prudent, in the public interest, and consistent with the Company's obligations under the Alaska Public Utilities Regulatory Act. In particular, I will address the plan, design, engineering, cost estimates, management, and development schedule for the Project.

5. I, or those under my direct supervisions, have reviewed all of the source material referenced in the citations in this affidavit. The references and quotes are true and correct representations of those materials.

Plan for the Project

6. ENSTAR plans to convert the nearly depleted Upper Tyonek Pool of the Kenai Loop Unit in the Kenai Peninsula Borough (the "Reservoir") into an underground natural gas storage reservoir with associated surface facilities. The Reservoir has produced approximately 29 billion cubic feet ("Bcf") of gas since being discovered. Initially, the Reservoir will have a total storage volume of approximately 25 Bcf, consisting of 17 Bcf of working gas (gas available for withdrawal) and 8 Bcf of base gas. Base gas is the volume of gas necessary to keep the Reservoir pressurized to support withdrawal deliveries.

7. ENSTAR proposes to inject gas into the Reservoir by utilizing three existing injection/withdrawal wells and two 5,000 horsepower natural gas engine-driven reciprocating compressors. The wells and station facilities consisting of compression, gas dehydration, filtration, and measurement facilities will be located off Marathon Road on property currently owned by the City of Kenai only 2.0 miles from the CINGSA facility location.

8. The Project is intended to initially provide 17 Bcf of working gas capacity. This is the volume that can be withdrawn for delivery to customers under initial maximum withdrawal rates of approximately 50 million cubic feet per day ("MMcfd"). This withdrawal will originally come from three existing wells ("KL 1-1," "KL 1-3," and "KL

1-4") that penetrate the Reservoir. The wells will be worked over to increase the deliverability by upsizing the production tubing from 2-7/8" to 4-1/2" to accommodate higher gas flow rates. Initial injection rates at the facility will be significantly higher due to the compression that ENSTAR plans to install, with the potential to achieve rates of up to 120 MMcfd. The fourth existing well located at the facility is KL 1-2. This well will be converted into a disposal well and will help to reduce annual operating costs over the life of the project. ENSTAR will also connect the facility to its existing Supervisory Control and Data Acquisition ("SCADA") system. This will give the Company the ability to leverage existing systems to monitor the pressure, temperature, and gas flow rate at each injection/withdrawal well from a central location. ENSTAR will also be able to integrate the SCADA information into the gas control system in Anchorage to provide around the clock oversight for operations and gas balancing.

9. The Project has been designed so that additional separation, dehydration, measurement, and storage injection/withdrawal wells can be accommodated, if future expansion in the facility is warranted. It is estimated that, following expansion, the facility's capacity could be increased to 32 Bcf total gas in place and that the maximum injection and withdrawal rates could be increased to 180 MMcfd if needed by local market demand.

10. As I mentioned above, three of the four existing wells at the Project site will be used for natural gas storage injections and withdrawals. One of the first priorities for this Project is to workover the three existing wells and establish a baseline assessment to satisfy the standards of the American Petroleum Institute's ("API") Recommended Practice 1171.

API 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," was first issued in September 2015 and was later incorporated by reference by the US Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA"), effective January 18, 2017. The regulations provide guidelines for safe natural gas storage in depleted reservoirs, covering design, construction, operation, monitoring, and maintenance to ensure reservoir and well integrity. Integrity data will be gathered while performing the workovers to establish the required baseline assessment prior to placing the wells into gas storage service. A critical component of the Project is to facilitate base gas injections into these three wells as early as possible to take advantage of available gas in the Cook Inlet that is waiting to be produced. To accomplish this goal, ENSTAR will utilize the existing on-site compressor to start injections immediately after bringing the first of the three wells into gas storage service.

11. The existing three candidate wellbores require rig workovers to increase the tubing size from 2-7/8" to 4-1/2". With the existing tubing removed, several logs will be ran in the wellbores as part of the baseline integrity assessment required by PHMSA. These logs will include ultrasonic wall thickness and caliper logs to assess the mechanical condition of the 7-5/8" intermediate and 4-1/2" production casing, cement bond logs to evaluate cement quality, and pulsed neutron logs to record a baseline for formation gas saturation. 4-1/2" tubing will then be run into the wellbore and landed into a tieback seal bore that currently exists in each well within the 7-5/8" intermediate liner top packer assembly.

Each well completion will additionally contain a sub-surface safety valve ("SSSV") set at approximately 150 feet below ground level, as required by the Alaska Oil and Gas Conservation Commission ("AOGCC"), and a chemical injection subset below the SSSV to allow methanol injection during well start-ups to mitigate hydrate formation. Mechanical integrity testing of the production tubing and production tubing annulus will be performed prior to installing 10,000 pounds per square inch rated trees on each well. A baseline assessment per API 1171 requirements will then be performed using all existing and obtained data prior to placing the wells into gas storage service. Attached as Exhibit MSF-2 to my affidavit are the current and future schematics that illustrate the work required to bring the wells in compliance with API 1171 standards.

12. Many gas storage wells produce some amount of water from the storage reservoir while withdrawing gas. The Kenai Loop has consistently produced steady volumes of water over its producing life, totaling approximately 13,000 barrels ("bbls") of produced water, or about 500 bbls of water for every 1 Bcf of gas withdrawn. Should the initial full volume of working gas (~17 Bcf) be produced over a year, this would equate to 8,500 bbls of water to dispose of annually. CINGSA has historically relied on third-party disposal services, and primarily sent its produced water to the Hilcorp Grind and Inject Facility at the Kenai Gas Field. In the last year, Hilcorp has greatly limited CINGSA's access to these third-party services. Currently, the only alternative is sending Class II produced water to Republic Services, which ships the water out of state at $121 per bbl. A disposal well will eliminate those operational costs.

13. KL 1-2 is an ideal disposal candidate for several reasons. The Tyonek sands at the KL 1-2 tested 100% water and are not in communication with the other three wells in the Kenai Loop Tyonek gas pool. As such, it is not a gas storage candidate. Similarly, additional testing of the shallower Beluga sands found only water with no gas and the well was temporarily abandoned after setting a downhole plug and pressure testing the casing. In 2012, Buccaneer permitted and obtained AOGCC approval to convert the KL 1-2 into a Class II disposal well with Aquifer Exemption Order 15 exempting the Sterling and Beluga Formations between the depths of 3,980' – 7,539' within a one half mile radius of the KL 1-2 wellbore.

14. Significant value exists in having the aquifer exemption approved and the wellbore in place. Converting the existing KL 1-2 wellbore to Class II disposal service requires permitting and obtaining an AOGCC Disposal Injection Order, performing a rig workover to install tubing and a packer, and installing surface facilities. Additionally, significant value can be added to the Project in the form of reduced annual operating cost. Based on $121 per bbl to dispose of produced water through Republic Services, and anticipated annual water production from the Project at 5,000-8,500 bbls, owning a Class II disposal well at the facility could save approximately $1,000,000 annually in water disposal costs.

15. To bring the new storage facility online at full capacity, ENSTAR will need to complete the following major activities:

- install two 5,000 horsepower natural gas engine-driven reciprocating compressors and their associated building, aerial coolers, piping, valves, lubricant and coolant storage tanks and process controls;
- acquire and inject base gas;
- install auxiliary support equipment, including emergency shut down systems, emergency generator, control systems, and communication systems for remote monitoring from Anchorage;
- install a recycle lube oil storage vessel (approximately 2,970 gallons) fabricated to the American Society of Mechanical Engineers ("ASME") Section VIII Code;
- install a lube oil storage vessel (approximately 2,970 gallons) fabricated to ASME Section VIII Code;
- install a 200-barrel ("Bbl") used oil storage tank fabricated to API standards;
- install a high-pressure gathering header from the wells to the compression/gas conditioning facility;
- install an ethylene glycol storage vessel (approximately 2,970 gallons), fabricated to ASME Section VIII Code;
- install two 400-Bbl produced water tanks (brine);
- install natural gas metering, regulation and separation equipment with their associated piping, valves, and process controls; and
- construct the operations footprint of the proposed pad, which will be approximately 15 acres.

16. As mentioned above, the Project is being designed with the potential for expansion of its storage capacity and withdrawal rates, but expansion of the facility will be driven and determined by market need and the needs of Customers.

17. The design will incorporate all relevant aspects of the CINGSA gas storage facility and will comply with existing International Building Code ("IBC") criteria, the Code of Federal Regulations, 49 CFR Part 192, and the Alaska Fire Code. The IBC outlines the design criteria for buildings, including criteria for seismic, wind, and snow loads. The federal regulations in 49 CFR Part 192 outline the design and operation of natural gas pipeline and storage facilities, including pipe, equipment, and emergency shutdown systems. The Alaska Fire Code outlines requirements for building ventilation, gas detection, and fire detection instruments. I have attached the preliminary surface facility design as Exhibit MSF-3. Depicted in red are the facilities to be installed with the initial Project. Items depicted in blue are potential expansion opportunities in the event of LNG deliveries.

18. The IBC design criteria, which will be used for the Project, were developed in response to the 1964 Good Friday earthquake in Alaska. Specifically, the IBC references the American Society of Civil Engineers ("ASCE") 7-22, Minimum Design Loads for Buildings and Other Structures. These are the appropriate standards to adhere to in designing structures such as the surface facilities for the proposed Project. In addition, this facility will use seismic switches and control logic similar to the equipment used at CINGSA's facility to provide an added layer of protection from seismic activity.

19. The Project will be similar in purpose and control philosophy as the CINGSA facility. Utilizing similar design criteria between the two projects will have multiple benefits. First, from a safety and reliability perspective, the CINGSA design has a proven 13-plus-year record of reliable service for Southcentral Alaska. With simultaneous construction and plant operations ("simops") taking place, operator familiarity with all components, equipment, and consistent operating procedures will allow for a safer, more efficient, and reliable project execution. The CINGSA operators have an excellent safety and project deliverability record for simops and the Project will directly benefit from that experience. Second, utilizing similar design and equipment allows for efficiencies in operating and maintenance. This deep understanding reduces operating costs and speeds up maintenance and problem-solving. Similar to the CINGSA design, the proposed Project will utilize high quality equipment with low failure rates to provide reliable service, thereby decreasing annual operating costs.

20. The Project will be operated utilizing the same ENSTAR employees and management team that currently operates CINGSA's assets under the Operating and Maintenance Agreement, leveraging existing Standard Operating Procedures ("SOPs"), policies, and best practices that have been developed to provide safe and reliable services at CINGSA. Two new operator positions and one supervisory position will be added to operate the new facility. Given CINGSA's proven design and SOPs, it is reasonable to rely on that experience to operate the Project.

Depleted Reservoir Storage

21. In 2009, ENSTAR commissioned an evaluation of Cook Inlet natural gas pools for the purpose of identifying potential pools available for natural gas storage. The evaluation was performed by TransCanada and screened 48 known gas pools across the Cook Inlet Basin, eleven of which were identified as prospective candidates worthy of additional review. Ultimately from this work, the Sterling C gas pool in the Cannery Loop Gas Field was identified, purchased, and converted to the gas storage facility now known as CINGSA. As discussed in the Affidavit of Mr. John D. Sims, in 2025, ENSTAR commissioned Arctic Slope Regional Corporation Consulting & Environmental Services, LLC ("ACES") to update the 2009 evaluation ("ACES Update"). Attached as Exhibit MSF-4 to my affidavit is the ACES Update.

22. The ACES Update revealed that of the 14 prospective candidates (three more prospective pools were identified by ACES in its review) identified with gas storage potential, one is now owned and operated by CINGSA, one is owned by AIX, and the other twelve are owned by Hilcorp (or Hilcorp affiliates) and are within fields under active development. The Kenai Loop Upper Tyonek Gas Pool, currently owned by AIX, was discovered in 2011, after the original 2009 study was conducted and was added to the list of potential gas storage candidates in the ACES Update. Of the 14 collective pools included in the 2025 update, the Kenai Loop Upper Tyonek Gas Pool is the only pool not currently in use for gas storage service and not in active development by Hilcorp. This is the site ENSTAR proposes to acquire and develop for the Project.

Estimated Construction Costs

23. ENSTAR's current estimated cost for developing the Project is approximately $240 million. This estimate was developed totaling costs associated with the potential acquisition and enhancement of the surface and subsurface facilities to provide utility grade natural gas storage service. The estimated costs for the surface facilities are approximately $75 million. This subtotal includes costs for compressors, dehydration equipment, metering, pipelines, land, and building construction, among other items. The subsurface estimate includes costs related to the reservoir, base gas, and well enhancements and totals approximately $165 million. The Company prepared these estimates using cost items from the budget for the original CINGSA project, and has refined them as it has acquired and evaluated information regarding the existing facility and infrastructure. For additional accuracy, ENSTAR applied escalation factors based on its experience with the 2024 CINGSA expansion project.

24. The Company's original estimate for developing the CINGSA facility was approximately $180 million for 11 Bcf of working gas capacity, or roughly $16.36 million per Bcf. ENSTAR ultimately completed the project for $161.4 million, or $14.67 million per Bcf. As mentioned above, the estimated cost for this proposed Project is approximately $240 million for 17 Bcf of working gas capacity, which equates to roughly $14.12 million per Bcf.

Project Schedule

25. ENSTAR requires the following regulatory approvals and grants of leases to begin the Project:

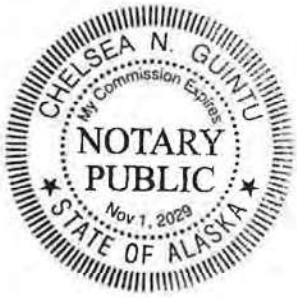
- RCA advance determination of prudence;
- AOGCC approval for storage injection;
- DNR – Oil and Gas Lease Amendment and Natural Gas Storage Lease;
- Alaska Mental Health Trust – Oil and Gas Lease Amendment and Natural Gas Storage Lease; and
- Cook Inlet Regional Incorporated – Oil and Gas Lease Amendment and Natural Gas Storage Lease.

26. Once the regulatory approvals and the leases have been granted, ENSTAR can begin utilizing the existing compressor for the injection of natural gas into one of the three existing wells within approximately two months, dependent on rig availability and progress on pipe procurement. Pipe procurement is expected to take approximately six months. Based on vendor input, ENSTAR will need six months to procure the pipe necessary to bring the Project in-service. If approvals are expedited, we could have the Project in-service by the fourth quarter of 2026. As described in the Affidavit of Mr. Sims, having the Project in-service by the fourth quarter of 2026 will allow it to begin accepting gas volumes ENSTAR would otherwise have to reject.

FURTHER AFFIANT SAYETH NOT.

Matthew S. Federle

SUBSCRIBED AND SWORN TO OR AFFIRMED before me, the undersigned notary, at Anchorage, Alaska, this 12th day of January, 2026, to which witness my hand and seal.



Notary Public, State of Alaska
My commission expires: November 1, 2029

MATTHEW FEDERLE

EXPERIENCE

2011-Present CINGSA, LLC Kenai, AK.

Gas Storage Plant Director

- Supervise Plant Supervisor, Operators and Technicians; responsible for planning work schedules, maintenance work, and plant improvements.
- Successfully completed $70M Gas Storage facility expansion project.
- Oversight of gas well operations including supervision of contract services employed for well work.
- Management of O&M and Capital budgets.
- Responsible for all operational regulatory compliance.

1996–2011 ANR Pipeline Eaton Rapids, MI.

Cross Functional Technician

Maintained Operation and Maintenance Budget.

- Operated and maintained Natural Gas Storage Field Automation, Communication, Measurement, Storage Wells, and Electrical equipment.
- Programed, troubleshoot, and operated Allen Bradley, Entronic PLC's, Intellution MMI, Bristol 3330, Daniel MON Chromatograph controller, and various other PLC controllers.
- Performed maintenance on three 2650 HP Superior Engines and Compressors, a 500 kW Waukesha Generator, and all auxiliary support equipment.
- Responsible for annual inspections with the MPSC, DOT, and MDEQ to ensure that all government requirements are being met.

1995–1996 Southeastern Public Service Authority Portsmouth, VA.

Power Plant Control Room Operator

- Responsible for the safe and efficient operation of a 60 MW Co-Generation Facility.
- Plant consists of four RDF/Coal Fired Boilers and three 20 MW Extracting/Condensing Turbine Generators. Emissions controlled by the use of Fabric Filter Bag Houses.
- Coordinated Steam and Power Loads with Norfolk Navel Shipyard.
- Monitored all areas of plant Operation utilizing Fisher Provox and Intellution MMI to ensure the accomplishment of plant production goals and that EPA standards were met.

- Assisted Maintenance Department on regular basis.

1989–1995 United States Navy

Boiler Technician

- Supervised ten personnel in operating and maintaining four 1200 psi fuel oil fired boilers and associated auxiliary equipment.
- Performed work on Boilers, Heat Exchangers, Pumps, Valves, and Pneumatic controls on both nuclear and conventional power plants while assigned to Repair 9 Division AD-38.
- Qualified Oil King and certified to test and treat Boilerwater/Feedwater.
- Coordinated import and underway fuel replenishment.
- On Scene leader for hazardous material/oil spill team

EDUCATION

134 Earned College Credits.

- Steam Propulsion Maintenance Supervisor (Enlisted Code 4505)
- Maintenance Management
- Boilerwater/Feedwater test and treatment
- 1200 psi Boiler Advanced Operator
- Trained and Qualified in Numerous DOT operator tasks.

AWARDS

- Navy Achievement Medal
- Southwest Asia Service Medal
- National Defense Medal
- Good Conduct Award

REFERENCES AND COPIES AVAILABLE AT YOUR REQUEST.

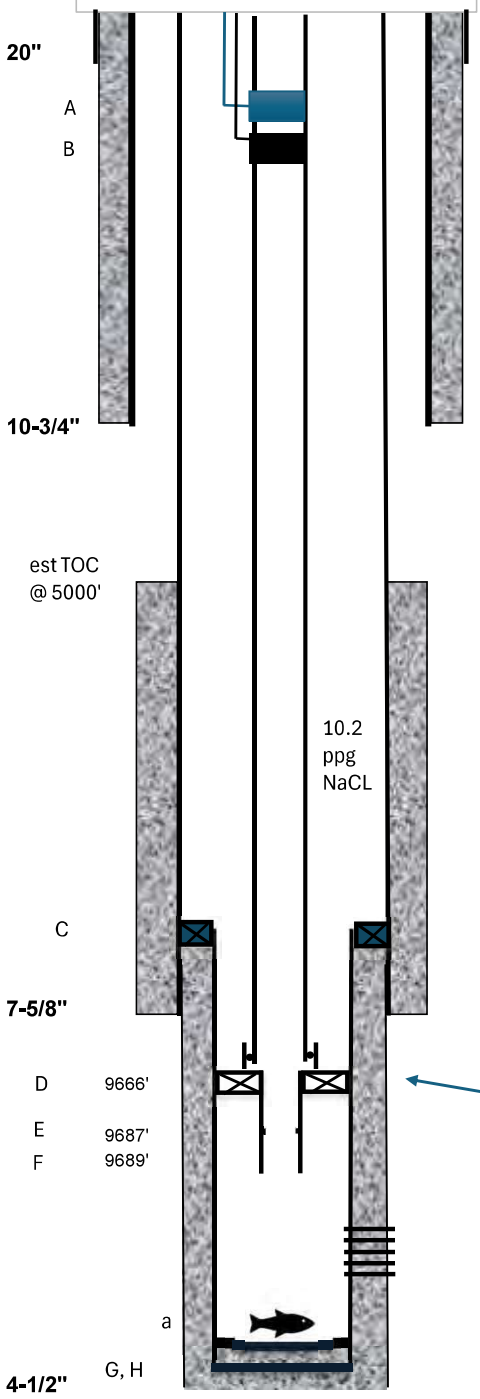
EESRVS@GMAIL.COM
324 W. ROCKWELL, SOLDOTNA, ALASKA 99669
907-280-8339

PTD: 211-043
API: 50-133-20595-00-00
Wellhead: FMC 10-3/4 x 7-5/8 x 2-7/8 5k Multibowl 235
Tree: FMC 2-9/16" 5k, SSV, CIM
GL: 134'
KB: 155'

Kenai Loop 1-1

Current Schematic

Spud: 4/15/2011
Last Completion: 5/30/2011



PBTD = 10585' MD / 10573' TVD
TD = 10,678' MD / 10,667' TVD

Casing / Tubing Detail

Size	Type	Wt	Grade, XN	ID	Top MD	Btm MD / TVD
16"	Conductor		N-80		0'	138' / 138'
10-3/4"	Surface	45.5#	L-80, BTC	9.950"	0'	3057' / 3055'
7-5/8"	Intermediate	29.7#	L-80, VAM	6.875"	0'	8024' / 8021'
4-1/2"	Liner	12.6#	L-80, TCII	6.276"	7892'	10676' / 10665'
2-7/8"	Tubing	6.5#	L-80, EUE	2.347"	0'	9666' / 9659'

Cement Detail

10-3/4"	564 bbls 12.0 ppg cement, 44 bbls **cmt to surface**, 4/29/11 EXPRO CBL
7-5/8"	126 bbls 13.5# lead, 52 bbls 15.8# tail, 5/19/11 EXPRO CBL (WBD note est at 5000') ***LOCATE***
4-1/2"	141 bbls 15.8 ppg, 1.18 yield Calss G, circulated cement off TOL, 5/19/11 EXPRO CBL ***LOCATE***

Jewelry Detail

Item	Description	ID	Depth, Top
A	2-7/8" Chemical Injection Mandrel, 0.25" CL(.049" wall)		454'
B	2-7/8" TR-SSSV, Baker TE-5, 0.25" CL(.049" wall)		536'
C	5-1/2" x 7-5/8" Baker ZXP Packer, FL 3 LH, 10' PBR, 5.750" ID		7892' MD, 7888' TVD
D	4-1/2" Baker Model D Packer w seal assembly, WL set		9666' MD 9659' TVD
E	1.875" XN nipple		9687'
F	Tubing tail, 2-3/8" cut off tubing		9689'
G	Landing Collar	NA	10951'
H	Float Shoe	NA	10676'

Fish Detail

Item	Description	Date	TOF
a	tubing tail with 2 bridge plugs cut off and dropped		10240' est

Perforation Detail

Sand	Top (MD)	Btm (MD)	Top (TVD)	Btm (TVD)	FT	Date
Tyonek	9705'	9725'	9698'	9717'	20'	5/23/2011
Tyonek	10008'	10049'	10000'	10040'	41'	5/23/2011

Wireline Set Permanant Packer (Millable)

Recent History

6/24/2015	1.75 GR to 10200'
6/25/2015	PT survey
5/3/2016	Set gauges in XN for PBU
9/3/2025	Well loaded and died, FL at 9269', WHP: 440 psi.
9/10/2025	Sundry submitted for CTU N2 lift, states well is loaded up and unable to flow.

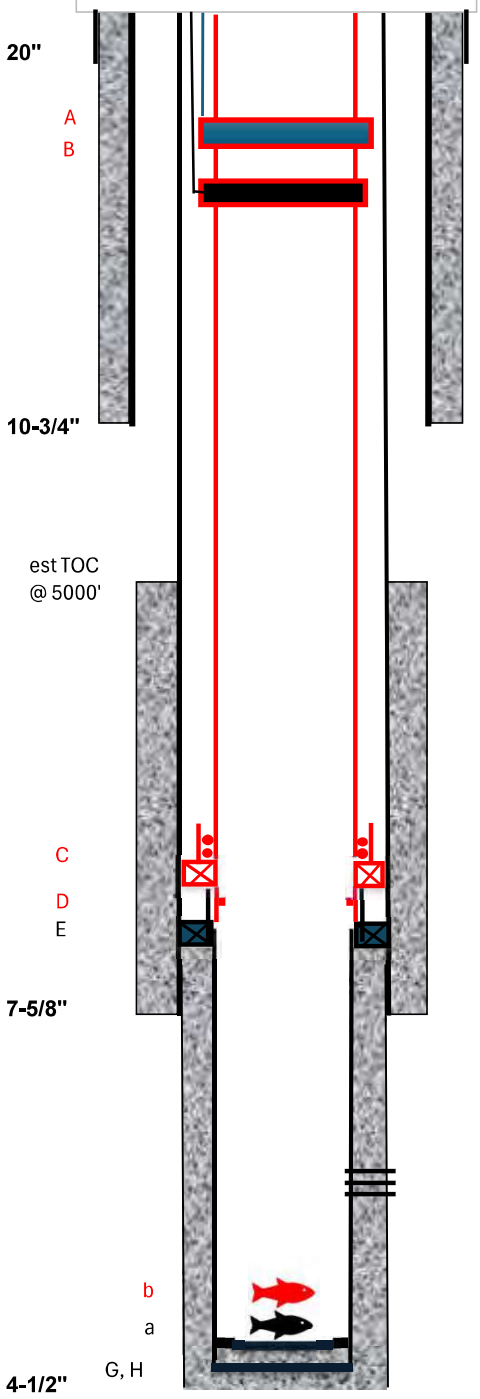
Last Rev: 11/6/2025
By: Jake Flora

PTD: 211-043
API: 50-133-20595-00-00
Wellhead: FMC 10-3/4 x 7-5/8 x 2-7/8 5k Multibowl 235
Tree: 4-1/2" 10k, SSV, CIM
GL: 134'
KB: 155'

Kenai Loop 1-1

Proposed Schematic

Spud: 4/15/2011
Last Completion: 5/30/2011



Casing / Tubing Detail

Size	Type	Wt	Grade, XN	ID	Top MD	Btm MD / TVD
16"	Conductor		N-80		0'	138' / 138'
10-3/4"	Surface	45.5#	L-80, BTC	9.950"	0'	3057' / 3055'
7-5/8"	Intermediate	29.7#	L-80, VAM	6.875"	0'	8024' / 8021'
4-1/2"	Liner	12.6#	L-80, TCII	6.276"	7892'	10676' / 10665'
4-1/2"	Tubing	12.6#	L-80, TBD	2.347"	0'	~7850'

Cement Detail

10-3/4"	564 bbls 12.0 ppg cement, 44 bbls **cmt to surface**, 4/29/11 EXPRO CBL
7-5/8"	126 bbls 13.5# lead, 52 bbls 15.8# tail, 5/19/11 EXPRO CBL (est at 5000')
4-1/2"	141 bbls 15.8 ppg, 1.18 yield Calss G, circulated cement off TOL, 5/19/11 EXPRO CBL

Jewelry Detail

Item	Description	ID	Depth, Top
A	4-1/2" Baker TR-SSSV		~500'
B	4-1/2" Chemical Injection Mandrel		~1200'
C	5-1/2" x 7-5/8" Baker ZXP Packer w 10' PBR / seal assembly		~7850'
D	4-1/2" XN nipple (for future reservoir isolation if necessary)		~7870'
E	5-1/2" x 7-5/8" Baker ZXP Packer, FlexLock III LH		7892' MD, 7888' TVD
F	Tubing tail, 2-3/8" cut off tubing		9689'
G	Landing Collar	NA	10951'
H	Float Shoe	NA	10676'

Fish Detail

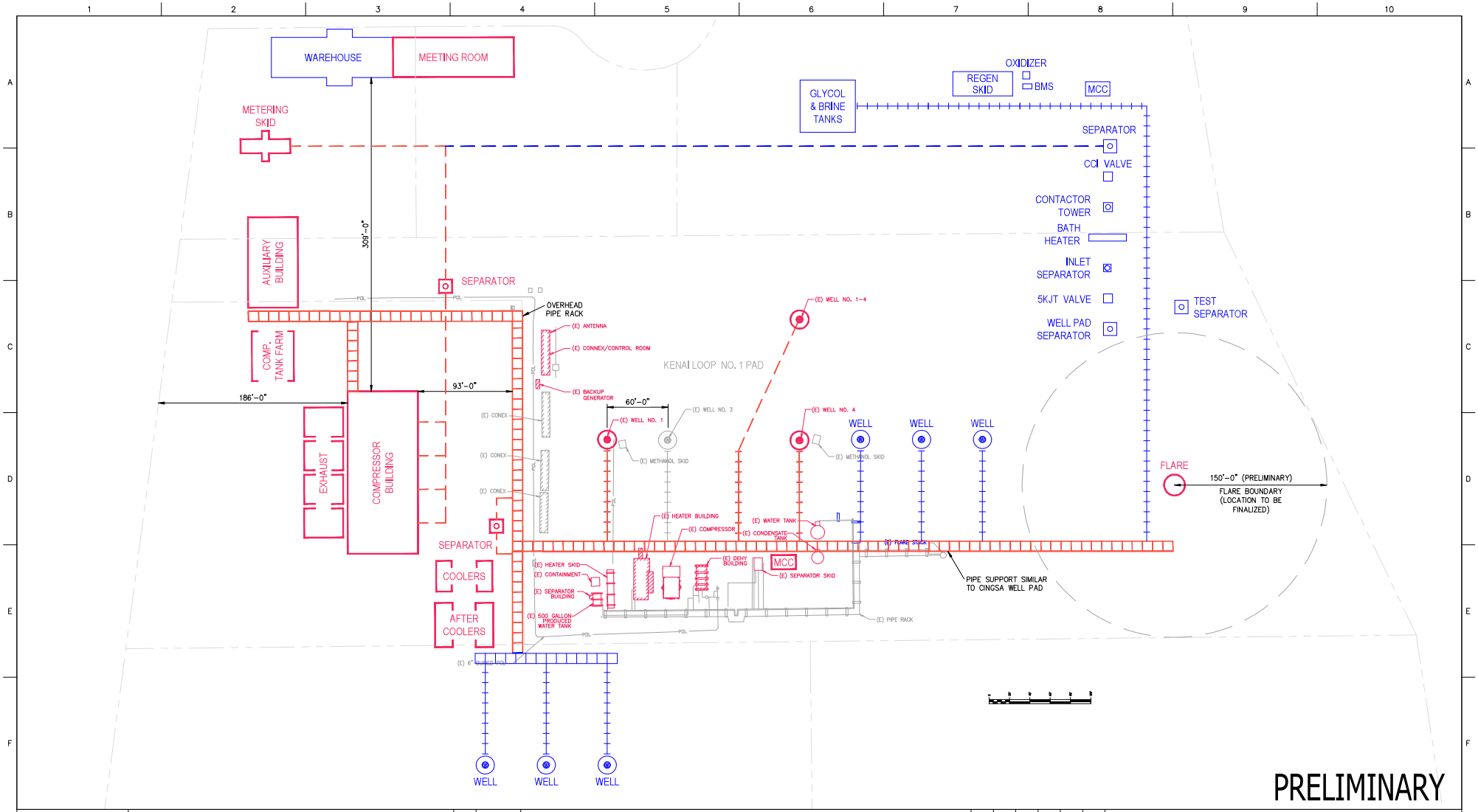
Item	Description	Date	TOF
a	tubing tail with 2 bridge plugs cut off and dropped		10240' est
b	4-1/2" WFD Ultra Pak packer & tailpipe 23' OAL		~10210'

Perforation Detail

Sand	Top (MD)	Btm (MD)	Top (TVD)	Btm (TVD)	FT	Date
Tyonek	9705'	9725'	9698'	9717'	20'	5/23/2011
Tyonek	10008'	10049'	10000'	10040'	41'	5/23/2011

PBTD = 10585' MD / 10573' TVD
TD = 10,678' MD / 10,667' TVD

Last Rev: 1/9/2026
By: Jake Flora



PRELIMINARY

DWG. NO.	TITLE	NO.	DATE	DESCRIPTION	DWN.	CHK'D	D. ENG	P. ENG	P. MGR	CLIENT
REFERENCE DRAWINGS		XX	XXX	XXX	XXX	XXX	XXX	XXX	XXX	XXX
		ISSUES / REVISIONS			ENGINEERING APPROVALS					

ASRC Consulting & Environmental
a subsidiary of ASRC Energy Services

TITLE
SITE PLAN
WELL PAD & FACILITIES PHASES 1A AND 1B
HELIX NATURAL GAS STORAGE ALASKA

DRAWN BY:	CHECKED BY:	DISCIPLINE ENG.	PROJ. ENG.	PROJ. MGR.	REV.
XXX	XXX	-	XXX	XXX	XX

JOB#	DATE	SCALE	DWG. NO.
XXX	XXX	NONE	CINGSA ACES HELIX SITE PLAN PH 1A 1B 12-18-25

Docket U-26-____

Exhibit MSF-3
Page 1 of 1

Update to TransCanada 2009 Gas Storage Prospectivity Study Kenai, Alaska

December 2025

Prepared for

ENSTAR Natural Gas Company
3000 Spenard Road
Anchorage, AK 99503-3606

Prepared by

3900 C Street, Suite 700
Anchorage, Alaska 99503

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Table of Contents

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List of Tables and Figures

TABLES

FIGURES

Acronyms and Abbreviations

AIX	AIX Energy LLC
AOGCC	Alaska Oil and Gas Conservation Commission
ASRC Energy	ASRC Energy Services
bbl	barrel(s)
bcf	billion cubic feet
CINGSA	Cook Inlet Natural Gas Storage Alaska
CLU	Cannery Loop Unit
ENSTAR	ENSTAR Natural Gas Company
GWC	gas-water contact
Hilcorp	Hilcorp Alaska LLC
LLC	Limited Liability Company
Mcf	thousand cubic feet
MMcf	million cubic feet
N/A	not applicable
PR	producing reservoir
SCU	Soldotna Creek Unit
SI	shut-in
SR_34-10	Swanson River Pad 34-10
SR_Center	Swanson River Central Pad
SR_SCU	Swanson River – Soldotna Creek Unit
TransCanada	TransCanada Corporation

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1.0 BACKGROUND AND PURPOSE

1.1 2009 TransCanada Gas Storage Assessment

In 2009, at the request of ENSTAR Natural Gas Company (ENSTAR), TransCanada Corporation (TransCanada) completed a basin-wide assessment of gas storage prospectivity within the Cook Inlet Basin. The study, conducted by TransCanada geoscientist Blaine Campbell within TransCanada's Reservoir Services Department, evaluated publicly available geologic and reservoir data to identify gas pools suitable for potential third-party gas storage development. The work was undertaken in response to ENSTAR's solicitation of interest for independent gas storage facilities to support regional energy reliability.

The 2009 TransCanada assessment provides an important technical baseline for understanding Cook Inlet gas pool characteristics, historical production performance, and initial screening considerations relevant to gas storage feasibility. However, the study reflects data availability, ownership conditions, and operational assumptions current as of 2009, many of which have changed materially over the intervening period.

1.2 Summary of 2009 Screening Results

The TransCanada assessment screened 48 known gas pools across the Cook Inlet Basin using a phased evaluation approach. Phase 1 screening, completed on May 8, 2009, reduced the initial pool set to 11 candidates warranting further technical review. Phase 2 screening, completed on May 22, 2009, further refined the list to seven pools considered most prospective for gas storage development.

For clarity, the phased evaluation approach consisted of sequential screening steps intended to narrow the pool of candidates based on publicly available information, rather than to perform detailed reservoir performance or storage feasibility analyses. Specifically, the phased evaluation was used to:

- Identify gas pools with sufficient historical production and data availability.
- Screen out reservoirs with apparent geologic, operational, or ownership constraints.
- Prioritize candidates for potential future, project-specific technical evaluation.

The study concluded with a final summary memorandum dated June 10, 2009, which ranked nine candidate gas storage pools and recommended three priority reservoirs for additional investigation:

- Beaver Creek Sterling

- Cannery Loop Sterling (now developed as the Cook Inlet Natural Gas Storage Alaska [CINGSA] facility)
- Kenai Gas Field Sterling 5.2 reservoir

Because the 2009 materials include multiple screening stages and a subsequent ranking memorandum, pool counts vary by phase and document; this report uses the Phase 2 shortlist, additional Phase 1 passers, and the Phase 3 ranked pools to present a consolidated, planning-level inventory.

1.3 Purpose and Scope of the 2025 Update

In July 2025, ENSTAR requested ASRC Energy Services (ASRC Energy) to review and update the findings of the 2009 TransCanada study to reflect current field ownership, development status, and relevance to present-day gas storage considerations. This effort is intended as a contextual update rather than a reanalysis of the original TransCanada technical work.

This update focuses on ownership status, pool and field activity, and continued relevance to gas storage development; it does not reevaluate subsurface reservoir performance or storage design parameters.

The 2009 Phase 2 (Second Pass) memoranda include reservoir property estimates (e.g., porosity, permeability, net pay, pressure), inferred drive mechanisms, conceptual deliverability and storage development scenarios, and order-of-magnitude cost considerations; however, those engineering- and reservoir-level evaluations are not updated, validated, or reinterpreted as part of this 2025 status review.

The initial ASRC Energy review was completed on July 31, 2025, based on the Phase 1 and Phase 2 TransCanada memoranda prepared in 2009. The final TransCanada summary memorandum dated June 10, 2009, which ranked nine candidate gas storage pools, was not made available to ASRC Energy until after completion of the initial review. Upon receipt, and given its relevance to historical screening context, this final summary was incorporated into the present update issued December 21, 2025.

1.4 Report Organization

This report is organized to provide a clear progression from historical screening context to a current, field-by-field evaluation of gas pools previously identified as prospective for underground gas storage.

Sections 2.0 through 15.0 present individual field and gas pool evaluations. Each section follows a consistent structure to support comparison across fields and includes:

- A brief summary of the pool's relevance within the 2009 TransCanada gas storage screening.
- Current ownership and operational context.
- A discussion of present production status, shut-in conditions, or storage use based on publicly available data.
- A summary table documenting the status of wells completed in the evaluated pool.
- A 2025 update describing how current development, ownership, or operational use affects availability for potential gas storage development.

This standardized approach allows historical screening results to be considered alongside present-day operational conditions while avoiding reinterpretation of the original TransCanada technical analyses.

Section 1.5 summarizes the comparative screening results in tabular form, integrating historical screening outcomes with current ownership and development status. Section 1.6 presents overall conclusions regarding the availability of Cook Inlet gas pools for potential gas storage development based on the 2025 review.

1.4.1 Original Source Documents

The 2009 TransCanada gas storage prospectivity assessment was documented in a series of internal memoranda prepared by Blaine Campbell for TransCanada Corporation in response to ENSTAR Natural Gas Company's solicitation of interest for third-party gas storage development. These memoranda document the original screening of Cook Inlet gas pools based on publicly available data and are referenced in this report solely to provide historical context and source attribution.

The original TransCanada screening was documented in three sequential memoranda:

- **Phase 1 (First Pass) Pool Screening –** Preliminary basin-wide screening of 48 Cook Inlet gas pools using publicly available geologic and production data to identify candidates warranting further review (Campbell 2009a).
- **Phase 2 (Second Pass) Pool Screening –** Refined technical screening of pools identified in Phase 1, incorporating additional reservoir characteristics, well information, and operational considerations to further narrow prospective gas storage candidates (Campbell 2009b).
- **Phase 3 (Final Summary and Ranking) –** Synthesis and ranking of screened gas pools, with recommendations for priority reservoirs for potential further investigation in response to ENSTAR's solicitation of interest (Campbell 2009c).

These memoranda are cited to establish the historical screening framework against which current ownership and development conditions are evaluated. They are not reproduced in full, and this report does not adopt, replicate, or update the original TransCanada technical analyses. All

interpretations, synthesis, and conclusions presented herein reflect the independent evaluation performed by ASRC Energy using current (2025) information.

1.4.2 Use of Phase 2 (Second Pass) Screening Results

This review references the Phase 2 (Second Pass) gas storage prospectivity assessment as the most technically detailed stage of the original screening effort. Phase 2 incorporated results from the initial Phase 1 screening and applied additional technical criteria to refine the list of prospective gas storage candidates.

Phase 1 results served as a preliminary, high-level screening tool and are not repeated here. The final summary memorandum (Phase 3) synthesized Phase 2 results and provided rankings but did not introduce new technical screening criteria beyond those documented in Phase 2.

For purposes of this update – specifically, evaluating current ownership, development status, and operational relevance – the Phase 2 analysis is used solely as historical screening context and does not constitute the analytical framework for this report.

Accordingly, this report presents an independent, field-by-field evaluation that incorporates updated information on ownership, development status, and operational use, while referencing the Phase 2 screening results where helpful for historical context.

1.4.3 Use of Original Source Material and 2025 Updates

This report references the Phase 2 (Second Pass) gas storage prospectivity review prepared by Blaine Campbell for TransCanada in 2009 (Campbell 2009b) as an original source document providing historical screening context. Selected screening conclusions and figures from the 2009 memoranda are cited as originally presented, without reinterpretation or modification, and are used for reference purposes only.

This report does not reproduce original TransCanada text or figures in full. Instead, it presents an independent, field-by-field evaluation prepared by ASRC Energy that integrates historical screening outcomes with current (2025) ownership, development status, and operational context. All narrative text, interpretive discussion, and conclusions presented herein reflect ASRC Energy's synthesis of original source material and current information.

The Phase 2 (Second Pass) memorandum documented several screening principles that guided pool selection and discussion, including an emphasis on Sterling Formation sands as the primary interval of interest for potential gas storage and the consideration of Beluga and Upper Tyonek reservoirs in select fields where characteristics and available data supported further review (Campbell 2009b). The memorandum also noted that prospects were generally preferred on the Kenai Peninsula side of Cook Inlet, given limited infrastructure and comparatively higher development and operating costs

on the west side of the basin and offshore (Campbell 2009b). These considerations are cited here solely to describe the original screening framework and are not updated or reevaluated as part of this 2025 status review.

The 2009 Phase 2 screening memoranda prepared by Campbell (2009b) use pool names and groupings that reflect how production and reservoir information was summarized in publicly available data at the time of evaluation (e.g., "Sterling undefined gas"). In this update, pool and interval descriptions are aligned with current publicly reported well completion and production records, which in some cases group wells across multiple intervals (e.g., Sterling and Upper Beluga) under a single reporting designation. Where terminology differs from the original 2009 memoranda, the intent is to improve consistency with current data reporting rather than to reinterpret reservoir stratigraphy, screening conclusions, or rankings presented by Campbell (2009a–c).

1.5 Summary of Evaluation Results

Table 1-1 summarizes Cook Inlet gas pools evaluated for potential gas storage based on the 2009 TransCanada screening results and current (2025) ownership and development status. The table presents historical screening outcomes from the Phase 1 and Phase 2 evaluations and final rankings reported in 2009, alongside present-day ownership, pool status, and field status.

Phase 1 and Phase 2 "Pass" indicators reflect whether a pool advanced through successive screening stages based on available public data at the time of evaluation. The "2009 Final Rank" column reflects rankings assigned in the TransCanada final summary memorandum where applicable; pools without a final rank are shown for completeness based on screening history or subsequent inclusion.

The Phase 3 (final) memorandum provided rankings and qualitative commentary that, in some cases, did not align cleanly with Phase 2 prospective or non-prospective labels. These differences reflect evolving interpretation, additional context, and narrative discussion rather than a formal re-screening using consistent criteria.

Accordingly, the Phase 1 and Phase 2 indicators and Phase 3 rankings are presented as documented in the original 2009 materials and should be interpreted as screening-stage outcomes rather than definitive or internally uniform classifications.

The 2025 ownership and status columns are provided for comparative planning purposes only and do not represent updated technical screening, ranking, or feasibility determinations.

1.6 Conclusion

The 2025 review indicates that few opportunities remain to acquire depleted gas reservoirs suitable for gas storage development outside of fields currently owned and actively developed by Hilcorp

Alaska LLC (Hilcorp). Of the pools identified as prospective candidates in the 2009 TransCanada study, nearly all have since been incorporated into ongoing production or development programs, or in one case converted to an active gas storage facility.

The Kenai Loop Upper Tyonek gas pool, which was not included in the original 2009 screening due to the timing of drilling activity, remains the only identified candidate that is not under Hilcorp ownership and warrants further investigation for potential gas storage application. Any such investigation would require site-specific technical and commercial evaluation beyond the scope of this report.

Table 1-1 Evaluation of Cook Inlet Gas Storage Candidates

Field	Pool	2009 Owner	2009 Phase 1 Pass	2009 Phase 2 Pass	2009 Final Rank	2025 Owner	2025 Pool Status	2025 Field Status	Notes
Beaver Creek	Sterling Gas	Marathon	Y	Y	1	Hilcorp	SI	PR	Field in active development
Cannery Loop	Sterling Undefined	Marathon	Y	Y	2	CINGSA	Active Gas Storage	Active Gas Storage	Converted to CINGSA
Kenai	Sterling 5.2	Marathon	Y	Y	3	Hilcorp	PR	PR	Field in active development
Swanson River	Sterling Undefined	Chevron	Y	N	4	Hilcorp	PR	PR	Field in active development
Swanson River	Tyonek Undefined	Chevron	N	N	5	Hilcorp	PR	PR	Field in active development
Ivan River	Tyonek (Undefined Gas)	Chevron	Y	N	6	Hilcorp	Plugged	PR (Sterling)	Field in active development
Cannery Loop	Upper Tyonek	Marathon	Y	N	7	Hilcorp	SI	PR	Field in active development
Cannery Loop	Beluga	Marathon	Y	N	8	Hilcorp	PR	PR	Field in active development
Beaver Creek	Beluga	Marathon	N	N	9	Hilcorp	PR	PR	Field in active development
Kenai Loop	Upper Tyonek	AIX	N/A	N/A	–	AIX	PR	PR	Under review
Kenai	Sterling 3	Marathon	Y	Y	–	Hilcorp	PR	PR	Field in active development
Kenai	Sterling 5.1	Marathon	Y	Y	–	Hilcorp	SI	PR	Field in active development
Kenai	Upper Tyonek	Marathon	Y	Y	–	Hilcorp	PR	PR	Field in active development

Field	Pool	2009 Owner	2009 Phase 1 Pass	2009 Phase 2 Pass	2009 Final Rank	2025 Owner	2025 Pool Status	2025 Field Status	Notes
Sterling	Sterling Undefined	Marathon	Y	N	–	Hilcorp	SI	SI	GWC present; 2025 drilling permits

Notes:

1. Phase 1, Phase 2, and Final Rank results reflect historical screening outcomes reported in 2009 and are included for reference only.
2. Pools shown with " – " in the 2009 Final Rank column were either not assigned a final ranking in the TransCanada final summary memorandum or were included in this review based on subsequent exploration or development activity.
3. Ownership and pool/field status information reflects conditions current as of 2025.
4. References to gas–water contact (GWC) are based on historical information reported in original source documents and are included for contextual purposes only.
5. Inclusion of a pool or field in this table does not constitute a determination of technical feasibility, availability, or suitability for gas storage development.

Key:

CINGSA = Cook Inlet Natural Gas Storage Alaska

GWC = gas–water contact

N/A = not applicable

Plugged = pool abandoned or plugged

PR = producing reservoir

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025; historical screening results and rankings are from the TransCanada gas storage prospectivity memoranda (Campbell 2009a–c).

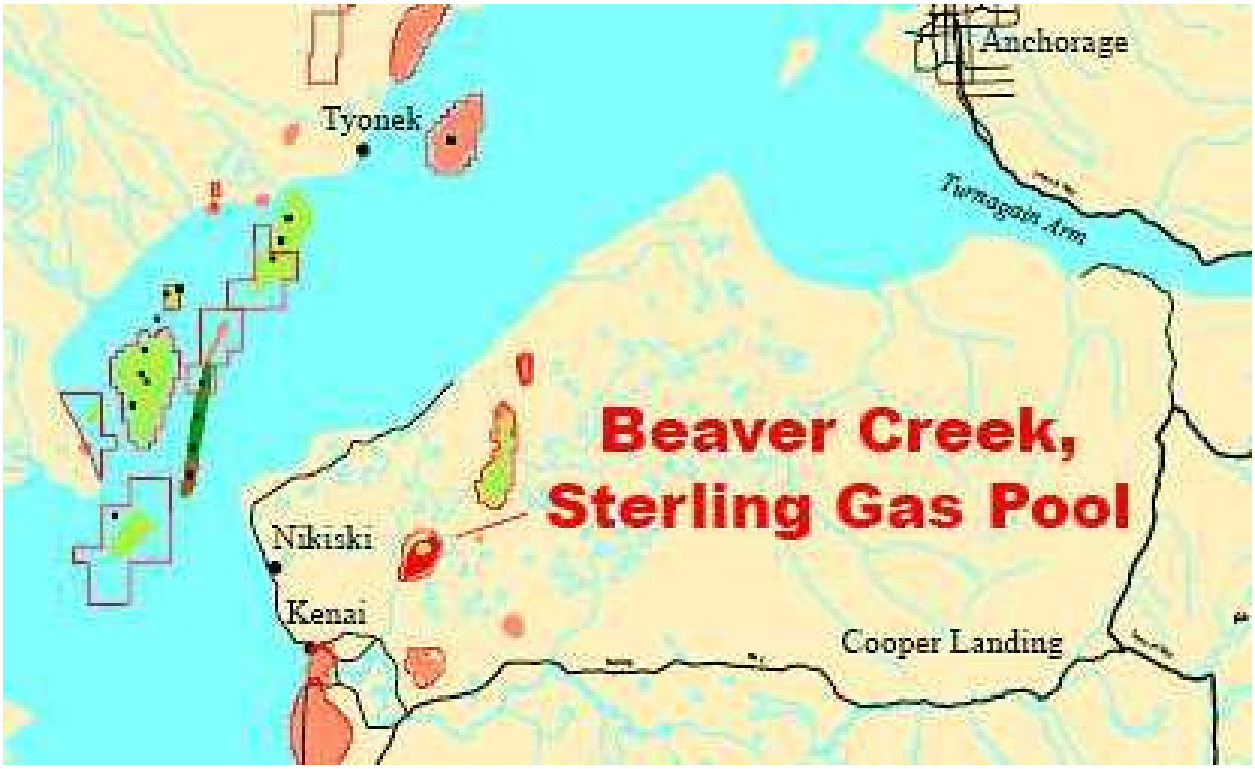
2.0 BEAVER CREEK FIELD, STERLING GAS POOL (STERLING FORMATION)

2.1 2009 Screening Context

The Beaver Creek Field produces from the Sterling Formation and was identified in the 2009 TransCanada gas storage screening as a high-ranking candidate based on historical production performance and reservoir characteristics. At the time of the original screening, the Beaver Creek Sterling gas pool ranked first among evaluated candidates and was considered prospective for potential underground gas storage development.

Figure 2-1 shows the location and areal extent of the Beaver Creek Field, Sterling gas pool, as depicted in the Phase 2 TransCanada screening.

Figure 2-1 Beaver Creek Field – Sterling Gas Pool (Sterling Formation)



Note: Location and areal extent of the Sterling gas pool at Beaver Creek Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

2.2 Ownership and Operations

Ownership of the Beaver Creek Field has changed since completion of the 2009 screening. The field is currently owned and operated by Hilcorp Alaska LLC (Hilcorp), which acquired the former Marathon Cook Inlet assets in 2012. Since that time, Hilcorp has remained an active operator in the field and continues to pursue development activities, including drilling and sidetracking of wells within the Beaver Creek Unit.

2.3 Current Production Status

As of 2025, the Beaver Creek Field is classified as producing at the field level; however, production from the Sterling gas pool is currently shut in. June 2025 production records indicate no reported gas production from the Sterling pool, despite the presence of multiple completed wells. Available data indicate that three Sterling gas wells are completed in the field and currently shut in.

2.4 Well Production Summary

Table 2-1 summarizes the current production status of wells completed in the Beaver Creek Field Sterling gas pool based on available June 2025 production data. The table is provided to document well status and recent production activity and to support evaluation of the field's current operational status relative to its historical screening for gas storage potential.

2.5 2025 Update

The Beaver Creek Field remains under active development by Hilcorp, and continued drilling and sidetrack activity indicates that the field is being managed as an ongoing production asset rather than as a candidate for depletion-based gas storage conversion. While the Sterling gas pool retains characteristics that supported its high ranking in the 2009 screening, current ownership and operational use limit its availability for third-party gas storage development. Total production for the pool is over 130 BCF of gas and 1.8 MM bbls of water.

Table 2-1 Beaver Creek Field – Sterling Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Beaver Creek Unit 07a	Hilcorp Alaska, LLC	Gas well, single completion	Beaver Creek	Sterling Undefined Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Beaver Creek Unit 10	Hilcorp Alaska, LLC	Gas well, single completion	Beaver Creek	Sterling Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Beaver Creek Unit 25	Hilcorp Alaska, LLC	Gas well, single completion	Beaver Creek	Sterling Gas	6/2025	Gas Production	Shut-In	0	0	0	0

Notes:

1. Production data reflect reported June 2025 volumes. All wells listed were shut in during the reporting period; zero production does not indicate abandonment or reservoir depletion. Table data are provided to document current operational status and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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3.0 CANNERY LOOP UNIT, STERLING UNDEFINED GAS POOL (STERLING FORMATION)

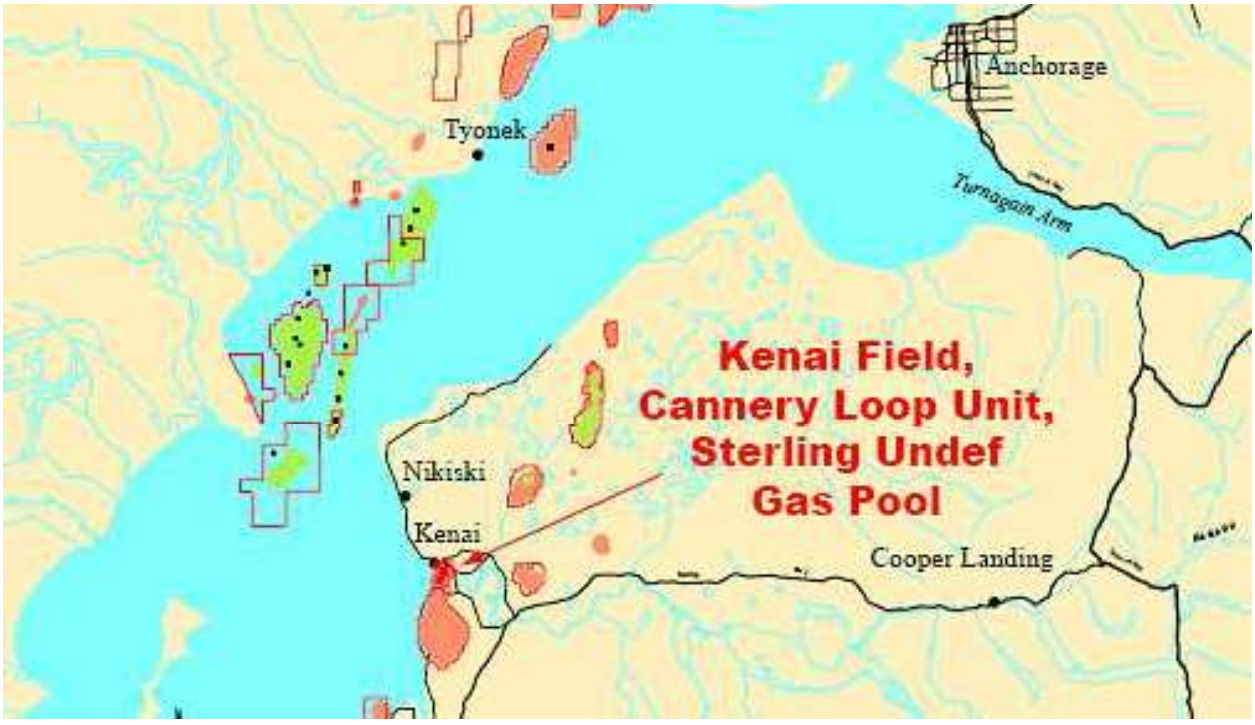
3.1 2009 Screening Context

The Cannery Loop Unit (CLU) Sterling gas pool was evaluated as part of the 2009 TransCanada gas storage screening and ranked among the highest-priority candidates for potential underground gas storage development. At the time of the original screening, the Sterling pool at Cannery Loop was identified as prospective based on reservoir characteristics, historical production performance, and its suitability for storage conversion.

Subsequent to the 2009 screening, a portion of the Cannery Loop Sterling reservoir was developed as the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility, representing the only large-scale underground gas storage project constructed in the Cook Inlet Basin to date.

Figure 3-1 shows the location and areal extent of the Cannery Loop Unit Sterling undefined gas pool as depicted in the Phase 2 TransCanada screening.

Figure 3-1 Cannery Loop Unit – Sterling Undefined Gas Pool (Sterling Formation)



Note: Location and areal extent of the Sterling undefined gas pool at the Cannery Loop Unit as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b).

3.2 Ownership and Operations

Ownership and operational control of the Cannery Loop Unit have changed since completion of the 2009 TransCanada study. Marathon Oil Company originally held interests in the Cannery Loop Sterling pool prior to development of the CINGSA facility. Hilcorp Alaska LLC (Hilcorp) acquired the Marathon Cook Inlet assets in 2012 and is currently the operator of the Cannery Loop Unit.

Hilcorp continues to manage active production assets within the Cannery Loop Unit outside of the CINGSA storage interval, including wells completed in overlying Sterling sands.

3.3 Current Production Status

As of 2025, the Cannery Loop Unit is classified as producing; however, the Sterling undefined gas pool addressed in this section is currently shut in. June 2025 production records indicate no reported gas production from the Sterling pool. Available data indicate that one Sterling gas well completion remains within the Cannery Loop Unit and is currently shut in.

3.4 Well Production Summary

Table 3-1 summarizes the current production status of the Sterling gas well completed within the Cannery Loop Unit based on available June 2025 production data. The table is provided to document well status and recent production activity and to distinguish producing and shut-in Sterling completions from the underlying CINGSA storage interval.

3.5 2025 Update

The Cannery Loop Unit remains under active development and management by Hilcorp. While the Sterling C reservoir has been converted to active gas storage operations at the CINGSA facility, limited Sterling gas production capability persists in overlying sands within the unit as evidenced by only 117 MCF being reported to the AOGCC from Sterling formations outside of the Sterling C. As of 2025, the identified Sterling completion above the CINGSA interval is shut in and not contributing to field production.

Any remaining Sterling gas pools within the Cannery Loop Unit are being managed as part of ongoing field operations rather than as candidates for new storage conversion.

Table 3-1 Cannery Loop Unit – Sterling Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Kenai Loop Unit 06RD	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Sterling Undefined Gas	6/2025	Gas Production	Shut-In	0	0	0	0

Notes:

1. Production data reflect reported June 2025 volumes. The well listed was shut in during the reporting period; zero production does not indicate abandonment or loss of reservoir capability. Table data are provided to document current operational status and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

CLU Cannery Loop Unit

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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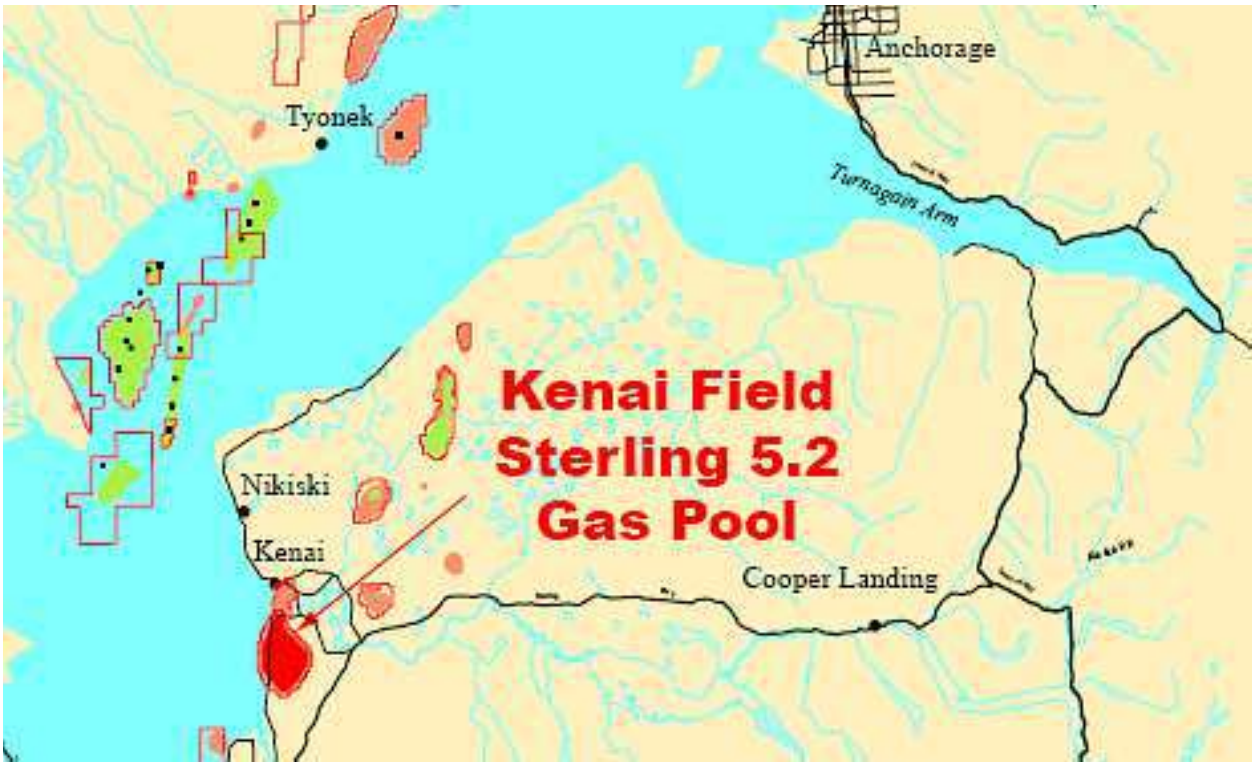
4.0 KENAI FIELD, STERLING 5.2 GAS POOL (STERLING FORMATION)

4.1 2009 Screening Context

The Sterling 5.2 gas pool in the Kenai Field was evaluated as part of the 2009 TransCanada gas storage screening and was identified as one of the top-ranked candidates for potential underground gas storage development. At the time of the screening, the Sterling 5.2 reservoir ranked third overall among evaluated Cook Inlet gas pools and was considered prospective based on its production history, reservoir characteristics, and infrastructure setting.

Figure 4-1 shows the location and areal extent of the Kenai Field Sterling 5.2 gas pool as depicted in the Phase 2 TransCanada screening.

Figure 4-1 Kenai Field – Sterling 5.2 Gas Pool (Sterling Formation)



Note: Location and areal extent of the Sterling 5.2 gas pool at the Kenai Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

4.2 Ownership and Operations

Ownership of the Kenai Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the operator of the Kenai Field. Since acquisition, Hilcorp has continued active development and management of the field across multiple producing intervals.

4.3 Current Production Status

As of 2025, the Kenai Field is classified as producing. Production from the Sterling 5.2 gas pool remains active, although the majority of completed wells in the pool are currently shut in. June 2025 production data indicate that one Sterling 5.2 gas well was flowing during the reporting period, while six additional completed wells were shut in. Reported gas production from the Sterling 5.2 pool totaled approximately 11 MMcf for June 2025.

4.4 Well Production Summary

Table 4-1 summarizes the current production status of wells completed in the Kenai Field Sterling 5.2 gas pool based on available June 2025 production data. The table documents individual well status, production method, and reported production volumes and is provided to support evaluation of current operational conditions relative to the pool's historical screening for gas storage potential.

4.5 2025 Update

The Kenai Field remains under active development by Hilcorp. While the Sterling 5.2 gas pool continues to be managed as a producing reservoir, operational focus within the field reflects ongoing production and storage activities across multiple pools. Hilcorp utilizes an underlying reservoir interval (commonly referred to as Pool 6) within the Kenai Field for gas storage operations.

The continued production and integrated field management strategy limit the availability of the Sterling 5.2 gas pool for third-party gas storage development, notwithstanding its favorable ranking in the 2009 TransCanada screening. To date approximately 50.1 BCF of gas and 1,081,886 bbls of water have been produced from the Sterling 5.2 gas pool.

Table 4-1 Kenai Field – Sterling 5.2 Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Kenai Beluga Unit 22-06	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Beluga Unit 33-06	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Beluga Unit 23-7	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Beluga Unit 14-67	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Beluga Unit 43-07X	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Beluga Unit 41-6	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Deep Unit 10	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.2 Gas	6/2025	Gas Production	Flowing	0	10,976	19	30

Notes:

1. Production data reflect reported June 2025 volumes.
2. Most wells completed in the Sterling 5.2 gas pool were shut in during the reporting period; one well (Kenai Deep Unit 10) was flowing and accounted for all reported gas production.
3. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key: bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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5.0 SWANSON RIVER FIELD, STERLING AND UPPER BELUGA GAS POOLS (STERLING AND BELUGA FORMATIONS)

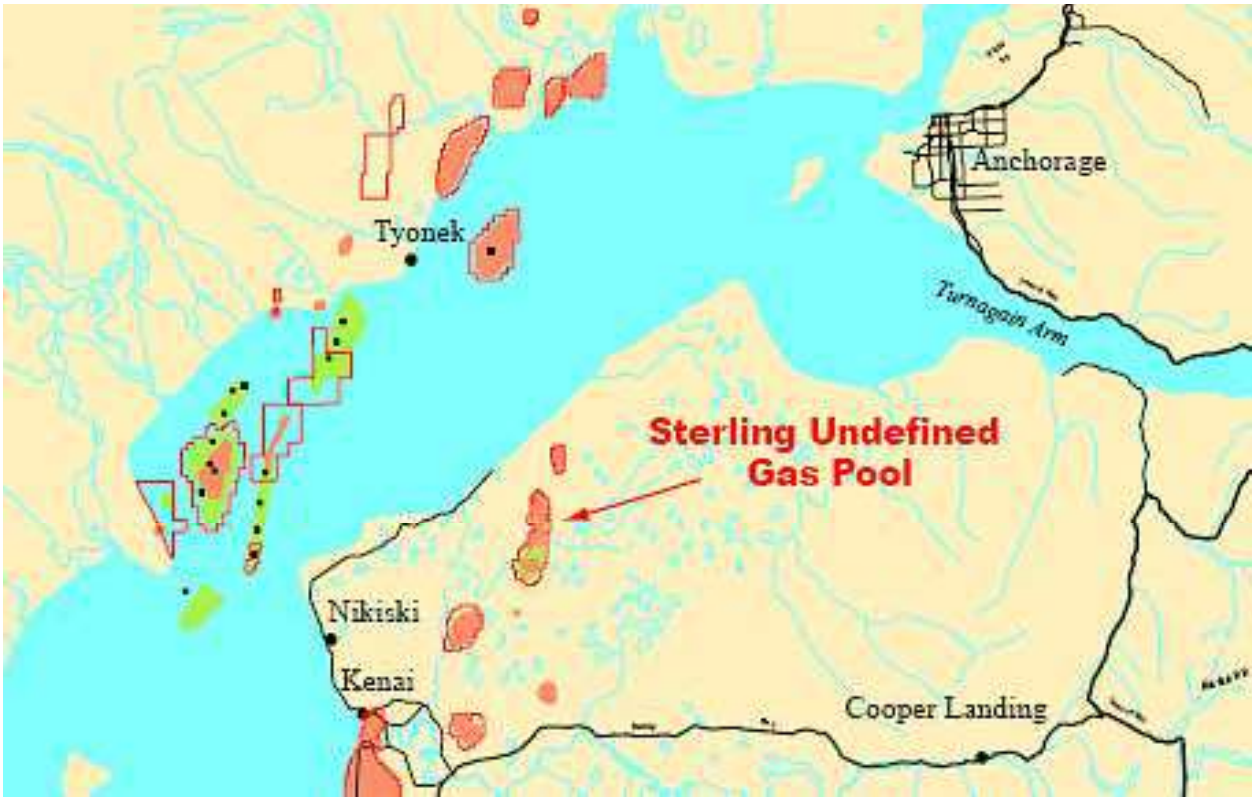
5.1 2009 Screening Context

The Swanson River Field was evaluated as part of the 2009 TransCanada gas storage screening, including assessment of gas-bearing intervals within the Sterling Formation. At the time of the screening, Sterling and Upper Beluga gas pools at Swanson River were reviewed as part of a broader evaluation of mature Cook Inlet fields with established production history and extensive infrastructure.

While the Sterling and Upper Beluga gas pools at Swanson River did not rank among the highest-priority candidates in the final 2009 screening results, the field was recognized as a long-producing asset with multiple stacked reservoirs and operational flexibility relevant to gas storage considerations.

Figure 5-1 shows the location and areal extent of the Sterling and Upper Beluga gas pools at the Swanson River Field as depicted in the Phase 2 TransCanada screening.

Figure 5-1 Swanson River Field – Sterling and Upper Beluga Gas Pools (Sterling and Beluga Formations)



Note: Location and areal extent of the Sterling and Upper Beluga gas pools at the Swanson River Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

5.2 Ownership and Operations

Ownership of the Swanson River Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Chevron Cook Inlet assets, including the Swanson River Field, in 2011 and is currently the operator. Since acquisition, Hilcorp has continued active development and management of the field across multiple producing intervals.

The Swanson River Field remains one of the most operationally complex fields in Cook Inlet, supporting oil production, gas production, and gas storage operations in different stratigraphic intervals.

5.3 Current Production Status

As of 2025, the Swanson River Field is classified as producing. Production from the Sterling and Upper Beluga gas pools remains active, with a combination of flowing and shut-in wells. June 2025 production records indicate that three gas wells completed in Sterling and Upper Beluga intervals were flowing during the reporting period, while five additional wells were shut in. Reported gas production from these intervals totaled approximately 71 MMcf for June 2025.

One well completed in the Hemlock interval from a pool reported as Sterling-associated oil production is currently shut in and is included in the well inventory for completeness.

5.4 Well Production Summary

Table 5-1 summarizes the current production status of wells completed in the Swanson River Field Sterling and Upper Beluga gas pools, based on available June 2025 production data. The table documents individual well status and reported production volumes to support evaluation of current operations relative to historical screening considerations.

5.5 2025 Update

The Swanson River Field remains under active development by Hilcorp and continues to be managed as a producing asset. While Sterling and Upper Beluga gas pools remain in active use, the continued production role of these intervals limits their availability for third-party gas storage development.

Existing gas storage operations at Swanson River are focused on deeper Tyonek Formation intervals and do not currently involve Sterling or Upper Beluga Formation gas pools.

Table 5-1 Swanson River Field – Sterling and Upper Beluga Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Swanson River Unit 231-33	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Flowing	0	44,732	71,896	23
Swanson River Unit 222-33	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Flowing	0	16,363	1,106	23
Swanson River Unit 212-27	Hilcorp Alaska, LLC	Oil well, single completion	Swanson River	Hemlock From Sterling Undefined Oil	6/2025	Oil Production	Shut-In	0	0	0	0
Swanson River Unit 218-15	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Swanson River Unit 230-35	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Flowing	0	10,024	49,797	30
Swanson River Unit 213-15	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Swanson River Unit 224-16	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Swanson River Unit 242-16	Hilcorp Alaska, LLC	Gas well, single completion	Swanson River	Sterling/Upper Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0

Notes:

1. Production data reflect reported June 2025 volumes.
2. Sterling and Upper Beluga gas pools at Swanson River include wells completed in both Sterling and Upper Beluga intervals; one listed well is completed in the Hemlock Formation and is included for completeness based on pool designation in reported production data.
3. Several wells were flowing during the reporting period and contributed to reported gas volumes, while others were shut in. Shut-in status does not indicate abandonment or loss of reservoir capability.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

SR_Center = Swanson River Central Pad

SR_34_10 = Swanson River Pad 34-10

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

6.0 SWANSON RIVER FIELD, TYONEK UNDEFINED GAS POOL (TYONEK FORMATION)

6.1 2009 Screening Context

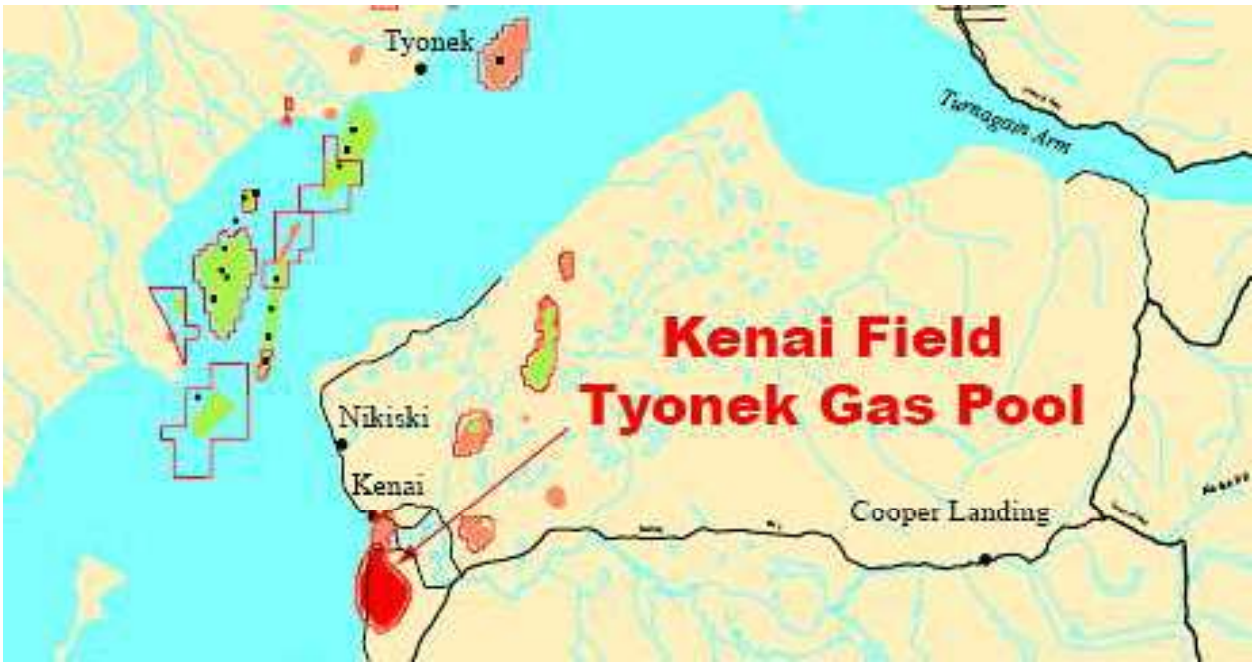
The Swanson River Field was evaluated as part of the 2009 TransCanada gas storage screening, with particular emphasis on deeper Tyonek Formation intervals due to their favorable depth, reservoir characteristics, and long-term production history. The Tyonek gas pools at Swanson River were recognized as viable candidates for underground gas storage and were distinguished from shallower producing intervals in the Sterling Formation. In the 2009 screening, these intervals were collectively referenced as 'Tyonek undefined gas' pools based on publicly reported pool summaries rather than discrete storage sand designations (Campbell 2009b, 2009c)

At the time of the screening, Tyonek reservoirs at Swanson River were considered well suited for storage applications based on prior operational experience, reservoir performance, and existing storage conversions.

The 2009 materials also noted that portions of the Swanson River Field had already been converted to gas storage operations within Tyonek Formation sands, reflecting active use of depleted pore space for seasonal gas management. This update references operational context for completeness but does not evaluate the performance, capacity, or expansion potential of existing storage operations.

Figure 6-1 shows the location and areal extent of the Swanson River Field Tyonek undefined gas pool as depicted in the Phase 2 TransCanada screening.

Figure 6-1 Swanson River Field – Tyonek Undefined Gas Pool (Tyonek Formation)



Note: Location and areal extent of the Tyonek undefined gas pool at the Swanson River Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

6.2 Ownership and Operations

Hilcorp Alaska LLC (Hilcorp) acquired the former Chevron Cook Inlet assets, including the Swanson River Field, in 2011 and is currently the operator. The field supports a combination of oil production, gas production, and gas storage operations, with Tyonek Formation reservoirs playing a central role in storage activities.

Swanson River represents one of the longest-operating underground gas storage sites in Cook Inlet.

6.3 Current Production Status

As of 2025, the Swanson River Field remains classified as producing. Production from Tyonek Formation gas intervals continues, with a combination of flowing and shut-in wells. June 2025 production records indicate that three Tyonek gas wells were flowing during the reporting period, while three additional wells were shut in. Reported gas production from Tyonek intervals totaled approximately 103 MMcf for June 2025.

6.4 Well Production Summary

Table 6-1 summarizes the current production status of wells completed in the Swanson River Field Tyonek undefined gas pool based on available June 2025 production data. The table documents

individual well status and reported production volumes and is provided to support evaluation of current operations and storage-related context.

6.5 2025 Update

The Swanson River Field continues to support active underground gas storage operations within the Tyonek Formation. Gas storage activities are documented in the Tyonek 64-5 sands, initiated in 2001, and the Tyonek 77-3 sands, initiated in 2005. These long-standing storage operations demonstrate the suitability of Tyonek reservoirs at Swanson River for gas storage applications.

The presence of active storage operations, combined with ongoing gas production, limits the availability of Tyonek intervals at Swanson River for additional third-party storage development.

Table 6-1 Swanson River Field – Tyonek Undefined Gas Pool Well Production Status

Well Name	Operator	Well Status	Area	Field	Pool	Date	Production Type	Production Method	Oil(bbl)	Gas(Mcf)	Water(bbl)	Days
Soldotna Creek Unit 43b-08	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Swanson River	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Soldotna Creek Unit 243-08	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Swanson River	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Swanson River Unit 32a-33	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Swanson River	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Swanson River Unit 224-10	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Swanson River	Tyonek Gas	6/2025	Gas Production	Flowing	0	43,492	90	30
Swanson River Unit 232-15	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Swanson River	Tyonek Gas	6/2025	Gas Production	Flowing	0	19,241	135	21
Swanson River Unit 241-33b	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Swanson River	Tyonek Gas	6/2025	Gas Production	Flowing	0	40,740	0	30

Notes:

1. Production volumes reflect reported June 2025 data.
2. "Flowing" and "Shut-In" well statuses reflect operational status at the time of reporting and do not indicate reservoir performance or long-term availability.
3. Table data are provided for status and operational context only and are not intended to represent a reassessment of gas storage suitability.

Key:

bbl = barrel
Cook Inlet Basin = regional geologic basin
Mcf = thousand cubic feet of gas
SI = shut in
SR_34_10 = Swanson River Pad 34-10
SR_Center = Swanson River Center pad
SR_SCU = Swanson River – Soldotna Creek Unit
Tyonek Gas = gas-bearing interval within the Tyonek Formation

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

7.0 IVAN RIVER FIELD, UNDEFINED GAS POOL (UPPER TYONEK FORMATION)

7.1 2009 Screening Context

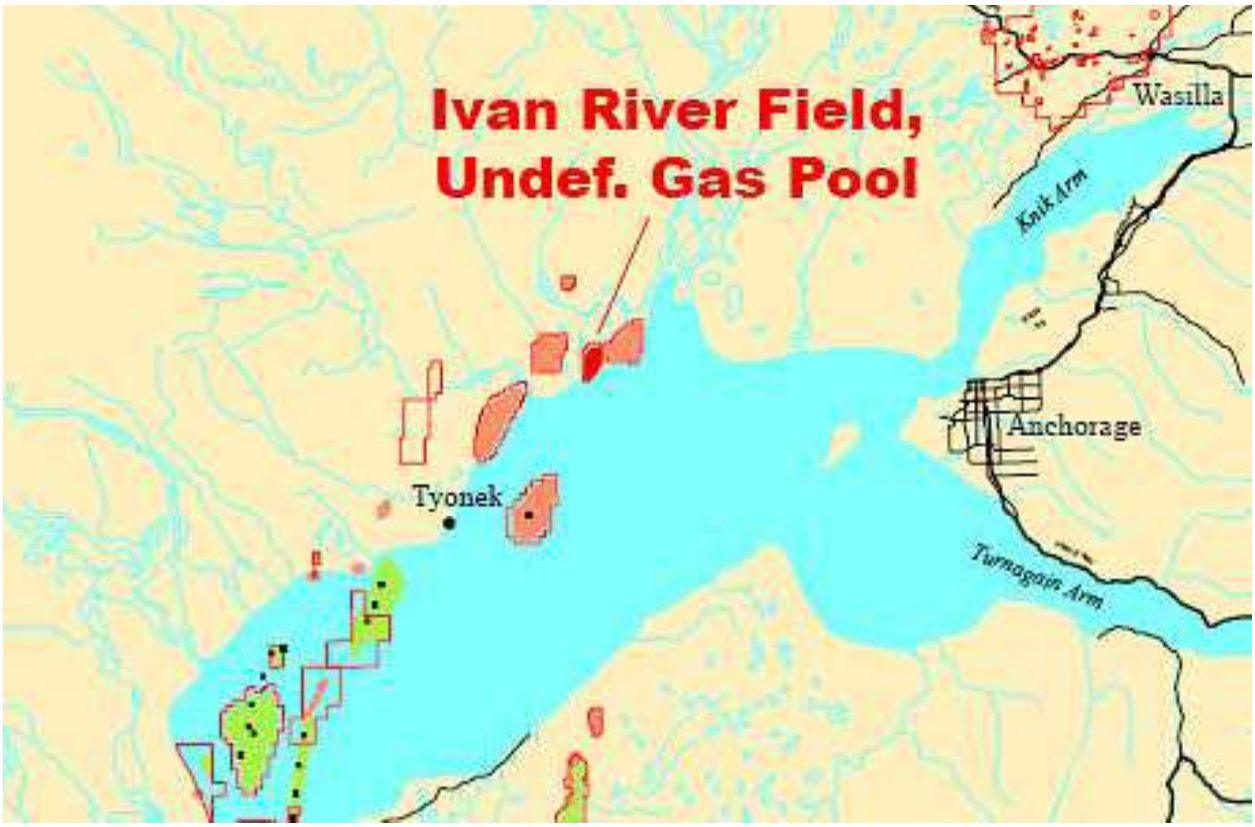
The Ivan River Field was evaluated as part of the 2009 TransCanada gas storage screening, including consideration of gas-bearing intervals within the Upper Tyonek Formation. At the time of the screening, the field was identified as a potential candidate for underground gas storage based on its location, reservoir depth, and proximity to existing infrastructure, although it did not rank among the highest-priority candidates in the final screening results.

The Upper Tyonek interval at Ivan River was distinguished from shallower producing zones and was considered separately due to its greater depth and potential suitability for storage applications.

Although the Ivan River gas pool exhibited pore-volume characteristics that were theoretically attractive for storage, the 2009 screening concluded that it was non-prospective due to its remote west-side Cook Inlet location, limited supporting infrastructure, and continued production and development potential at the time, which reduced its suitability for third-party gas storage consideration.

Figure 7-1 shows the location and areal extent of the Ivan River Field undefined gas pool as depicted in the Phase 2 TransCanada screening.

Figure 7-1 Ivan River Field – Undefined Gas Pool (Upper Tyonek Formation)



Note: Location and areal extent of the undefined gas pool at the Ivan River Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

7.2 Ownership and Operations

Ownership of the Ivan River Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Chevron Cook Inlet assets, including the Ivan River Field, in 2011 and is currently the operator. Since acquisition, Hilcorp has continued active development and management of the field, with ongoing gas production from shallower reservoir intervals.

7.3 Current Production Status

As of 2025, the Ivan River Field is classified as producing. Reported June 2025 production data indicate that gas production is occurring from multiple wells in the field, with three wells flowing and two wells shut in during the reporting period. Total reported gas production for June 2025 was approximately 128 MMcf.

Available well data indicate that current producing completions at Ivan River are within the Sterling Formation rather than the deeper Upper Tyonek interval evaluated for storage potential in the 2009 screening.

7.4 Well Production Summary

Table 7-1 summarizes the current production status of gas wells at the Ivan River Field based on available June 2025 production data. The table documents individual well status and reported production volumes and is provided to support evaluation of current operations relative to the field's historical screening for gas storage potential.

7.5 2025 Update

The Ivan River Field remains under active development by Hilcorp and continues to be managed as a producing gas asset. Current production is derived from shallow Sterling Formation completions. Development of the deeper Upper Tyonek Formation for gas storage would require drilling new wells, as existing wellbores are completed in shallower intervals and are not configured for storage operations. To date approximately 50.1 BCF of gas and 1,081,886 bbls of water have been produced from the Sterling 5.2 gas pool.

To date over 97 BCF of gas and 58,000 bbls of water have been produced from the Ivan River undefined gas pool.

Table 7-1 Ivan River Field – Undefined Gas Pool (Upper Tyonek Formation) Well Production Status

Well Name	Operator	Well Status	Pool	Date	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Ivan River Unit 44-01	Hilcorp Alaska, LLC	Gas well, single completion	Undefined Gas	6/2025	Shut-In	0	0	0	0
Ivan River Unit 41-01	Hilcorp Alaska, LLC	Gas well, single completion	Undefined Gas	6/2025	Shut-In	0	0	0	0
Ivan River Unit 44-36	Hilcorp Alaska, LLC	Gas well, single completion	Undefined Gas	6/2025	Flowing	0	33,597	33	30
Ivan River Unit 11-06	Hilcorp Alaska, LLC	Gas well, single completion	Undefined Gas	6/2025	Flowing	0	64,412	17	30
Ivan River Unit 241-01	Hilcorp Alaska, LLC	Gas well, single completion	Undefined Gas	6/2025	Flowing	0	30,085	17	30

Notes:

1. Production data reflect reported June 2025 volumes.
2. Although the pool is identified as an undefined gas pool in reporting records, current producing wells are completed in shallower intervals; development of the deeper Upper Tyonek Formation for gas storage would require additional drilling and completion of new wells.
3. Several wells were flowing during the reporting period and contributed to reported gas volumes, while others were shut in. Shut-in status does not indicate abandonment or loss of reservoir capability.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Ivan_River = Ivan River field/pad designation

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

8.0 KENAI FIELD – CANNERY LOOP UNIT, UPPER TYONEK GAS POOL (UPPER TYONEK FORMATION)

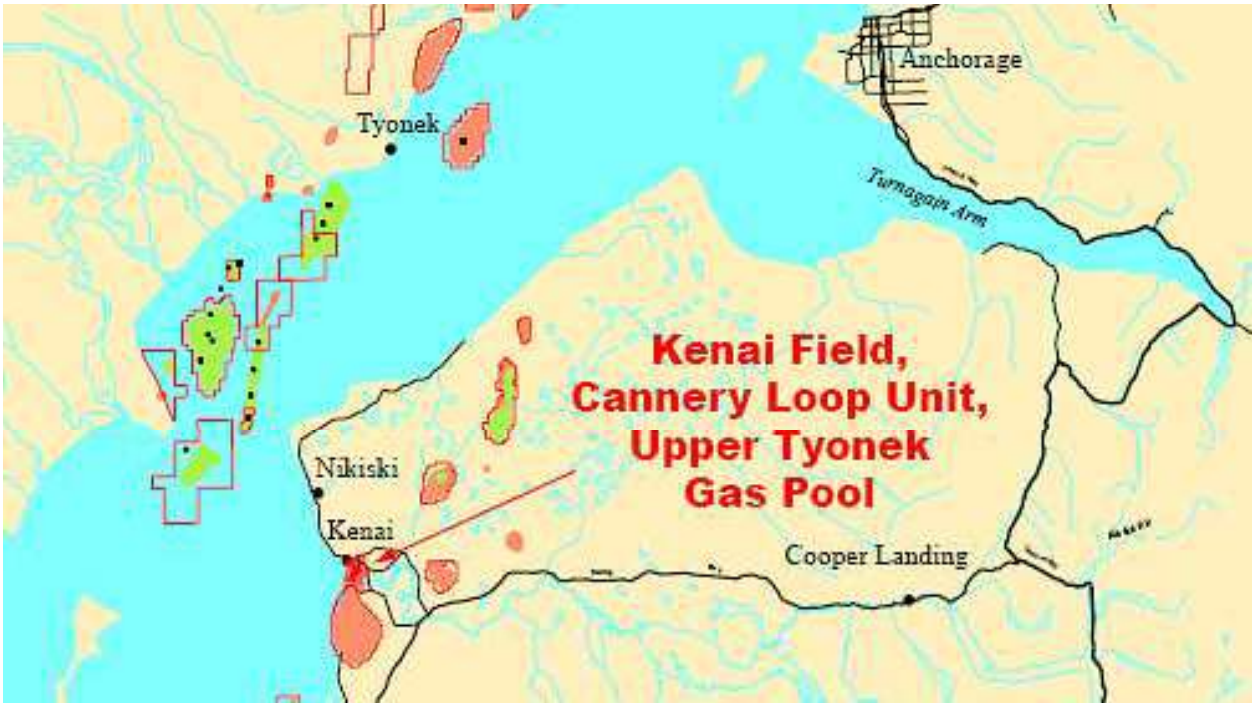
8.1 2009 Screening Context

The Upper Tyonek gas pool at the Cannery Loop Unit (CLU) within the Kenai Field was evaluated as part of the 2009 TransCanada gas storage screening. The pool was identified as a potentially attractive candidate for gas storage due to its stratigraphic position, reservoir performance history, and proximity to surface infrastructure. Its location immediately beneath the interval later developed as the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility further highlighted its relevance to storage considerations.

The 2009 screening identified the Upper Tyonek (Tyonek T-1) interval at Cannery Loop as locally attractive based on earlier production performance, including strong pre-impairment gas deliverability, and its position immediately beneath the interval later developed for gas storage. However, the materials noted a history of operational impairment, including a 2002 tubing failure and formation damage that prevented reestablishing production, as well as uncertainty regarding sand continuity and water behavior, with some wells exhibiting early water production while others produced relatively dry gas. These subsurface factors were cited as warranting additional investigation but are not reevaluated as part of this 2025 update (Campbell 2009b, 2009c).

Figure 8-1 shows the location and areal extent of the Cannery Loop Unit Upper Tyonek gas pool as depicted in the Phase 2 TransCanada screening.

Figure 8-1 Kenai Field – Cannery Loop Unit Upper Tyonek Gas Pool (Upper Tyonek Formation)



Source: Location and areal extent of the Upper Tyonek gas pool at the Cannery Loop Unit as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b).

8.2 Ownership and Operations

Ownership and operational control of the Cannery Loop Unit have changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the operator of the Kenai Field and the Cannery Loop Unit. Hilcorp continues to manage active production and storage assets within the unit across multiple stratigraphic intervals.

8.3 Current Production Status

As of 2025, the Cannery Loop Unit is classified as producing; however, the Upper Tyonek gas pool addressed in this section is currently shut in. June 2025 production records indicate no reported gas production from the Upper Tyonek pool. Available well data indicate that two Upper Tyonek gas wells are completed within the unit and are currently shut in.

8.4 Well Production Summary

Table 8-1 summarizes the current production status of wells completed in the Cannery Loop Unit Upper Tyonek gas pool based on available June 2025 production data. The table documents

individual well status and recent production history and is provided to support evaluation of the pool's current operational condition relative to its historical performance.

8.5 2025 Update

The Upper Tyonek gas pool at the Cannery Loop Unit has a well-documented production history. Between 1988 and 2002, the CLU-1 well produced approximately 36 bcf of relatively water-free gas from the Tyonek T-1 sand. In 2002, a tubing failure resulted in the introduction of freshwater packer fluid into the reservoir, leading to formation damage and loss of production. Although the mechanical issue was corrected, production could not be reestablished from the affected well.

To recover remaining reserves from the Tyonek T-1 sand, the CLU-1RD well was drilled in 2003 and subsequently produced an additional approximately 12 bcf of gas. Later Upper Tyonek completions, including CLU-5 and CLU-5RD, experienced early water production, resulting in watered-out conditions and cessation of economic gas production.

In total the CLU Tyonek gas pool produced 82 BCF from 1988 to 2023 making it approximately three times larger than the Sterling C reservoir at CINGSA. Given the pool's proximity to the CINGSA storage interval and its historical gas recovery performance, the 2009 materials identified this interval as warranting further technical review; however, such analysis is beyond the scope of this 2025 status update.

Table 8-1 Kenai Field – Cannery Loop Unit, Upper Tyonek Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Cannery Loop Unit 01RD	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Upper Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Cannery Loop Unit 04	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Upper Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0

Notes:

1. Production data reflect reported June 2025 volumes.
2. Both wells completed in the Upper Tyonek gas pool at the Cannery Loop Unit were shut in during the reporting period; zero production does not indicate abandonment or loss of reservoir capability.
3. The Upper Tyonek interval lies immediately beneath the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility and has been historically evaluated for gas storage potential based on reservoir performance and stratigraphic position.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

CLU = Cannery Loop Unit

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

9.0 KENAI FIELD – CANNERY LOOP UNIT, BELUGA GAS POOL (BELUGA FORMATION)

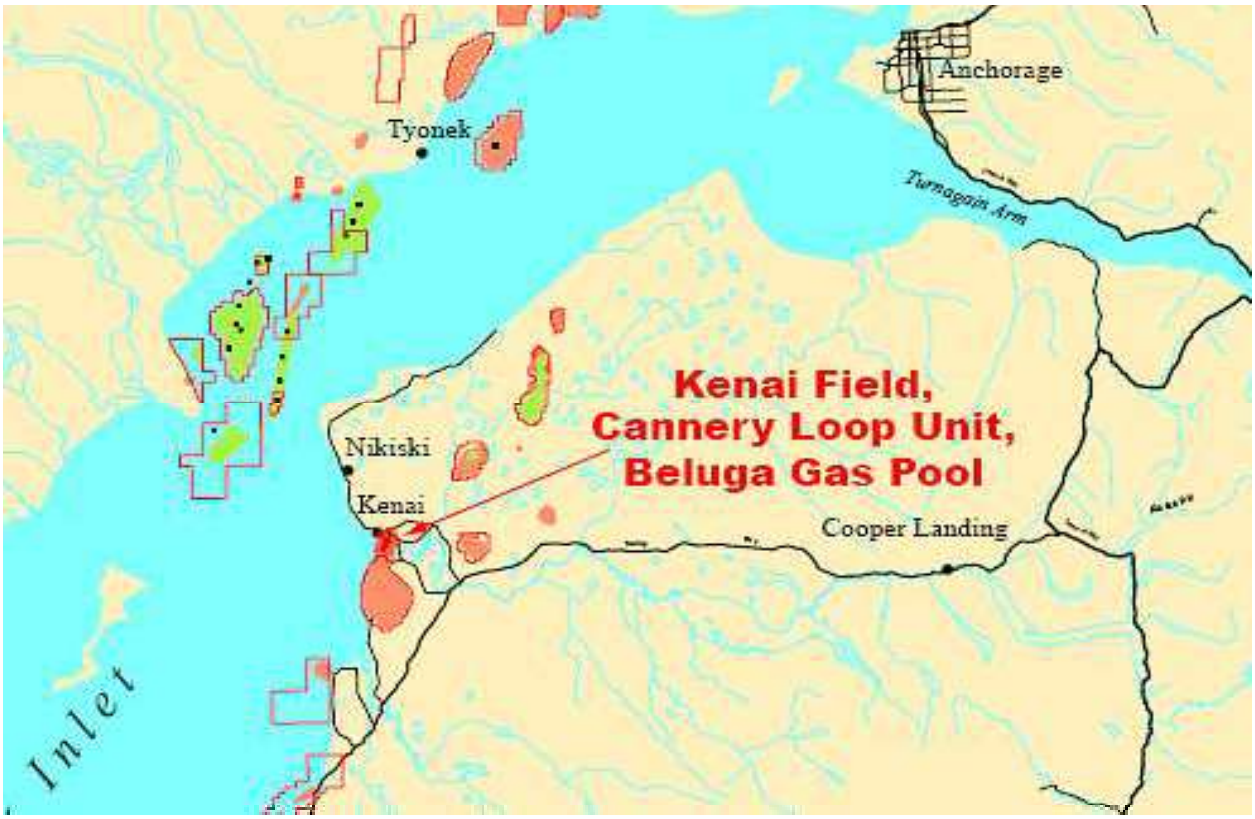
9.1 2009 Screening Context

The Beluga gas pool at the Cannery Loop Unit (CLU) within the Kenai Field was evaluated as part of the 2009 TransCanada gas storage screening. At the time of the screening, Beluga Formation reservoirs at Cannery Loop were considered in the context of mature production performance, reservoir continuity, and proximity to infrastructure. However, the Beluga gas pool did not rank among the highest-priority candidates for gas storage development due to its continued role as an actively producing reservoir.

The Beluga interval was distinguished from deeper Tyonek reservoirs that were more favorably positioned for potential storage applications. As documented in the Phase 2 screening, continued production activity and reservoir utilization reduced the suitability of the Beluga interval for storage conversion relative to deeper, more depleted pools (Campbell 2009b).

Figure 9-1 shows the location and areal extent of the Cannery Loop Unit Beluga gas pool as depicted in the Phase 2 TransCanada screening.

Figure 9-1 Kenai Field – Cannery Loop Unit Beluga Gas Pool (Beluga Formation)



Note: Location and areal extent of the Beluga gas pool at the Cannery Loop Unit as depicted in the Phase 2 TransCanada gas storage screening.
Source: Campbell (2009b).

9.2 Ownership and Operations

Ownership and operational control of the Cannery Loop Unit have changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the operator of the Kenai Field and the Cannery Loop Unit. Since acquisition, Hilcorp has actively developed and produced the Beluga gas pool as part of ongoing field operations.

The Cannery Loop Unit continues to serve as a core producing area within the Kenai Field, supporting multiple flowing Beluga gas completions.

9.3 Current Production Status

As of 2025, the Cannery Loop Unit is classified as producing, with the Beluga gas pool remaining in active production. June 2025 production records indicate that seven Beluga gas wells were flowing during the reporting period, while three additional wells were shut in. Reported gas production from the Beluga gas pool totaled approximately 125 MMcf for June 2025.

Water production is present in several producing wells, reflecting mature reservoir conditions consistent with long-term production history.

9.4 Well Production Summary

Table 9-1 summarizes the current production status of wells completed in the Cannery Loop Unit Beluga gas pool based on available June 2025 production data. The table documents individual well status, production method, and reported gas and water volumes and is provided to support evaluation of current operations relative to historical screening considerations.

9.5 2025 Update

The Beluga gas pool at the Cannery Loop Unit remains under active development and production by Hilcorp. Ongoing production activity indicates that the Beluga Formation continues to be managed as a primary producing interval rather than as a candidate for depletion-based gas storage conversion. In total the pool has produced over 110 BCF of gas and 2.5 MM bbls of water from 1989 to present.

The continued operational importance of the Beluga gas pool limits its availability for third-party gas storage development despite its proximity to existing infrastructure and deeper storage intervals within the Cannery Loop Unit.

Table 9-1 Kenai Field – Cannery Loop Unit, Beluga Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Cannery Loop Unit 01RD	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	16,508	0	30
Cannery Loop Unit 03	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Cannery Loop Unit 04	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Cannery Loop Unit 05RD2	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	15,896	156	30
Cannery Loop Unit 09	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	35,533	271	30
Cannery Loop Unit 10RD2	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	10,105	228	30
Cannery Loop Unit 13	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Cannery Loop Unit 14	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	5,045	134	30
Cannery Loop Unit 15	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	31,501	114	30
Cannery Loop Unit 16	Hilcorp Alaska, LLC	Gas well, single completion	Kenai CLU	Beluga Gas	6/2025	Gas Production	Flowing	0	10,515	339	30

Notes:

1. Production data reflect reported June 2025 volumes.
2. The Beluga gas pool at the Cannery Loop Unit includes multiple flowing wells and remains an actively producing reservoir. Shut-in wells listed were not producing during the reporting period; shut-in status does not indicate abandonment or loss of reservoir capability.
3. The Beluga interval continues to be managed as a production asset and was not prioritized for gas storage development in the 2009 TransCanada screening relative to deeper Tyonek reservoirs.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key: bbl = barrel CLU = Cannery Loop Unit Mcf = thousand cubic feet of gas SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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10.0 BEAVER CREEK FIELD, BELUGA GAS POOL (BELUGA FORMATION)

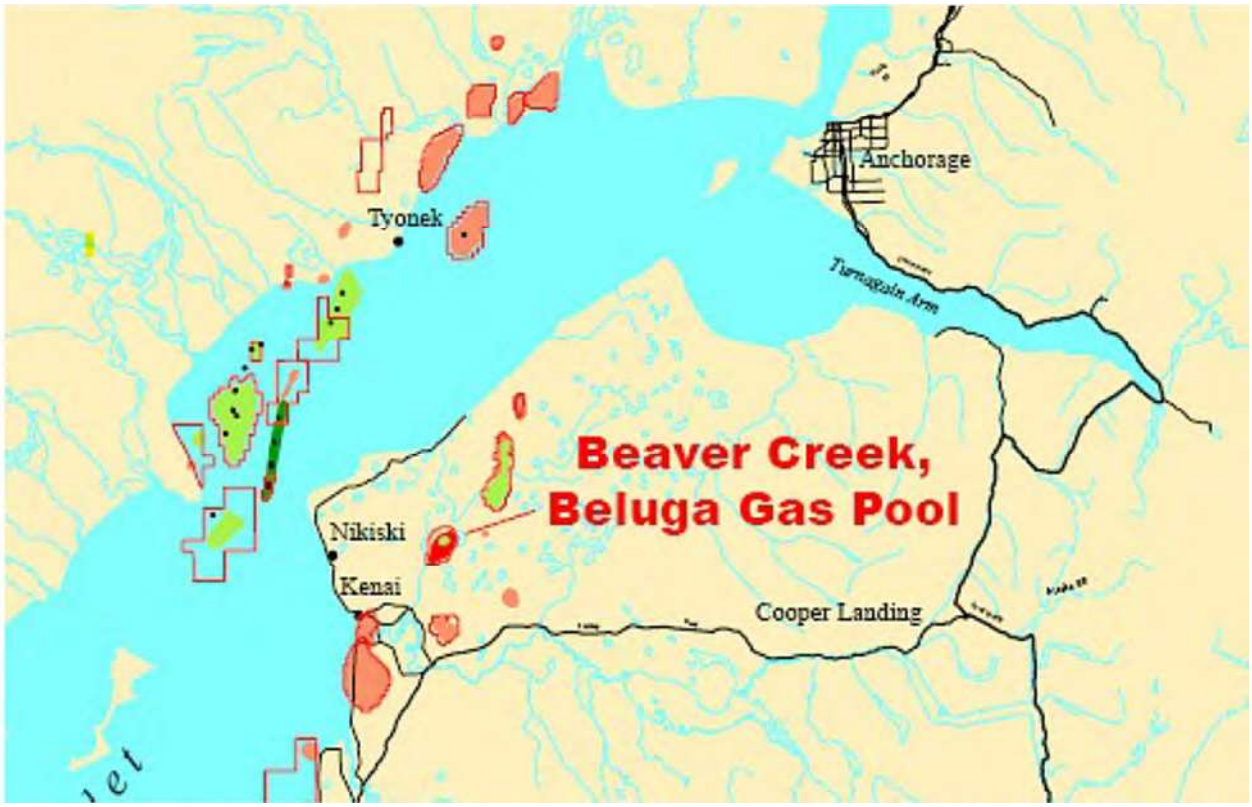
10.1 2009 Screening Context

The Beluga gas pool at the Beaver Creek Field was evaluated as part of the 2009 TransCanada gas storage screening. Beluga Formation reservoirs were considered in the context of mature Cook Inlet production fields with established infrastructure and stacked reservoir intervals. At the time of the screening, the Beaver Creek Beluga gas pool was not identified as a priority candidate for gas storage development due to its continued role as an actively producing reservoir.

The Beluga interval at Beaver Creek was distinguished from deeper reservoirs that were more favorably positioned for potential gas storage applications based on relative depletion state and continued production utilization (Campbell 2009b).

Figure 10-1 shows the location and areal extent of the Beaver Creek Field Beluga gas pool as depicted in the Phase 2 TransCanada screening.

Figure 10-1 Beaver Creek Field – Beluga Gas Pool (Beluga Formation)



Note: Location and areal extent of the Beluga gas pool at the Beaver Creek Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

10.2 Ownership and Operations

Ownership of the Beaver Creek Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the operator of the Beaver Creek Unit. Since acquisition, Hilcorp has remained an active operator in the field and continues to pursue drilling, sidetracking, and optimization activities across multiple producing intervals.

The Beaver Creek Field continues to serve as an actively developed production asset within Cook Inlet.

10.3 Current Production Status

As of 2025, the Beaver Creek Field is classified as producing, with the Beluga gas pool remaining in active production. June 2025 production records indicate that nine Beluga gas wells were flowing during the reporting period, while two additional wells were shut in. Reported gas production from the Beluga gas pool totaled approximately 114 MMcf for June 2025.

Several producing wells exhibit associated water production, reflecting mature reservoir conditions and ongoing field management practices.

10.4 Well Production Summary

Table 10-1 summarizes the current production status of wells completed in the Beaver Creek Field Beluga gas pool based on available June 2025 production data. The table documents individual well status, completion type, production method, and reported gas and water volumes and is provided to support evaluation of current operations relative to historical screening considerations.

10.5 2025 Update

The Beaver Creek Field remains under active development by Hilcorp. Ongoing drilling and sidetrack activities indicate that the Beluga gas pool continues to be managed as a primary producing interval. The continued operational use of the Beluga gas pool limits its availability for third-party gas storage development despite the presence of infrastructure and stacked reservoirs within the Beaver Creek Field. To date over 104 BCF of gas and 1,000,000 bbls of water have been produced from the Beaver Creek Beluga gas pool.

Table 10-1 Beaver Creek Field – Beluga Gas Pool Well Production Status

Well Name	Operator	Well Status	Area	Field	Pool	Date	Production Type	Production Method	Oil(bbl)	Gas(Mcf)	Water(bbl)	Days
Beaver Creek Unit 24	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	5,654	8	30
Beaver Creek Unit 23	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Gas Lift	0	11,059	110	30
Beaver Creek Unit 18RD	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	6,375	697	27
Beaver Creek Unit 19RD	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	11,128	8	30
Beaver Creek Unit 16RD	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	34,646	175	30
Beaver Creek Unit 12A	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Beaver Creek Unit 13	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	14,181	1,232	28

Well Name	Operator	Well Status	Area	Field	Pool	Date	Production Type	Production Method	Oil(bbl)	Gas(Mcf)	Water(bbl)	Days
Beaver Creek Unit 11a	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	9,126	31	30
Beaver Creek Unit 09a	Hilcorp Alaska, LLC	Gas well, dual completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	8,942	0	30
Beaver Creek Unit 07a	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Beaver Creek Unit 1b	Hilcorp Alaska, LLC	Gas well, single completion	Cook Inlet Basin	Beaver Creek	Beluga Gas	6/2025	Gas Production	Flowing	0	13,723	426	30

Notes:

1. Production data reflect reported June 2025 volumes.
2. The Beluga gas pool at the Beaver Creek Field includes multiple flowing wells and remains an actively producing reservoir. Two wells were shut in during the reporting period; shut-in status does not indicate abandonment or loss of reservoir capability.
3. Reported production methods include flowing wells and gas lift operations, reflecting ongoing active field management.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

11.0 KENAI LOOP FIELD, UPPER TYONEK GAS POOL (TYONEK FORMATION)

11.1 2009 Screening Context

The Kenai Loop Field was not included in the original 2009 TransCanada gas storage screening because the field was discovered after completion of that study. Gas-bearing intervals within the Tyonek Formation at Kenai Loop were identified following drilling activity in 2011, subsequent to the original basin-wide screening effort.

As a result, the Upper Tyonek gas pool at Kenai Loop represents a post-2009 addition to the set of Cook Inlet gas reservoirs considered in this update.

Because the Kenai Loop Field was discovered after completion of the 2009 TransCanada screening, it does not have a corresponding Phase 1 or Phase 2 screening map or ranking.

11.2 Ownership and Operations

The Kenai Loop Field is owned and operated by AIX Energy LLC (AIX). Unlike most mature Cook Inlet gas fields evaluated in this report, Kenai Loop is not owned or operated by Hilcorp Alaska LLC. The field therefore represents a distinct ownership and operational case relative to other candidates originally screened by TransCanada.

AIX continues to manage active production operations at Kenai Loop, with development focused on Tyonek Formation gas reservoirs.

11.3 Current Production Status

As of 2025, the Kenai Loop Field is classified as producing. Production from the Upper Tyonek gas pool remains active, with one gas well flowing and two additional wells shut in during the reporting period. June 2025 production records indicate reported gas production of approximately 50 MMcf from the field.

Available data indicate that current producing completions are within the Tyonek Formation and are not commingled with other producing intervals.

11.4 Well Production Summary

Table 11-1 summarizes the current production status of wells completed in the Kenai Loop Field Upper Tyonek gas pool based on available June 2025 production data. The table documents

individual well status, production method, and reported gas and water volumes and is provided to support evaluation of the field's current operational status.

11.5 2025 Update

The Kenai Loop Field remains under active development by AIX. Unlike most fields evaluated in this report, Kenai Loop is not under Hilcorp ownership and has not been incorporated into existing Cook Inlet gas storage operations. The field therefore remains under review by ENSTAR for potential gas storage applications.

Discovered in 2011, the Kenai Loop Field is relatively young compared to other fields evaluated in this study. Its ownership status, production history, and reservoir characteristics distinguish it from long-established producing and storage assets in Cook Inlet and contribute to its continued relevance in ENSTAR's evaluation of potential gas storage resources. To date over 28 BCF of gas and 13,000 bbls of water have been produced from the Kenai Loop Tyonek gas pool.

Table 11-1 Kenai Loop Field – Upper Tyonek Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Method	Oil(bbl)	Gas(Mcf)	Water(bbl)	Days
Kenai Loop 1-4	AIX Energy LLC	Gas well, single completion	Kenai Loop	Undefined Gas	6/2025	Shut-In	0	0	0	0
Kenai Loop 1-3	AIX Energy LLC	Gas well, single completion	Kenai Loop	Undefined Gas	6/2025	Flowing	0	0	0	0
Kenai Loop 1-1	AIX Energy LLC	Gas well, single completion	Kenai Loop	Undefined Gas	6/2025	Flowing	0	50,657	61	30

Notes:

1. Production data reflect reported June 2025 volumes.
2. The Kenai Loop Field includes one flowing well that accounted for all reported gas production during the reporting period; other wells were shut in. Shut-in status does not indicate abandonment or loss of reservoir capability.
3. The Kenai Loop Field was not included in the 2009 TransCanada screening due to the timing of discovery and drilling and is presented here to document current operational status and relevance to ongoing gas storage considerations.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

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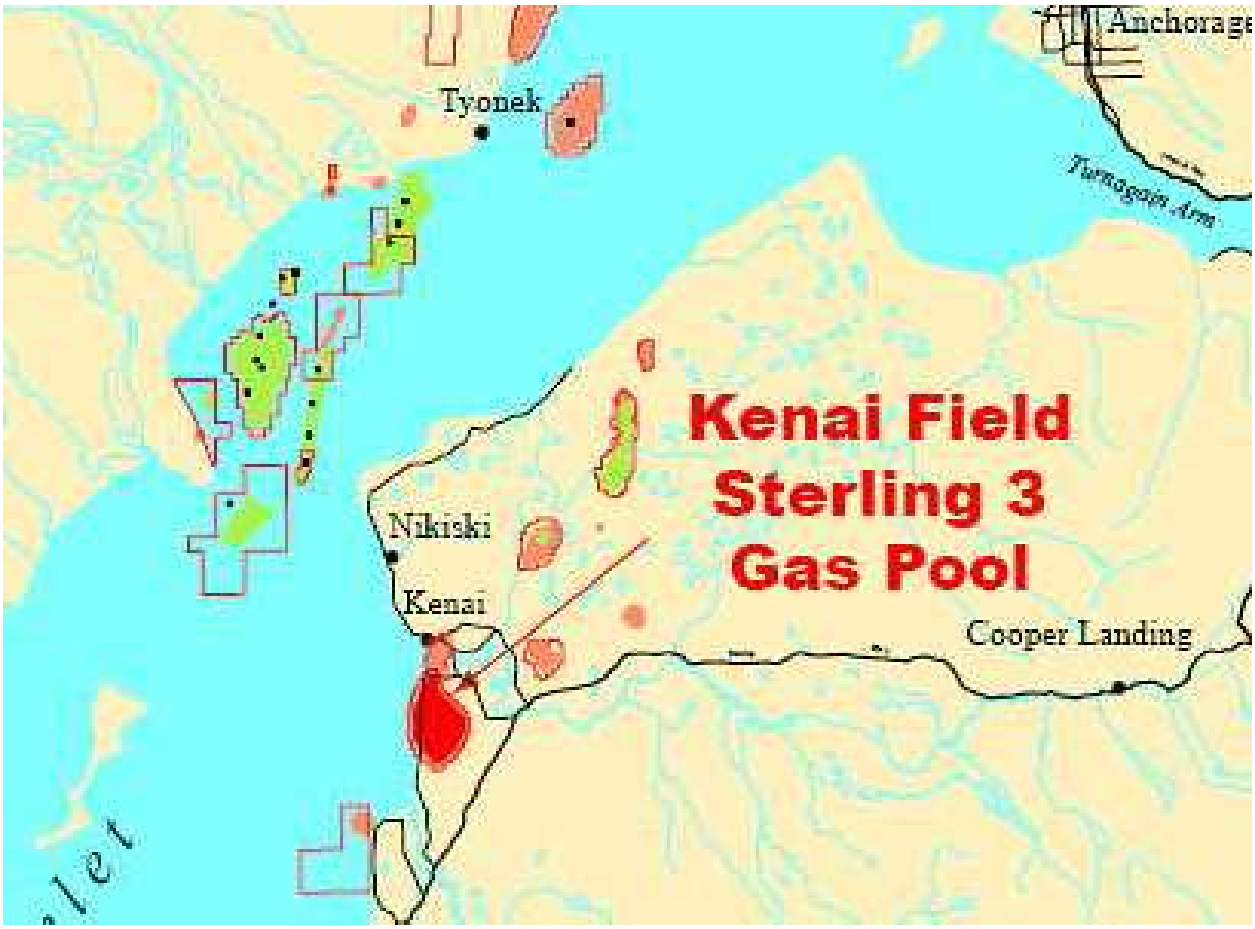
12.0 KENAI FIELD, STERLING 3 GAS POOL (STERLING FORMATION)

12.1 2009 Screening Context

The Sterling 3 gas pool within the Kenai Field was evaluated as part of the 2009 TransCanada gas storage screening. Sterling Formation reservoirs at Kenai were reviewed in the context of mature production performance, stacked reservoir development, and proximity to infrastructure. While several Sterling intervals were identified as prospective during the original screening, the Sterling 3 gas pool was not among the highest-ranked candidates for gas storage development due to its continued production role and the presence of deeper reservoirs more suitable for storage applications. Figure 12-1 shows the location and areal extent of the Kenai Field Sterling 3 gas pool as depicted in the Phase 2 TransCanada screening.

Figure 12-1 Kenai Field – Sterling 3 Gas Pool (Sterling Formation)



Notes: Location and areal extent of the Sterling 3 gas pool at the Kenai Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

12.2 Ownership and Operations

Ownership of the Kenai Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the operator. Since acquisition, Hilcorp has continued active development and management of the Kenai Field across multiple producing and storage intervals.

12.3 Current Production Status

As of 2025, the Kenai Field is classified as producing. Production from the Sterling 3 gas pool remains limited, with the majority of completed wells currently shut in. June 2025 production records indicate that one Sterling 3 gas well was flowing during the reporting period, while eleven additional completed wells were shut in. Reported gas production from the Sterling 3 gas pool totaled approximately 7 MMcf for June 2025.

The limited production activity and high number of shut-in wells reflect mature reservoir conditions and field-level operational priorities.

12.4 Well Production Summary

Table 12-1 summarizes the current production status of wells completed in the Kenai Field Sterling 3 gas pool based on available June 2025 production data. The table documents individual well status, production method, and reported gas volumes and is provided to support evaluation of current operations relative to historical screening considerations.

12.5 2025 Update

The Kenai Field remains under active development by Hilcorp. While the Sterling 3 gas pool continues to be managed as a producing interval, operational emphasis within the field includes gas storage activities in deeper reservoir intervals.

Hilcorp utilizes an underlying reservoir, commonly referred to as Pool 6, for gas storage operations. These storage activities are distinct from production in the Sterling 3 gas pool and do not involve the Sterling Formation. The continued production and storage use of the Kenai Field limits the availability of the Sterling 3 gas pool for third-party gas storage development despite its proximity to existing infrastructure. To date over 335 BCF of gas and 165,000 bbls of water have been produced from the Sterling 3 gas pool.

Table 12-1 Kenai Field – Sterling 3 Gas Pool Well Production Status

Well Name	Operator	Field	Pool	Date	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Kenai Unit 44-08	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Unit 43-07	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Unit 33-30	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Unit 21-05	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Deep Unit 2 (21-8)	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Deep Unit 5	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Unit 43-12	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Deep Unit 6	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Beluga Unit 42-07RD	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Flowing	0	7,762	0	30
Kenai Beluga Unit 11-8Y	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Beluga Unit 41-07X	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0
Kenai Deep Unit	Hilcorp Alaska, LLC	Kenai	Sterling 3 Gas	6/2025	Shut-In	0	0	0	0

Notes:

1. Production data reflect reported June 2025 volumes.
2. Most wells completed in the Sterling 3 gas pool were shut in during the reporting period; one well was flowing and accounted for all reported gas production. Shut-in status does not indicate abandonment or loss of reservoir capability.
3. The Sterling 3 gas pool continues to be managed as part of active Kenai Field operations and is not being evaluated independently for gas storage conversion in this review.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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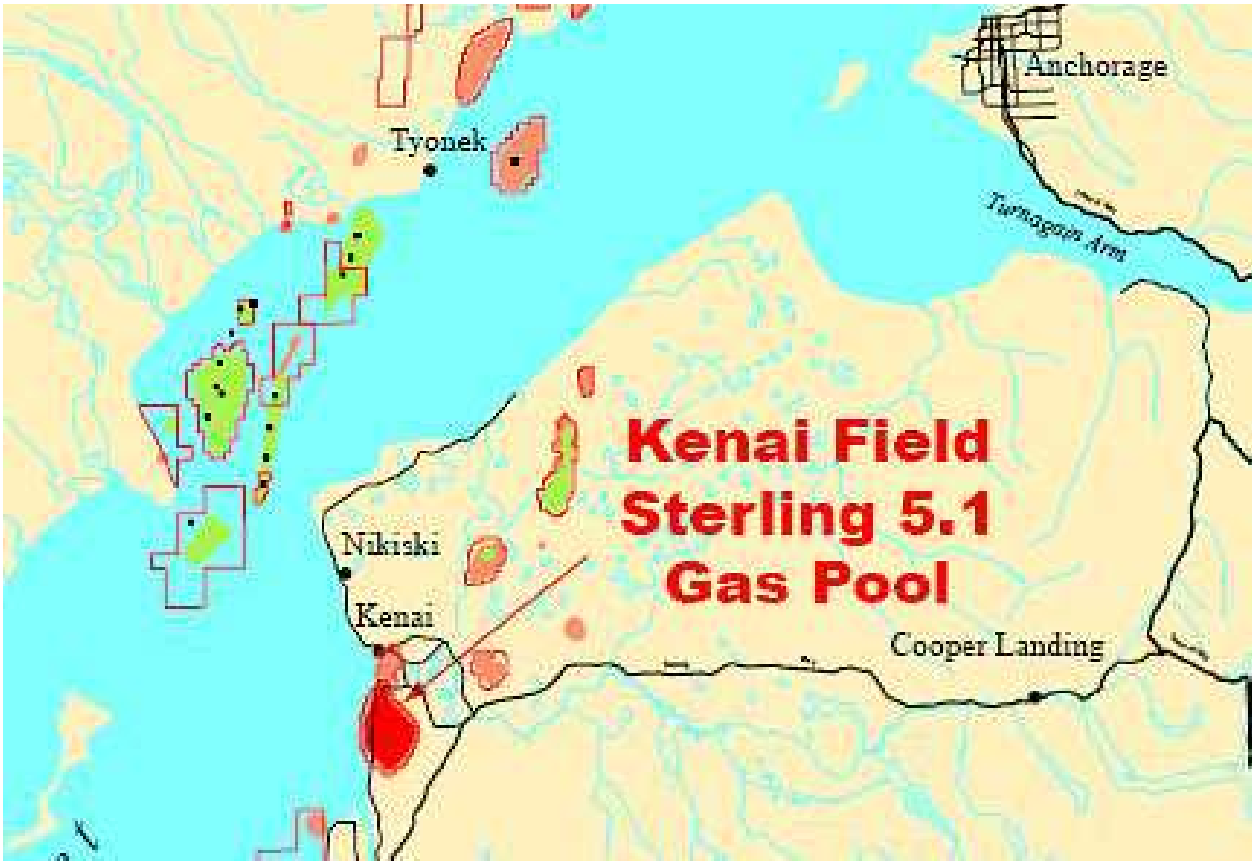
13.0 KENAI FIELD, STERLING 5.1 GAS POOL (STERLING FORMATION)

13.1 2009 Screening Context

The Sterling 5.1 gas pool within the Kenai Field was evaluated as part of the 2009 TransCanada gas storage screening. Sterling Formation reservoirs were reviewed in the context of mature production performance, stacked reservoir development, and proximity to infrastructure. While several Sterling intervals at Kenai were identified as potentially prospective during early screening phases, the Sterling 5.1 gas pool was not ranked among the highest-priority candidates for gas storage development due to its continued operational role and the presence of deeper reservoirs more favorably positioned for storage applications.

Figure 13-1 shows the location and areal extent of the Kenai Field Sterling 5.1 gas pool as depicted in the Phase 2 TransCanada screening.

Figure 13-1 Kenai Field – Sterling 5.1 Gas Pool (Sterling Formation)



Note: Location and areal extent of the Sterling 5.1 gas pool at the Kenai Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

13.2 Ownership and Operations

Ownership of the Kenai Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the operator. Since acquisition, Hilcorp has continued active management of the Kenai Field across multiple producing and storage intervals.

Several wells completed in the Sterling 5.1 gas pool are configured as dual completions or are associated with storage-related infrastructure, although production from the Sterling 5.1 interval itself is currently suspended.

13.3 Current Production Status

As of 2025, the Kenai Field remains classified as producing; however, production from the Sterling 5.1 gas pool is currently shut in. June 2025 production records indicate that all eight Sterling 5.1 gas wells were shut in during the reporting period, with no reported gas production from the pool.

The presence of multiple shut-in wells, including wells described as dual completions or produce-only storage-associated wells, reflects the pool's mature status and field-level operational priorities.

13.4 Well Production Summary

Table 13-1 summarizes the current production status of wells completed in the Kenai Field Sterling 5.1 gas pool based on available June 2025 production data. The table documents individual well configurations and shut-in status and is provided to support evaluation of current operations relative to historical screening considerations.

13.5 2025 Update

The Kenai Field remains under active development by Hilcorp. While the Sterling 5.1 gas pool is currently shut in, the field continues to support both production and gas storage activities in other reservoir intervals.

Hilcorp utilizes an underlying reservoir, commonly referred to as Pool 6, for gas storage operations. These storage activities are distinct from the Sterling 5.1 gas pool and do not involve active production from the Sterling Formation. The current operational role of the Kenai Field limits the availability of the Sterling 5.1 gas pool for third-party gas storage development despite its proximity to infrastructure and favorable reservoir characteristics identified in earlier screening efforts.

To date over 484 BCF of gas and 176,000 bbls of water have been produced from the Sterling 5.1 gas pool.

Table 13-1 Kenai Field – Sterling 5.1 Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method
Kenai Unit 21-05	Hilcorp Alaska, LLC	Gas well, dual completion	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Unit 13-06	Hilcorp Alaska, LLC	Gas well, dual & storage well; produce only	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Deep Unit 9	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Unit 11-08	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Unit 14-32	Hilcorp Alaska, LLC	Gas well, dual & storage well; produce only	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Beluga Unit 33-06	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Unit 43-07	Hilcorp Alaska, LLC	Gas well, dual completion	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In
Kenai Unit 34-32	Hilcorp Alaska, LLC	Gas well, dual & storage well; produce only	Kenai	Sterling 5.1 Gas	6/2025	Gas Production	Shut-In

Notes:

1. Production data reflect reported June 2025 volumes.
2. All wells completed in the Sterling 5.1 gas pool were shut in during the reporting period; zero production does not indicate abandonment or loss of reservoir capability.
3. Several wells in this pool are configured as dual completions or storage-capable wells operated in produce-only mode, reflecting integration of the Sterling 5.1 interval within broader Kenai Field development and gas storage operations.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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14.0 KENAI FIELD, TYONEK GAS POOL (TYONEK FORMATION)

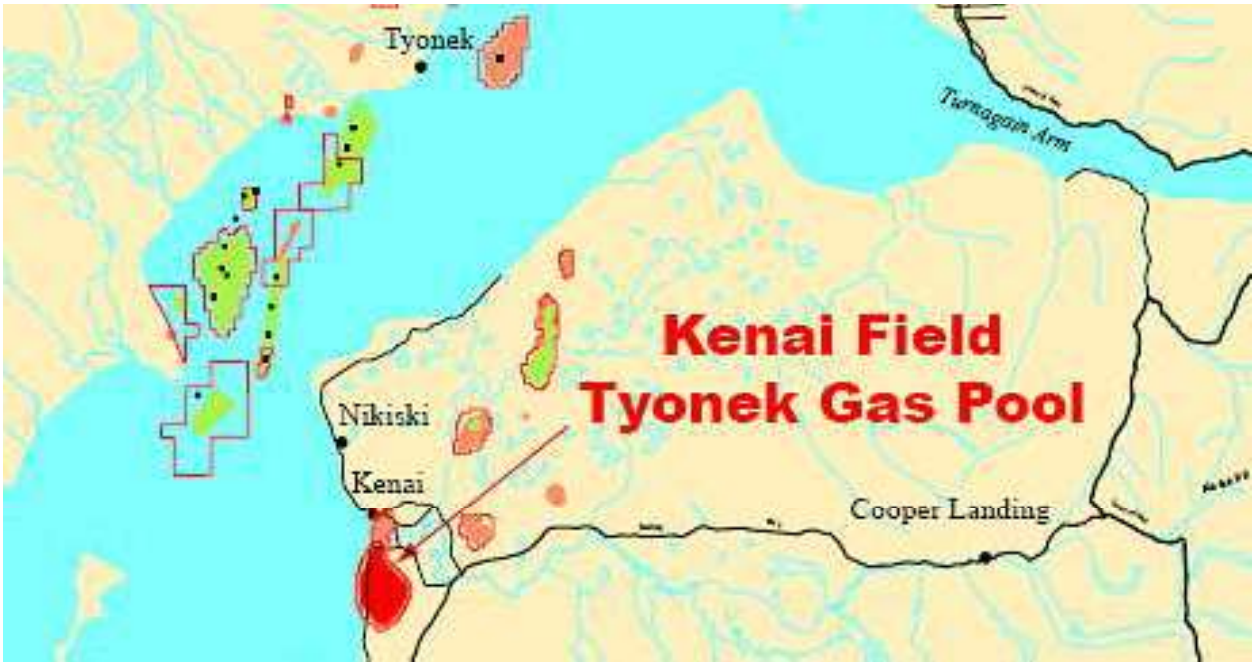
14.1 2009 Screening Context

The Tyonek gas pool within the Kenai Field was evaluated as part of the 2009 TransCanada gas storage screening. Tyonek Formation reservoirs at Kenai were identified as potentially suitable for gas storage based on their depth, reservoir characteristics, and separation from shallower producing intervals. In the original screening, Tyonek reservoirs were generally considered more favorable for storage applications than Sterling Formation gas pools due to their stratigraphic position and historical performance.

The Kenai Field Tyonek gas pool was therefore distinguished as a relevant component of the original evaluation, although subsequent field development has altered its operational role.

Figure 14-1 shows the location and areal extent of the Kenai Field Tyonek gas pool as depicted in the Phase 2 TransCanada screening.

Figure 14-1 Kenai Field – Tyonek Gas Pool (Tyonek Formation)



Note: Location and areal extent of the Tyonek gas pool at the Kenai Field as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b)

14.2 Ownership and Operations

Ownership of the Kenai Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the

operator. Since acquisition, Hilcorp has actively managed the Kenai Field across multiple producing and storage intervals, including Tyonek and Beluga reservoirs.

The Kenai Field supports a complex combination of gas production and storage operations, with well completions spanning multiple formations.

14.3 Current Production Status

As of 2025, the Kenai Field remains classified as producing. Production from the Tyonek gas pool remains active, with a combination of flowing and shut-in wells. June 2025 production records indicate that five Tyonek gas wells were flowing during the reporting period, while five additional wells were shut in. Reported gas production attributable to Tyonek and commingled Beluga/Upper Tyonek completions totaled approximately 112 MMcf for June 2025.

Several producing wells are reported as commingled Beluga/Upper Tyonek completions, reflecting current well configuration and public reporting designations rather than discrete reservoir performance.

14.4 Well Production Summary

Table 14-1 summarizes the current production status of wells completed in the Kenai Field Tyonek gas pool and associated commingled Beluga/Upper Tyonek intervals based on available June 2025 production data. The table documents individual well status, completion intervals, and reported gas and water volumes and is provided to support evaluation of current operations relative to historical screening considerations.

14.5 2025 Update

The Kenai Field remains under active development by Hilcorp. While Tyonek gas production continues, the field also supports gas storage operations in a stratigraphically separate interval commonly referred to as Pool 6. These storage activities are located above the Tyonek gas pool and are operationally distinct from Tyonek production wells.

The concurrent use of the Kenai Field for gas production and gas storage limits the availability of Tyonek reservoirs for additional third-party gas storage development despite their favorable characteristics identified in earlier screening efforts.

Table 14-1 Kenai Field – Tyonek Gas Pool Well Production Status

Well Name	Operator	Well Status	Field	Pool	Date	Production Type	Production Method	Oil (bbl)	Gas (Mcf)	Water (bbl)	Days
Kenai Unit 11-07x	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Unit 24-05b	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Unit 41-08	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Unit 23-07a	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Tyonek Gas	6/2025	Gas Production	Flowing	0	20,461	62	30
Kenai Unit 13-06a	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Unit 41-18x	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Beluga/ Upper Tyonek Gas	6/2025	Gas Production	Flowing	0	14,140	122	30
Kenai Unit 14-05	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Tyonek Gas	6/2025	Gas Production	Shut-In	0	0	0	0
Kenai Unit 14-05s	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Beluga/ Upper Tyonek Gas	6/2025	Gas Production	Flowing	0	13,290	127	30
Kenai Unit 33-08	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Beluga/ Upper Tyonek Gas	6/2025	Gas Production	Flowing	0	49,757	0	30
Kenai Unit 24-05b	Hilcorp Alaska, LLC	Gas well, single completion	Kenai	Beluga/ Upper Tyonek Gas	6/2025	Gas Production	Flowing	0	15,372	101	30

Notes:

1. Production data reflect reported June 2025 volumes.
2. The Tyonek gas pool at the Kenai Field includes wells completed in both Tyonek and combined Beluga/Upper Tyonek intervals. Several wells were flowing during the reporting period and contributed to reported gas volumes, while others were shut in. Shut-in status does not indicate abandonment or loss of reservoir capability.
3. Wells completed in combined Beluga/Upper Tyonek intervals are included to reflect operational reporting designations and current completion configurations.
4. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

15.0 STERLING FIELD, STERLING UNDEFINED GAS POOL (STERLING FORMATION)

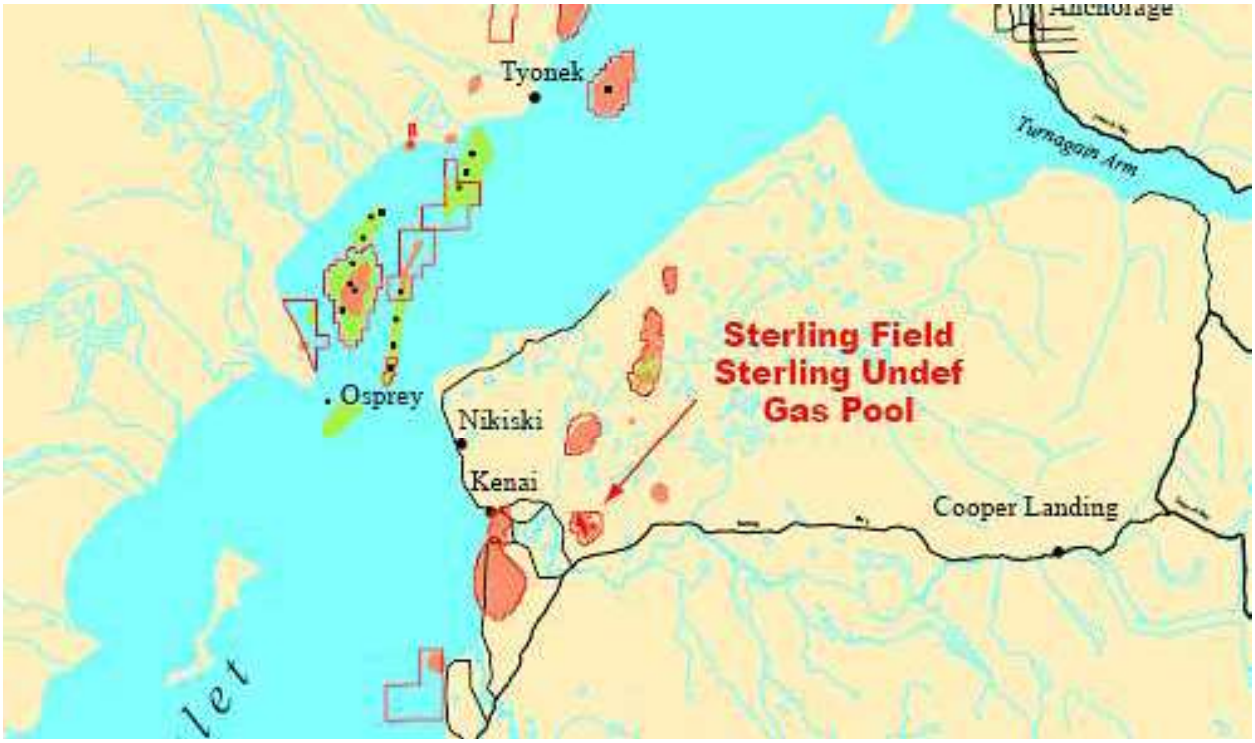
15.1 2009 Screening Context

The Sterling Field was evaluated as part of the 2009 TransCanada gas storage screening, including review of Sterling Formation gas pools within the Cook Inlet Basin. At the time of the screening, the Sterling undefined gas pool was considered in the context of mature production fields with existing infrastructure but did not rank among the highest-priority candidates for gas storage development due to limited production history and field-level constraints.

The 2009 screening further noted the presence of a gas-water contact within the Sterling Formation interval and inferred bottom-water or aquifer influence, which contributed to very low observed deliverability and increasing water-gas ratios late in the production life of the field. Based on these characteristics, the Sterling Field gas pool was considered non-prospective for underground gas storage development despite existing infrastructure.

Figure 15-1 shows the location and areal extent of the Sterling Field Sterling undefined gas pool as depicted in the Phase 2 TransCanada screening.

Figure 15-1 Sterling Field – Sterling Undefined Gas Pool (Sterling Formation)



Note: Location and areal extent of the Sterling undefined gas pool as depicted in the Phase 2 TransCanada gas storage screening.

Source: Campbell (2009b).

15.2 Ownership and Operations

Ownership of the Sterling Field has changed since completion of the 2009 TransCanada study. Hilcorp Alaska LLC (Hilcorp) acquired the former Marathon Cook Inlet assets in 2012 and is currently the unit operator. Since acquisition, Hilcorp has maintained control of the field while periodically reassessing development opportunities within the Sterling Unit.

15.3 Current Production Status

As of 2025, the Sterling Field is classified as shut in. No gas production was reported from the Sterling undefined gas pool during June 2025, and no producing wells remain in the pool. Available well data indicate that the sole well historically associated with the Sterling undefined gas pool (Sterling Unit 43-09X) was plugged and abandoned in May 2025, confirming the field's current non-producing status.

15.4 Well Production Summary

Table 15-1 summarizes the current status of the Sterling Unit 43-09X well, which represents the only well historically completed in the Sterling undefined gas pool based on available data. The table is provided to document the pool's current operational status relative to its historical screening for gas storage potential.

15.5 2025 Update

The AOGCC lists one well, SU 32-09, with an active gas completion and all others as plugged and abandoned. Sterling Field is currently plugged & abandoned , Hilcorp has initiated new leasing and permitting activity within the Sterling Unit. In 2024, Hilcorp acquired two leases during the statewide lease sale and subsequently submitted three drilling permit applications for wells identified as Sterling Unit 32-16, Sterling Unit 43-10RD, and Sterling Unit 43-10 targeting Sterling, Beluga, and Tyonek formations

These permitting actions indicate renewed development interest within the Sterling Unit despite the absence of current production.

Hilcorp's renewed interest in the Sterling Field, combined with ongoing leasing and permitting activity, suggests that future operational use remains under evaluation and has not yet been defined with respect to potential gas storage development.

To date over 3.8 BCF of gas and 142,000 bbls of water have been produced from the Sterling undefined gas pool.

Table 15-1 Sterling Field – Sterling Undefined Gas Pool Well Production Status

Well Name	Operator	Field	Pools	Current Class	Current Status
Sterling Unit 41-15RD	Hilcorp Alaska, LLC	STERLING	Lower Bel/Tyonek Undef Gas, Tyonek Undefined Gas	Development	Plugged & Abandoned
Sterling Unit 43-09X	Hilcorp Alaska, LLC	STERLING	Sterling Undefined Gas	Development	Plugged & Abandoned
Sterling Unit 32-09	Hilcorp Alaska, LLC	STERLING	Sterling Undefined Gas, Upper Beluga Undefined Gas	Development	Gas well, single completion
Sterling Unit 41-15	Marathon Oil Company	STERLING	Beluga Undefined Gas, Tyonek Undefined Gas	Development	Plugged & Abandoned
Sterling Unit 43-09	Hilcorp Alaska, LLC	STERLING	Undefined Wdsp, Sterling Undefined Gas	Service	Plugged & Abandoned
Sterling Unit 23-15	Hilcorp Alaska, LLC	STERLING	Sterling Undefined Gas	Development	Plugged & Abandoned

Notes:

1. Production data reflect reported May 2025 volumes.
2. The listed well is plugged and abandoned; zero production reflects permanent cessation of operations rather than temporary shut-in status.
3. Table data are provided to document current operational status and recent production activity and are not intended to represent a reassessment of gas storage suitability or reservoir performance.

Key:

bbl = barrel

Mcf = thousand cubic feet of gas

SI = shut-in

Source: Table compiled by ASRC Energy Services using publicly available well and production data current as of June 2025. Historical screening context referenced in associated text is based on the TransCanada gas storage prospectivity assessment (Campbell 2009a–c).

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16.0 CONCLUSION

This review evaluated the current ownership, development status, and operational context of gas pools within the Cook Inlet Basin that were originally screened by TransCanada in 2009 for potential underground gas storage development. The evaluation incorporated publicly available production data through June 2025 and considered subsequent exploration, development, and ownership changes that have occurred since completion of the original screening.

Results of the review indicate that the majority of gas pools identified as prospective candidates in the 2009 TransCanada assessment are no longer available for third-party gas storage development. Since the time of the original screening, most candidate reservoirs have been incorporated into active production programs, converted to operational gas storage facilities, or are otherwise operationally committed within fields owned and actively managed by Hilcorp Alaska LLC.

Several fields – including Beaver Creek, Cannery Loop, Kenai, Swanson River, and Ivan River – remain under active development and continue to support a combination of gas production and storage operations. In these fields, reservoir intervals that were previously identified as technically suitable for storage are now constrained by current ownership, production priorities, or existing storage use. As a result, the practical availability of these reservoirs for new, independent gas storage development is limited in practice, despite favorable geologic characteristics identified in earlier screening efforts.

Among the evaluated assets, the Kenai Loop Field Upper Tyonek gas pool remains the only identified candidate that is not owned or operated by Hilcorp and is therefore not subject to the same operational constraints affecting other Cook Inlet fields. The Kenai Loop Field was discovered after completion of the 2009 TransCanada screening and has not been previously evaluated within that framework. Current production activity and ownership structure indicate that this pool may warrant further technical review, should gas storage development be pursued.

This report does not reevaluate subsurface reservoir performance, injectivity, deliverability, or storage design parameters. Rather, it provides an updated planning-level assessment of availability and relevance based on current operational conditions. Any future evaluation of gas storage feasibility at Kenai Loop or other candidate reservoirs would require detailed geologic, reservoir engineering, and regulatory analysis beyond the scope of this review.

Overall, the findings underscore the narrowing set of opportunities for new underground gas storage development in the Cook Inlet Basin and highlight the importance of early identification and preservation of suitable reservoirs before they are committed to long-term production or storage operations.

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17.0 REFERENCES

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