

Alaska State Legislature


Senator Cathy Giessel
Senate Majority Leader
Senate District E
907-465-4843



120 4th Street
Alaska State Capitol,
Room 121
Juneau, AK 99801

MEMORANDUM

TO: Rep. Carolyn Hall, Co-Chair, House Labor & Commerce Committee
Rep. Zack Fields, Co-Chair, House Labor & Commerce Committee

FROM: Senator Cathy Giessel, Majority Leader 

DATE: April 7, 2026

Subject: Senate Bill 180 Hearing Request (LNG IMPORT FACILITIES)

I respectfully request that **Senate Bill 180: LNG Import Facilities** be scheduled before the House Labor & Commerce Committee at your earliest convenience.

Attached you will find:

1. SB 180 Sponsor Statement, Version A
2. SB 180, Version I
3. SB 180 Sectional Analysis, Version I
4. SB 180 Fiscal Note- DCCED
5. SB 180 Support Document – Summary of RCAs Position in Authority over Imported Natural Gas
6. SB 180 Support Document – RCA Notice of Utility Tariff Filing
7. SB 180 Support Document – RCA Order U-25-004.5 4.22.25
8. SB 180 Support Document – RCA Response to ENSTAR Docket 3.6.26
9. SB 180 Support Document – RCA Special Public Meeting 01.15.26
10. SB 180 Support Document – Summary Document re RCA U-25-004

For more information, please feel free to contact my staff, Paige Brown at (907)465-6308 or paige.brown@akleg.gov. Thank you for your consideration.

Sen.Cathy.Giessel@akleg.gov

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120 4th Street
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Juneau, AK 99801

Senate Bill 180 (version A)

Sponsor Statement

*"An Act relating to the regulation of liquefied natural gas import facilities by the
Regulatory Commission of Alaska."*

Senate Bill 180 would repeal AS 42.05.711(v). The repeal returns the Regulatory Commission of Alaska authority to regulate the import of liquefied natural gas.

This bill is needed to protect consumers and guarantee the lowest energy rates for rate payers as Alaska looks to import liquefied natural gas.

The legislation does not expand RCA jurisdiction to a privately held import terminal. It merely lifts the cloud on RCA jurisdiction over certificated utilities' gas supply contracts from an LNG import terminal. This will treat those gas supply contracts the same as a supply contracts from a Cook Inlet producer.

Prior to the previous Legislature, the Regulatory Commission of Alaska had the authority to regulate the import of liquefied natural gas. This bill would simply give that authority back to the Commission.

CS FOR SENATE BILL NO. 180(L&C)

IN THE LEGISLATURE OF THE STATE OF ALASKA

THIRTY-FOURTH LEGISLATURE - SECOND SESSION

BY THE SENATE LABOR AND COMMERCE COMMITTEE

Offered: 3/23/26

Referred: Rules

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the regulation of liquefied natural gas import facilities by the**
2 **Regulatory Commission of Alaska; and providing for an effective date."**

3 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

4 * **Section 1.** AS 42.05.711(v) is repealed.

5 * **Sec. 2.** This Act takes effect immediately under AS 01.10.070(c).

Alaska State Legislature

Senator Cathy Giessel
Senate Majority Leader
Senate District E
907-465-4843



120 4th Street
Alaska State Capitol,
Room 121
Juneau, AK 99801

Senate Bill 180 (version I)

Sectional Analysis

Section 1: Repeals AS 42.05.711(v)

AS 42.05.711(v) a liquefied natural gas import facility under the jurisdiction of the Federal Energy Regulatory Commission is exempt from this chapter.

Section 2: Immediate Effective Date

Fiscal Note

State of Alaska
2026 Legislative Session

Bill Version: SB 180
Fiscal Note Number: _____
() Publish Date: _____

Identifier: SB180-DCCED-RCA-01-23-26
Title: LNG IMPORT FACILITIES
Sponsor: RESOURCES
Requester: (S) RESOURCES

Department: Department of Commerce, Community and
Economic Development
Appropriation: Regulatory Commission of Alaska
Allocation: Regulatory Commission of Alaska
OMB Component Number: 2417

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2027 Appropriation Requested	Included in Governor's FY2027 Request	Out-Year Cost Estimates					
			FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits								
Miscellaneous								
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None								
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time								
Part-time								
Temporary								

Change in Revenues

None								
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimated SUPPLEMENTAL (FY2026) cost: 0.0 *(separate supplemental appropriation required)*

Estimated CAPITAL (FY2027) cost: 0.0 *(separate capital appropriation required)*

Does the bill create or modify a new fund or account? No
(Supplemental/Capital/New Fund - discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No
If yes, by what date are the regulations to be adopted, amended or repealed? N/A

Why this fiscal note differs from previous version/comments:

Not applicable, initial version.

Prepared By: John M. Espindola, Chair
Division: Regulatory Commission of Alaska
Approved By: Hannah Lager, Administrative Services Director
Agency: Commerce, Community, and Economic Development

Phone: (907)276-6222
Date: 01/23/2026
Date: 01/23/26

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2026 LEGISLATIVE SESSION

BILL NO. SB 180

Analysis

Senate Bill 180 repeals AS 42.05.711(v), an exemption provision enacted by the 33rd Legislature to explicitly provide that a liquified natural gas facility under the jurisdiction of the Federal Energy Regulatory Commission is exempt from AS 42.05.

AS 42.05 is titled the *Alaska Public Utilities Regulatory Act* and addresses the regulatory authority of the Regulatory Commission of Alaska (RCA). The repeal of AS 42.05.711(v) would eliminate any uncertainty regarding the RCA's jurisdiction over the review of gas supply agreements or terminal use agreements for public utilities using the services of a liquified natural gas import facility.

The Regulatory Commission of Alaska expects to implement the provisions of this legislation with existing resources.

Summary of RCA's Position on Authority Over Imported Natural Gas from Jan 28, 2025 Meeting

- **Statutory jurisdiction over public utilities:**

The RCA explains that its regulatory authority extends to public utilities operating in Alaska, regardless of whether the natural gas they distribute is produced in-state or imported. If imported gas is sold or transported by a regulated utility to Alaska consumers, that activity falls within RCA jurisdiction.

- **Focus on service and rates, not the physical act of importation:**

The RCA emphasizes that it does not regulate the *act of importing* natural gas itself. Instead, its authority applies to the **rates, terms, conditions, and reliability of utility service** once that gas is offered for sale or distribution by a regulated utility in Alaska.

- **Oversight of contracts involving imported gas:**

When a regulated utility enters into contracts for the supply of imported natural gas, the RCA asserts authority to review those contracts to ensure they are **just, reasonable, and in the public interest**, particularly as they affect customer rates and service obligations.

- **Consumer protection role:**

The RCA frames its authority as necessary to protect Alaska consumers from unreasonable costs, supply risks, or unfair practices that could arise from reliance on imported natural gas, especially where utilities seek cost recovery through regulated rates.

- **No expansion of authority claimed:**

The Commission states that oversight of imported gas does not represent an expansion of its powers; rather, it is a **continuation of existing regulatory responsibilities** applied to a changing supply source.

- **Jurisdiction triggered by utility status, not fuel origin:**

The RCA underscores that whether gas is imported is legally irrelevant to its authority. What matters is whether the entity selling or distributing the gas qualifies as a public utility under Alaska law.

REGULATORY COMMISSION OF ALASKA - Notice of Utility Tariff Filing

Notice of Utility Tariff Filing

The REGULATORY COMMISSION OF ALASKA (Commission) gives notice that Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA) filed TA58-733, requesting approval of 2023 Expansion Inception Rates for service provided under its 2023 Expansion Firm Storage Service (FSS) Agreement and seeking to revise its rules to differentiate between Initial Capacity customers and the Expansion Customer.

In TA55-733, the Commission approved a form 2023 Expansion FSS Agreement between CINGSA and ENSTAR Natural Gas Company, LLC and required CINGSA to file proposed inception rates based on actual capital expenditures at least 45 days before providing expansion service under the agreement. With TA58-733, CINGSA proposes inception rates. In addition, CINGSA requests the rates be made effective immediately, on an interim and refundable basis, and proposes to update the inception rates following its first full calendar year of operations of the 2023 Expansion Project. A comparison of the Initial Capacity and 2023 Expansion rates is shown in the table below.

	Initial Capacity Tariff Rate	2023 Expansion Tariff Rate
FSS Reservation Rate	\$5.0288/Mcf	\$6.2699/Mcf
FSS Capacity Rate	\$0.0686/Mcf	\$0.2038/Mcf
FSS Injection/Withdrawal Rate	\$0.0498/Mcf	\$0.0981/Mcf
Overrun Storage Service Rate	\$0.2152/Mcf	\$0.3043/Mcf
Excess Storage Service Charge	\$0.0686/Mcf	\$0.2038/Mcf
Interruptible Storage Service (ISS) Rate	\$0.2340/Mcf	\$0.4100/Mcf
ISS Injection/Withdrawal Rate	\$0.0498/Mcf	\$0.0981/Mcf

This notice does not contain all requested revisions, and the Commission may approve a rate or classification that varies from those proposed. You may obtain information about this filing by contacting Chelsea N. Guintu, Manager of Regulatory and Planning at CINGSA, P. O. Box 190989, Anchorage, AK 99519-0989; phone: (907) 334-7620. The complete filing is also available for inspection at the Commission's office at 701 West Eighth Avenue, Suite 300, Anchorage, AK 99501; phone: (907) 276-6222, or may be viewed on the Commission's website at <http://rca.alaska.gov> by typing "TA58-733" in the *Find a Matter* search box.

To comment on this filing, please file your comments by 5:00 p.m., December 10, 2024, at the Commission address given above or at its website:

<https://rca.alaska.gov/RCAWeb/WhatsNew/PublicNoticesComments.aspx>

Please reference TA58-733 and include a statement that you have filed a copy of the comments with CINGSA at its address given above. Individuals or groups of people with disabilities, who require special accommodations, auxiliary aids or service, or alternative communication formats, please contact Sam Vukasin at (907) 276-6222, toll-free at 1-800-390-2782, or TTY/Alaska Relay at 7-1-1 or 1-800-770-8973, or send a request via electronic mail to rca.mail@alaska.gov by December 3, 2024.

DATED at Anchorage, Alaska, this 26th day of November, 2024.

REGULATORY COMMISSION OF ALASKA

John M. Espindola
Chair

Attachments, History, Details

Attachments

None

Revision History

Created 11/26/2024 5:30:49 PM by lahenry

Details

Department:	Commerce, Community, and Economic Development
Category:	Public Notices
Sub-Category:	Pipeline/Utilities
Location(s):	Statewide
Project/Regulation #:	TA58-733
Publish Date:	11/26/2024
Archive Date:	12/10/2024
Events/Deadlines:	Public Notice Comment Deadline 12/10/2024 5:00pm

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
907-276-6222; TTY 1-800-770-8973

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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chair
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Tariff Revision Designated as)
TA350-4 Filed by ENSTAR NATURAL GAS)
COMPANY, LLC)

U-25-004

ORDER NO. 5

**ORDER CLOSING REGULATORY ASSET AUTHORIZED BY ORDER
U-22-090(2), APPROVING NEW REGULATORY ASSET, DENYING TA350-4,
FINDING MOTIONS FOR CONFIDENTIAL DISCOVERY ORDERS AND
MOTION FOR EXPEDITED CONSIDERATION MOOT, REQUIRING FILINGS,
VACATING REMAINING PROCEDURAL SCHEDULE AND HEARING,
AND APPOINTING ADMINISTRATIVE LAW JUDGE**

BY THE COMMISSION:

Summary

We close the regulatory asset authorized by Order U-22-090(2). We approve the creation of a new regulatory asset for certain future development costs incurred by ENSTAR Natural Gas Company, LLC (ENSTAR). We deny the tariff revision designated as TA350-4 filed by ENSTAR. We find the motions for confidential discovery orders filed by ENSTAR and the Office of the Attorney General, Regulatory Affairs and Public Advocacy Section (RAPA) and the motion for expedited consideration filed by RAPA moot. We require filings. We vacate the remaining procedural schedule and hearing for this proceeding. The chair appoints an administrative law judge.

Background

On January 28, 2025, ENSTAR filed a tariff revision designated as TA350-4. The filing proposes to revise ENSTAR's gas cost adjustment (GCA) surcharge to allow

1 ENSTAR is largely seeking to recover costs directly related to a FERC-regulated facility
2 that is outside of this Commission’s jurisdiction.⁷⁷

3 JLP/RSD argue that the Legislature’s intent to restrict Commission
4 jurisdiction by adopting AS 42.05.711(v) was shown when it expressly decided to remove
5 language stating “[f]or rate-making purposes, the commission shall consider the
6 investment of a public utility in a liquified natural gas import or export facility” from HB 50.
7 JLP/RSD assert this language appeared in the Senate Finance Committee draft of HB 50
8 but was subsequently amended to state, “For rate-making purposes, the commission
9 shall not consider the investment of a public utility in a liquified natural gas import or export
10 facility.”⁷⁸

11 As to Joint Development Agreement costs, JLP/RSD state that ENSTAR
12 has failed to provide any detail regarding what its obligations may be under such an
13 agreement and the agreement is clearly related to the development of the LNG import
14 facility, which is a non-jurisdictional project.⁷⁹

15 As to the Terminal Use Agreement and LNG Sales and Purchase
16 Agreement, JLP/RSD state that “ENSTAR apparently plans to purchase gas outside of
17 Alaska for import to the facility and to utilize the facility to regasify the LNG for use in
18 Alaska.” JLP/RSD state that this “activity constitutes interstate transportation of gas and
19 is squarely within FERC’s jurisdiction.”⁸⁰

20 As to any gas sales agreement, JLP/RSD state that “costs associated
21 exclusively with negotiating a gas sales agreement for the purchase of and use of gas
22 within Alaska may be properly recoverable to the extent they are prudently incurred.”
23 However, JLP/RSD state such costs are only recoverable after they have been incurred

24 _____
25 ⁷⁷JLP/RSD Reply at 5–7.

26 ⁷⁸JLP/RSD Opening Brief at 5–6.

⁷⁹JLP/RSD Reply at 7.

⁸⁰JLP/RSD Reply at 7.

1 as RAPA claims, we do not see a viable path to acquiring jurisdiction. Were we to do so,
2 we would violate AS 42.05.711(v). This subsection provides that “A liquified natural gas
3 import facility under the jurisdiction of the Federal Energy Regulatory Commission is
4 exempt from this chapter.”

5 This subsection was adopted via HB 50 in 2024. Not only does this
6 subsection’s express language appear to clearly bar our assumption of jurisdiction, but
7 the legislative history underlying its enactment reinforces this conclusion.¹²⁷ Therefore,
8 if we were to assert LNG facility oversight under the Hinshaw Amendment which RAPA
9 suggests is possible, we would be disregarding the jurisdictional side boards imposed on
10 us by the legislature. We decline to do so.¹²⁸

11 The second jurisdictional issue presented by the parties addresses whether
12 FERC or this Commission’s jurisdiction would attach to development costs identified in
13 TA350-4. RAPA claims these costs “are inextricably linked to their subject matter, an
14 LNG terminal.”¹²⁹ JLP/RSD make similar arguments.¹³⁰

15 We note initially that a different analysis applies when looking at
16 development costs under ENSTAR’s Scenario 1 compared to Scenario 2. Under
17 Scenario 1, if the LNG Project advances to construction, the only development costs
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20 ¹²⁷JLP/RSD Opening Brief at 5 & n.19 points to minutes and amendments
21 preceding the adoption of AS 42.05.711(v). Section 40 of Version T, SCS CSHB50, dated
22 May 10, 2024, had included a proposed amendment to AS 42.05.381 which would have
23 granted the Commission jurisdiction to “consider the investment of a public utility in a
24 liquified natural gas import facility as utility property, even if the liquified natural gas import
or export facility is exempt from regulation by the commission.” This subsection was
eliminated by Amendment 4, dated May 11, 2024. See JLP/RSD Opening Brief at
Exhibit 2.

25 ¹²⁸Because we do not have jurisdiction over an LNG import facility, we also lack
authority to assess whether a duplication of facilities, such as that announced by Harvest
Midstream, would be contrary to the public interest under AS 42.05.221(d).

26 ¹²⁹RAPA Opening Brief at 7.

¹³⁰JLP/RSD Reply at 5–11.

1 costs for prudence and reasonableness when they are presented in a rate case for our
2 review.¹³⁵

3 A third jurisdictional question arose in conjunction with ENSTAR's
4 description of gas supply and terminal use agreements that will be presented to us after
5 the LNG Project is viable. As ENSTAR argues:

6 FERC jurisdiction ends where the LNG Terminal connects to a state-regulated
7 pipeline. . . . [and it] does not extend to the purchase of LNG supply or the
8 purchase of the service from LNG importation and regasification facilities.
9 Instead, intrastate activities in Alaska by a[n] [LDC] local natural gas
10 transportation and distribution company are regulated by this Commission –
11 including interactions with an LNG Terminal regulated by FERC.¹³⁶

12 To illustrate this point, ENSTAR provides a useful analogy:

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15 ¹³⁵We were concerned at the prehearing conference held in this docket on
16 February 13, 2025, when ENSTAR's president emphatically stated ENSTAR would not
17 consider participating in or using an alternative LNG import facility project recently
18 announced. See Tr. 12-13:

19 [I]n 2024, I made the very, very clear statement to the group that there is no
20 world in which ENSTAR will participate in a project that has a Hilcorp-owned
21 entity as the importer of natural gas. . . . ENSTAR, as a natural gas utility, will
22 not be reliant upon an entity that provides Cook Inlet gas, Cook Inlet storage
23 and the importation of LNG, full stop. We cannot do that from a long-term
24 strategic perspective, from a planning perspective. That is way too much risk
25 for our customers I also believe that there's a massive benefit to the
26 ratepayer for participating in the same projects. Chugach has said that that is
not a competing project, they are 100 percent correct. It does not compete with
what we are looking to do in any way, shape or form because ENSTAR will
not participate in that project because of the reasons I've stated.

27 We emphasize that ENSTAR's decision to enter into an exclusivity agreement with
28 Glenfarne does not usurp or limit the scope of our prudence review authority. Thus, our
29 prudence review of development costs under either Scenario 1 or 2, as well as our review
30 of any gas supply or terminal use agreements, will likely include an assessment of
31 whether a prudent utility manager should have considered or selected a competing LNG
32 import facility option to meet ENSTAR's gas supply needs.

¹³⁶ENSTAR Opening Brief at 10–11.

1 Ultimately, these costs are no different from a Commission jurisdiction
2 standpoint than ENSTAR's costs to negotiate and enter into a gas sales
3 agreement with an unregulated (by the Commission) Cook Inlet gas producer.
4 Like an LNG import terminal, the Commission does not have jurisdiction over
5 the siting or construction of Cook Inlet producers' platforms and pipelines, but
6 it does have jurisdiction to regulate ENSTAR as a utility-offtaker of those
7 facilities. The import facility itself may not be regulated by this Commission,
8 but ENSTAR's interconnection with an LNG Terminal, and any necessary gas
9 purchase agreements or terminal use agreements, are all firmly within this
10 Commission's jurisdiction.¹³⁷

11 JLP/RSD dispute this. JLP/RSD claim because gas sales and terminal use
12 agreements stem from ENSTAR's plans to "purchase gas outside of Alaska for import to
13 the facility and to utilize the facility to regasify the LNG for use in Alaska," that "[t]his
14 activity constitutes interstate transportation of gas and is squarely within FERC's
15 jurisdiction."¹³⁸

16 We disagree.¹³⁹ We find ENSTAR's analogy to our current jurisdictional
17 boundaries for our review of Cook Inlet gas supply contracts useful. We also find case
18 law presented by Chugach persuasive on this issue. Both *Transcontinental Gas*¹⁴⁰ and

19 ¹³⁷ENSTAR Opening Brief at 12.

20 ¹³⁸JLP/RSD Reply at 7.

21 ¹³⁹We note that we do not have any gas supply or terminal use agreements before
22 us. Nor do we have specific facts to assess the contours of any such agreements.
23 Therefore, our opinion on this issue is generic and based only on the generalities
24 presented and is subject to modification to the extent any agreements brought before us
25 later warrant our doing so.

26 ¹⁴⁰190 FERC ¶ 61,048 at P. 36 (2025) ("[W]e reaffirm that oversight of LDC
procurement decisions is outside the Commission's jurisdiction and best left to state
regulators. Absent credible evidence of self-dealing, an attempt by the Commission to
look behind precedent agreements to independently review the decision-making of an
LDC might infringe upon the role of state regulators in determining the prudence of
expenditures by the utilities they regulate. Therefore, 'issues related to the utility's ability
to recover costs associated with its decision to subscribe for service on the [project]
involve matters to be determined by the [state regulator]; those concerns are beyond the
scope of the Commission's jurisdiction. Here, New Jersey has the authority to conduct a
prudence review to ascertain whether an LDC's capacity purchases and attendant costs
are just and reasonable and whether it is appropriate to pass those costs onto
customers.'").

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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: John M. Espindola, Chair
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Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Tariff Revision Designated as) U-25-004
TA350-4 Filed by ENSTAR NATURAL GAS)
COMPANY, LLC) ORDER NO. 5

**ORDER CLOSING REGULATORY ASSET AUTHORIZED BY ORDER
U-22-090(2), APPROVING NEW REGULATORY ASSET, DENYING TA350-4,
FINDING MOTIONS FOR CONFIDENTIAL DISCOVERY ORDERS AND
MOTION FOR EXPEDITED CONSIDERATION MOOT, REQUIRING FILINGS,
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BY THE COMMISSION:

Summary

We close the regulatory asset authorized by Order U-22-090(2). We approve the creation of a new regulatory asset for certain future development costs incurred by ENSTAR Natural Gas Company, LLC (ENSTAR). We deny the tariff revision designated as TA350-4 filed by ENSTAR. We find the motions for confidential discovery orders filed by ENSTAR and the Office of the Attorney General, Regulatory Affairs and Public Advocacy Section (RAPA) and the motion for expedited consideration filed by RAPA moot. We require filings. We vacate the remaining procedural schedule and hearing for this proceeding. The chair appoints an administrative law judge.

Background

On January 28, 2025, ENSTAR filed a tariff revision designated as TA350-4. The filing proposes to revise ENSTAR's gas cost adjustment (GCA) surcharge to allow

1 ENSTAR to recover amounts recorded in a previously approved regulatory asset.¹ In
2 support of its filing, ENSTAR filed the affidavit of John Sims, a redline version of the
3 proposed tariff changes, and a preliminary project timeline.²

4 We issued public notice of TA350-4 on January 30, 2025, with comments
5 due February 13, 2025. We received public comments from two individuals; Doyon,
6 Limited; and the Alaska Public Interest Research Group.³

7 With Order U-25-004(1), we suspended TA350-4 into this docket for
8 investigation, invited participation by the Attorney General (AG), and invited intervention
9 by interested persons. We issued questions to be addressed through written briefing by
10 ENSTAR; the AG, if he elected to participate; and any interested person who petitioned
11 to intervene and was ultimately granted intervenor status. We scheduled a prehearing
12 conference to expedite the orderly conduct and disposition of this docket through the
13 adoption of a procedural schedule and to establish a timeline for written briefing.⁴

14 RAPA elected to participate⁵ and we received petitions to intervene from
15 Chugach Electric Association, Inc. (Chugach), JL Properties, Inc. (JLP), RSD
16 Properties, LLC (RSD) (jointly, JLP/RSD), Homer Electric Association, Inc. (HEA),
17 Matanuska Electric Association, Inc. (MEA), and Golden Valley Electric Association, Inc.

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20 ¹Order U-22-090(2), *Order Granting Petition to Create Regulatory Asset, Requiring Reporting, and Closing Docket*, dated February 22, 2023 (Order U-22-090(2)).

21 ²TA350-4 at Attachment A, B, C, and D.

22 ³Comment by T. Barrett, filed February 4, 2025; Comment by J. Weiss, filed
23 February 4, 2025; Comment by A. Schutt on behalf of Doyon, Limited, filed
February 6, 2025; Comment by N. Kiley-Burgen and V. di Suvero on behalf of Alaska
Public Interest Research Group, filed February 13, 2025.

24 ⁴Order U-25-004(1), *Order Denying Waiver, Suspending Tariff Revision, Inviting Participation by the Attorney General and Intervention by Interested Persons, Issuing Questions, Scheduling Prehearing Conference, Addressing Timeline for Decision, Designating Commission Panel, and Appointing Administrative Law Judge*, dated February 4, 2025 (Order U-25-004(1)); Order U-25-004(2), *Order Issuing Additional Question*, dated February 6, 2025 (Order U-25-004(2)).

25 ⁵*Notice of Election to Participate*, filed February 4, 2025.

1 (GVEA).⁶ We held a prehearing conference on February 13, 2025, with ENSTAR, RAPA,
2 Chugach, JLP, RSD, HEA, MEA, and GVEA participating.⁷ At the prehearing conference,
3 the parties proposed and we adopted a procedural schedule and a written briefing
4 schedule for the issued questions.⁸ We granted each of the petitions to intervene filed in
5 this proceeding.⁹ All parties filed opening and reply briefs.¹⁰

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8 ⁶*Chugach Electric Association, Inc.'s Petition to Intervene*, filed February 11, 2025;
9 *Petition to Intervene of JL Properties, Inc.*, filed February 11, 2025; *Petition to Intervene*
10 *of RSD Properties, LLC.*, filed February 11, 2025; *Homer Electric Association Inc.'s*
11 *Petition to Intervene*, filed February 12, 2025; *Petition to Intervene of Matanuska Electric*
12 *Association, Inc.*, filed February 12, 2025; *Golden Valley Electric Association, Inc.'s*
13 *Petition to Intervene*, filed February 13, 2025.

14 ⁷Tr. 1–35.

15 Our regulation addressing intervention is found at 3 AAC 48.110. That regulation
16 requires that any person wishing to intervene in a docket file a petition to intervene and
17 provides any party to the docket with an opportunity to file an answer to the petition within
18 seven days under 3 AAC 48.110(e). At the time of the prehearing conference, RAPA
19 confirmed that it did not oppose any of the petitions to intervene. However, the petitions
20 to intervene were not ripe for our consideration as the time for ENSTAR to file an answer
21 had not yet expired. As a result, Chugach, JLP, RSD, HEA, MEA, and GVEA had not
22 been granted or denied intervenor status. Nonetheless, Chugach, JLP, RSD, HEA, MEA,
23 and GVEA were treated as intervenors during the prehearing conference for the limited
24 purpose of establishing a procedural schedule and written briefing schedule.

25 ⁸Order U-25-004(3), *Order Adopting Procedural Schedule and Establishing*
26 *Briefing Schedule*, dated February 18, 2025.

⁹Order U-25-004(4), *Order Granting Intervention*, dated February 27, 2025.

¹⁰*ENSTAR Brief in Response to Commission Orders U-25-004(1) and*
U-25-004(2), filed February 28, 2025 (ENSTAR Opening Brief); *Office of the Attorney*
General's Opening Brief, filed February 28, 2025 (RAPA Opening Brief); *Chugach Electric*
Association, Inc.'s Opening Brief, filed February 28, 2025 (Chugach Opening Brief);
HEA's Brief on Commission Questions, filed February 28, 2025 (HEA Opening Brief);
Golden Valley Electric Association, Inc.'s Opening Brief, filed February 28, 2025 (GVEA
Opening Brief); *Matanuska Electric Association, Inc.'s Opening Brief*, filed February 28,
2025 (MEA Opening Brief); *JL Properties, Inc.'s and RSD Properties, LLC's Joint Opening*
Brief, filed February 28, 2025 (JLP/RSD Opening Brief); *Golden Valley Electric*
Association, Inc.'s Responsive Briefing, filed March 10, 2025 (GVEA Reply); *Chugach*
Electric Association, Inc.'s Reply Brief, filed March 10, 2025 (Chugach Reply); *HEA's*
Limited Reply in Response to Briefing on Commission Questions, filed March 10, 2025
(HEA Reply); *Office of the Attorney General's Responsive Brief*, filed March 10, 2025
(RAPA Reply); *Responsive Brief of Matanuska Electric Association, Inc.*, filed
March 10, 2025 (MEA Reply); *ENSTAR Natural Gas Company, LLC's Reply Brief*, filed
March 10, 2025 (ENSTAR Reply); *JL Properties, Inc.'s and RSD Properties, LLC's Joint*
Reply Brief, filed March 10, 2025 (JLP/RSD Reply).

1 On March 28, 2025, ENSTAR and RAPA filed competing motions for entry
2 of orders addressing confidential discovery material.¹¹ RAPA also filed a motion for
3 expedited consideration.¹² Chugach filed a response to both motions, opposing
4 ENSTAR's proposed order addressing confidential discovery material and non-opposing
5 the order proposed by RAPA.¹³ ENSTAR filed an opposition to RAPA's proposed
6 confidential discovery material order¹⁴ and a reply to Chugach's opposition.¹⁵

7 Discussion

8 In TA350-4, ENSTAR raises matters of first impression for us. The matters
9 present issues of law, policy, and undisputed fact. Therefore, we issued questions and
10 asked the parties to file both simultaneous opening and reply briefs. All parties responded
11 with thorough and in-depth briefing. After reviewing the briefing and TA350-4 itself, we
12 reach a final decision and do not require an evidentiary hearing, thus we vacate the
13 remaining procedural schedule and the hearing.

14 Regulatory Asset

15 On November 10, 2022, in Docket U-22-090, ENSTAR filed a petition to
16 create a regulatory asset to accumulate and defer the costs associated with studying and
17 securing long-term gas supplies for the Alaska Railbelt.¹⁶ In its Petition, ENSTAR stated

18 ¹¹*Office of the Attorney General's Motion for Entry of Proposed Order Governing*
19 *Confidential Discovery Material*, filed March 28, 2025; *Motion to Adopt Confidential*
20 *Discovery Material Order*, filed March 28, 2025, by ENSTAR.

21 ¹²*Office of the Attorney General's Motion for Expedited Consideration of Motion for*
22 *Entry of Proposed Order Governing Confidential Discovery Materials*, filed March 28,
23 2025.

24 ¹³*Chugach Electric Association, Inc.'s Position on Proposed Confidential*
25 *Discovery Orders*, filed April 2, 2025.

26 ¹⁴*ENSTAR's Opposition to the Office of the Attorney General's Motion for Entry of*
Proposed Order Governing Confidential Discovery Material, filed April 7, 2025.

¹⁵*ENSTAR's Reply in Support of Motion to Adopt Confidential Discovery Material*
Order, filed April 10, 2025.

¹⁶*ENSTAR Natural Gas Company's Petition for Approval to Create a Regulatory*
Asset for the Accumulation and Deferral [sic] of Costs Associated with Studying and
Securing Long Term Gas Supplies for the Alaska Railbelt, filed November 10, 2022
(Petition), in Docket U-22-090.

1 that it “intends to seek recovery of the amount not allocated to future capital projects or
2 reimbursed by a third party through a future rate proceeding.”¹⁷ In Order U-22-090(2),
3 we granted ENSTAR’s Petition to create a regulatory asset. In doing so, we reiterated
4 that we “continue a strong preference to not create regulatory assets, especially ones for
5 which we do not know, or even have an estimate of, the final total.”¹⁸

6 We were precise in our language when granting ENSTAR’s Petition. We
7 stated:

8 [W]e grant ENSTAR authority to defer all necessary and prudent third-party
9 costs incurred during its participation in the multiparty working group for
10 studying and securing long-term gas supplies in the Cook Inlet. Our approval
11 does not include amounts allocated to future capital projects or reimbursed by
12 third parties. Our decision does not shift ENSTAR’s evidentiary burden
regarding the necessity and prudence of costs, carrying costs, or appropriate
amortization periods. We will investigate these and any other issues required
at the time of ENSTAR’s request to include these costs in the calculation of
rates.¹⁹

13 As we required, ENSTAR routinely files a report on the balance of
14 consulting and other costs accumulated in the approved regulatory asset with its Second
15 and Fourth Quarterly Gas Cost Balance Account (GCBA) Reports.

16 During a presentation at our January 15, 2025, special public meeting,
17 ENSTAR’s president announced that on December 17, 2024, ENSTAR had entered into
18 an exclusivity agreement with Glenfarne Group, LLC (Glenfarne)²⁰ to work towards the
19 development of a liquefied natural gas (LNG) importation and regasification terminal (LNG
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24 ¹⁷Petition at 6.

25 ¹⁸Order U-22-090(2) at 6.

26 ¹⁹Order U-22-090(2) at 6–7.

²⁰In this order we use “Glenfarne” to refer to Glenfarne Group, LLC and its affiliates,
including Glenfarne Energy Transition, LLC.

1 Project).²¹ ENSTAR states that the LNG Project “may include an LNG marine and import
2 terminal, an onshore LNG storage tank, and/or a regasification facility.”²²

3 TA350-4

4 In TA350-4, ENSTAR seeks to recover \$4.6 million in costs accumulated in
5 the regulatory asset allowed by Order U-22-090(2), plus carrying costs. ENSTAR
6 proposes to apply carrying costs to its \$4.6 million accumulated regulatory asset as of
7 December 31, 2024. To calculate these costs, ENSTAR will apply an annual rate of
8 5.34% to the regulatory asset balance, compounded monthly through March 2025. This
9 reflects the long-term interest rate that ENSTAR received on its 5-year note, as filed with
10 the Commission in ENSTAR’s most recent Annual Operating Report. These costs will be
11 collected through ENSTAR’s annual GCA surcharge mechanism by creating a new cost
12 element in its GCA methodology and passing the costs through its GCBA.²³

13 ENSTAR explains that future new costs identified in TA350-4 are for the
14 development phase of the LNG Project. They will include commercial, engineering, and
15 permitting activities. ENSTAR divides the proposed development phase costs into two
16 categories: ENSTAR Costs and Developer Costs.²⁴ ENSTAR further categorizes those
17 costs as project agreements, engineering, and permitting costs.²⁵

18 ENSTAR anticipates spending approximately \$10 million on its project
19 development expenditures. This amount includes \$4.6 million ENSTAR already
20 accumulated in its regulatory asset account established under Order U-22-090(2).²⁶

21 ²¹January 15, 2025, Special Public Meeting Tr. 18–25; Presentation at 6. ENSTAR
22 further noticed its exclusivity agreement with Glenfarne in its *2024 Fourth Quarter Gas
23 Cost Balance Account Report and Compliance with U-22-090(2) Reporting
24 Requirements*, filed January 15, 2025. This is reiterated in TA350-4 at 2; Attachment A,
25 Affidavit of John D. Sims at 4.

24 ²²ENSTAR Opening Brief at 6.

25 ²³TA350-4 at 3–4.

26 ²⁴These costs are described in TA350-4 at 3–6.

²⁵TA350-4 at 4–6.

²⁶TA350-4 at 3.

1 Going forward, ENSTAR estimates incurring \$5 million each year during the Development
2 Phase.²⁷ However, the timeline attached to TA350-4 only shows an estimated \$2 million
3 in ENSTAR Costs for 2025 and \$3.4 million for 2026.²⁸ ENSTAR's project agreements
4 costs will be comprised of legal fees, commercial and technical industry consulting, due
5 diligence necessary to vet agreements, and incremental costs associated with regulatory
6 filings. ENSTAR's anticipated engineering costs are to finalize commercial use
7 agreements, project financial security agreements, land agreements, and/or LNG sales
8 and purchase agreements. ENSTAR states it may also need to provide necessary
9 financial security or guarantees and engineering and project management oversight.
10 ENSTAR's permitting costs include legal and technical expenses to support permitting
11 activities, responses to regulators or customers, legal and consulting fees for final
12 approval, intermediate reporting requirements, and preparing for implementation and
13 integration of LNG into the gas system.²⁹

14 The second development cost category includes necessary external and
15 internal costs incurred by the developer. ENSTAR states the Developer Costs will only
16 be recovered through the GCA if the LNG Project is suspended, terminated, or
17 cancelled.³⁰ If the LNG Project is built, those Developer Costs will instead be included
18 as capital costs in the new LNG Project.³¹ The owners of the LNG Project will then
19 recover those capital costs through supply purchase or import terminal use agreements
20 once the LNG Project is operational.

21 ENSTAR predicts that Developer Costs will be between \$43 and \$48
22 million. If the LNG Project is suspended, terminated, or cancelled late in development,
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24 ²⁷TA350-4 at 3–4.

25 ²⁸TA350-4 at Attachment D.

26 ²⁹TA350-4 at 5–6.

³⁰ENSTAR refers to this as “Scenario 2.” TA350-4 at 4.

³¹ENSTAR refers to this as “Scenario 1.” TA350-4 at 4.

1 “ENSTAR will be obligated to promptly reimburse Developer Costs in a lump sum
2 payment,” resulting in a significant increase to the GCA surcharge.³²

3 In Orders U-25-004(1) and U-25-004(2) we issued seven questions to the
4 parties for briefing:

- 5 1. Other than costs authorized by Order U-22-090(2), explain how the
6 Commission has jurisdiction to consider all of the costs ENSTAR proposes for
7 recovery in TA350-4 given the Federal Energy Regulatory Commission’s
8 exclusive jurisdiction over the “siting, construction, expansion, and operation”
9 of a liquified natural gas (LNG) facility under 15 USC Section 717b(e)(1), or
10 other provisions of 15 USC Section 717, and given the exclusion of an LNG
11 import facility from Commission jurisdiction under AS 42.05.711(v).³³
- 12 2. In Order U-22-090(2), we stated we were granting ENSTAR’s request to “defer
13 all necessary and prudent third-party costs incurred during its participation in
14 the multi-party working group for studying and securing long term gas supplies
15 in the Cook Inlet” in a regulatory asset. See Order U-22-090(2) at 6. ENSTAR
16 states that as of December 17, 2024, it is no longer studying gas supply
17 options but has instead entered into an exclusive arrangement with Glenfarne
18 to import LNG to meet gas supply shortfalls. Explain why the regulatory asset
19 allowed by Order U-22-090(2) should not be terminated from including any
20 further third-party costs as of December 17, 2024, since the reason upon which
21 Order U-22-090(2)’s permission for regulatory asset treatment was based
22 (identifying a path forward) no longer appears to exist.
- 23 3. Explain why it is proper for ENSTAR’s ratepayers to assume all cost
24 obligations for all risk associated with the described LNG Project’s
25 development given that ENSTAR’s return on equity is designed, at least in
26 part, to compensate it for its business risk.
- 27 4. In Order U-22-090(2), the Commission stated it would investigate the prudence
28 of costs, carrying costs, appropriate amortization period, and other issues
29 related to the regulatory asset at the time ENSTAR requests to include these
30 costs in rates. The Commission further required ENSTAR to make compliance
31 filings until the recovery of the regulatory asset was approved in a ratemaking
32 proceeding. It is the Commission’s ratemaking practice is to review regulatory
33 asset costs for inclusion in rates in a rate case, not through a Cost of Power
34 Adjustment (COPA) or a GCA. See e.g. Order U-19-101(5) at 8. Since the
35 Commission intended its review of the regulatory asset authorized by Order
36 U-22-090(2) to occur in a rate case proceeding where the prudence and
37 reasonableness of the costs could be reviewed, why is it proper to instead
38 allow ENSTAR to seek cost recovery through its GCA?

32TA350-4 at 4. ENSTAR estimates this impact at approximately \$15 per month
to residential customers.

33AS 42.05.711(w) was relettered by the Revisor as AS 42.05.711(v). In this order,
we have therefore replaced all references to AS 42.05.711(w) in our past orders and the
parties’ briefing with AS 42.05.711(v). See 2024 Revisors notes to AS 42.05.711.

- 1 5. Identify any Commission precedent where the Commission has allowed a
2 regulated utility to recover previously approved regulatory asset costs through
3 a COPA or a GCA.
4 6. Explain how ENSTAR's request to recover its regulatory asset costs through
5 its GCA is consistent with 3 AAC 52.505(a).
6 7. ENSTAR's TA350-4 at 4 requests inclusion of "Developer Costs" in the GCA
7 under two scenarios. Under Scenario 2, estimated at between \$43 and \$48
8 million, ENSTAR requests full cost recovery via its GCA in the event the project
9 "is suspended, terminated or otherwise cancelled." Explain how inclusion of
10 these costs in consumer rates would not be barred by AS 42.05.441(b) since
11 the costs incurred would not result in used and useful plant.

12 As previously stated, ENSTAR, RAPA, Chugach, HEA, MEA, and GVEA
13 each submitted their own opening and reply briefs, while JLP and RSD submitted theirs
14 jointly. The following is a summary of the parties' briefing.

15 Briefs

16 ENSTAR

17 In response to Question 1, ENSTAR argues that the Federal Energy
18 Regulatory Commission (FERC) jurisdiction does not extend to Natural Gas Act (NGA)
19 exempt intrastate pipeline and local distribution companies (LDCs), such as ENSTAR.
20 ENSTAR also states that 15 U.S.C. § 717(b) explicitly indicates that the NGA and federal
21 preclusion under the NGA do not apply to the intrastate sale and transport of natural
22 gas.³⁴ ENSTAR differentiates the costs at issue in TA350-4 as related to securing a gas
23 supply and formalizing a commercial relationship with the import facility and LNG
24 suppliers which falls within our authority, unlike the construction or operation of the facility
25 which would be within FERC's exclusive jurisdiction.³⁵

26 As an analogy, ENSTAR notes we have jurisdiction to regulate ENSTAR as
a utility-offtaker of Cook Inlet producers' platforms and pipelines. Likewise, ENSTAR
asserts that although the LNG Project may not be regulated by us, ENSTAR's

³⁴ENSTAR Opening Brief at 9.

³⁵ENSTAR Opening Brief at 12; ENSTAR Reply at 7-8.

1 interconnection with, and any necessary gas purchase agreements or terminal use
2 agreements, are all within our jurisdiction.³⁶

3 ENSTAR further argues that principles of statutory interpretation support
4 our jurisdiction over TA350-4. ENSTAR asserts that the language in AS 42.05.711(v)
5 plainly exempts a FERC-regulated LNG facility from our jurisdiction, but it does not
6 contain any language that precludes our jurisdiction over the costs incurred by an LDC to
7 interconnect with a LNG import facility, or over utility costs stemming from gas sales
8 agreements and terminal use agreements used to take natural gas from the facility.³⁷

9 ENSTAR states it will incur costs associated with securing LNG Project
10 agreements, as well as costs during the engineering and permitting phases of the
11 Project’s development. It claims all these development activities “are solidly within the
12 jurisdiction of the Commission.”³⁸

13 In response to Question 2, ENSTAR argues that although it signed an
14 exclusivity agreement with Glenfarne on December 17, 2024, it has not yet secured long-
15 term gas supplies and the reasoning behind Order U-22-090(2) still applies. ENSTAR
16 states that it committed to negotiate exclusively with Glenfarne to advance the LNG
17 Project and required respective agreements. It has not reached a final investment
18 decision and there is no completed project in place that secures long-term gas supplies
19 for the Cook Inlet.³⁹

20 In response to Question 3, ENSTAR states that it does not earn a return on
21 its cost of purchased gas which includes a cost of gas supply, pipeline transportation, and
22 gas storage service, implying any linkage of its costs to secure LNG supplies to its return
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25 ³⁶ENSTAR Opening Brief at 12.

26 ³⁷ENSTAR Reply at 5–6.

³⁸ENSTAR Opening Brief at 12–13.

³⁹ENSTAR Opening Brief at 15; ENSTAR Reply at 10–11.

1 on equity (ROE) would be illusory.⁴⁰ ENSTAR also argues that in its previous rate case,
2 we found that the regulatory asset created by Order U-22-090(2) offset some of
3 ENSTAR’s risk. ENSTAR states that we should not, on the one hand, decline to include
4 gas supply risk as a risk factor in determining ENSTAR’s ROE because of the regulatory
5 asset, and then use ENSTAR’s ROE as grounds to deny recovery of legitimate costs
6 incurred to secure long-term gas supplies for Southcentral Alaska.⁴¹

7 In response to Question 4, ENSTAR argues that in Order U-22-090(2) we
8 referenced “calculation of rates” and “ratemaking procedure” for the regulatory asset and
9 we did not order ENSTAR to propose recovery of its regulatory asset costs through a rate
10 case.⁴² ENSTAR contrasts this with our language in Order U-19-101(5), which explicitly
11 stated that the “amortization period [for ENSTAR’s regulatory asset to recover
12 extraordinary Earthquake costs] will be determined in ENSTAR’s next rate case.”⁴³

13 ENSTAR states that it is committed to providing complete transparency into
14 its costs. It claims its GCBA and GCA filings provide significant information for a prudence
15 review warranting approval of the GCA recovery mechanism requested in TA350-4.
16 ENSTAR argues that opposition brief arguments to this recovery mechanism ignore the
17 substantial amount of information that ENSTAR has committed to file in support of its
18 costs and the process we follow to investigate ENSTAR’s quarterly GCBA filings and
19 annual GCA filings. ENSTAR states that our Staff undertakes an extensive review of its
20 GCBA and GCA filings and calculations and it is required to answer questions from
21 Commission Staff on issues that require clarification and revise its calculations if
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24 ⁴⁰ENSTAR Opening Brief at 16.

25 ⁴¹ENSTAR Opening Brief at 16-17; ENSTAR Reply at 14-15.

26 ⁴²ENSTAR Opening Brief at 18.

⁴³ENSTAR Opening Brief at 18 (citing Order U-19-101(5), *Order Granting Petition to Create Regulatory Asset, Redesignating Commission Panel, and Closing Docket*, dated October 20, 2020, at 8, corrected by Errata Notice, dated October 22, 2020).

1 necessary. ENSTAR states that the GCA is a tariff filing that is subject to possible
2 suspension if we determine that we need additional time to review it.⁴⁴

3 In response to Question 5, ENSTAR states that GCA recovery is not
4 precluded by Commission precedent. ENSTAR further states that no party was able to
5 identify a proceeding that precluded such recovery where the utility met the regulatory
6 criteria in 3 AAC 52.502(a).⁴⁵

7 ENSTAR also cites two prior orders as analogous support for its request.
8 ENSTAR first cites Order U-86-008(6), where the Alaska Public Utilities Commission
9 ruled that ENSTAR could recover royalty settlement agreement costs relating to natural
10 gas purchased under an approved gas supply contract via a per-Mcf surcharge.⁴⁶
11 ENSTAR says the Commission chose not to authorize recovery via ENSTAR's GCA
12 because at that time the GCA provision provided for the collection of interest, which is no
13 longer the case.⁴⁷

14 ENSTAR also cites Orders U-01-152(4)⁴⁸ and U-01-152(5),⁴⁹ where we
15 authorized ENSTAR to defer and recover legal and consulting expenses incurred while
16 obtaining approval of a gas sales agreement as a surcharge. ENSTAR states that we
17 denied recovery via ENSTAR's GCA for the same reason as we did in Order U-86-008(6):

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19 ⁴⁴ENSTAR Reply at 18.

20 ⁴⁵ENSTAR Reply at 19.

21 ⁴⁶ENSTAR Opening Brief at 20 (citing Order U-86-008(6), *Order Allowing Flow-*
22 *Through of Royalty Gas Settlement and Associated Costs Over a Four-Year Period*
Without Interest, dated May 9, 1986, as corrected by Errata Notice, dated May 13, 1986
(Order U-86-008(6)).

23 ⁴⁷ENSTAR Opening Brief at 20.

24 ⁴⁸ENSTAR Opening Brief at 20 (citing Order U-01-152(4), *Order Denying Request*
for FAS 71 Treatment; Denying Request to Recover Legal and Consulting Expenses
Through Gas Cost Adjustment; Requiring Filing; Approving Tariff Sheets; and Extending
25 *Suspension Period*, dated January 3, 2023 (Order U-01-152(4)).

26 ⁴⁹ENSTAR Opening Brief at 20 (citing Order U-01-152(5), *Order Accepting*
Compliance Filing, Approving Proposal, Approving Tariff Sheet, Requiring Filing, and
Closing Docket, dated March 6, 2003 (Order U-01-152(5)).

1 the GCA provision provided for the collection of interest from customers.⁵⁰ However,
2 ENSTAR claims it has demonstrated in TA350-4 that recovery on a per-Mcf basis as a
3 cost element in ENSTAR’s GCA is reasonable and appropriate, and this is analogous to
4 what we allowed in this precedent, even though GCA recovery was denied in those
5 orders.⁵¹

6 In response to Question 6, ENSTAR argues that the proposed costs
7 identified in TA350-4 meet adjustment clause criteria listed in 3 AAC 52.502(a). ENSTAR
8 argues that importing LNG to the Cook Inlet is an unprecedented event in Alaskan history
9 and the costs to proceed with it represent unusual fuel costs.⁵² ENSTAR states that the
10 LNG Project’s development costs are subject to change at a rate that would cause
11 financial harm to ENSTAR if recovered exclusively in base rates. ENSTAR asserts that
12 the costs are beyond ENSTAR’s control because it must incur these costs to advance the
13 LNG Project. ENSTAR states that these costs will vary year-to-year and will be dictated
14 by the various project agreements and the engineering and permitting activities that it will
15 be required to complete. ENSTAR states that it has no control over these factors.
16 ENSTAR states that the costs will be easily verifiable, and it will continue to file regular
17 updates on the total balance of costs incurred, as well as a narrative statement detailing
18 the progress of the working group⁵³ in securing gas supply with its second and fourth
19 quarterly GCBA filings.⁵⁴

20 In response to Question 7, ENSTAR states that AS 42.05.441(b) is
21 inapplicable to its GCA recovery request. If the LNG Project is terminated under
22 Scenario 2, and the developer must be reimbursed, the payment will be for “an operating
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24 ⁵⁰ENSTAR Opening Brief at 20.

25 ⁵¹ENSTAR Opening Brief at 20.

26 ⁵²ENSTAR Reply at 19–20.

⁵³See *infra* Note 125.

⁵⁴ENSTAR Opening Brief at 21–22.

1 expense and not for capital investments in plant and none of the costs in TA350-4 are for
2 the construction phase or completed plant” that would be subject to AS 42.05.441(b).⁵⁵

3 ENSTAR argues that time is of the essence to move forward with the LNG
4 Project and an approved cost recovery mechanism is necessary for it to access the
5 funding required to continue progress and maintain timelines. ENSTAR states that
6 securing a cost recovery mechanism ensures ENSTAR and other Railbelt utilities can
7 enter into binding agreements with the developer and any delay has a direct negative
8 impact on the LNG Project timeline. ENSTAR characterizes TA350-4 as “the gateway for
9 the Project to advance and avoid undue risk to the public.”⁵⁶

10 RAPA

11 In response to Question 1, RAPA argues that the development costs at
12 issue in TA350-4 are inextricably linked to their subject matter, an LNG terminal.⁵⁷ While
13 recognizing that an LNG import facility normally falls within FERC’s exclusive jurisdiction
14 under the NGA, RAPA states an exception exists—the Hinshaw Amendment—that
15 provides the Commission discretionary authority to seek jurisdictional oversight. RAPA
16 asserts this docket will allow the Commission to decide “whether to exert, or not exert,
17 jurisdiction in this case.”⁵⁸

18 The prudence of the costs ENSTAR will incur for the development phase of
19 the LNG terminal ultimately depends on the prudence of development phase decisions
20 regarding the siting and construction of the project. Therefore, RAPA disagrees with
21 ENSTAR and the Railbelt cooperatives⁵⁹ that TA350-4 does not implicate a jurisdictional
22 issue. RAPA believes the jurisdictional complexity in this case arises, at least in part,

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24 ⁵⁵ENSTAR Opening Brief at 23–24; ENSTAR Reply at 20–21.

25 ⁵⁶ENSTAR Reply at 12–13.

26 ⁵⁷RAPA Opening Brief at 7.

⁵⁸RAPA Opening Brief at 9–14.

⁵⁹Chugach, GVEA, MEA, and HEA.

1 from the fact ENSTAR seeks authorization for recovery of costs related to the
2 development of an LNG facility before they are even incurred.⁶⁰

3 RAPA states that ENSTAR wants the Commission to exercise jurisdiction
4 over costs associated with a facility that ENSTAR wants to construct, prior to construction,
5 and for costs if the project is abandoned. RAPA states that this request is not analogous
6 to an LDC seeking to recover capacity costs stemming from a project that has already
7 been authorized by FERC.⁶¹

8 In response to Question 2, RAPA asserts that we specifically linked our
9 approval of the regulatory asset in Order U-22-090(2) to the understanding that the costs
10 in it related to ENSTAR’s effort to explore and study long-term solutions to the impending
11 gas supply gap in Cook Inlet. RAPA states that ENSTAR has sufficiently studied long-
12 term solutions to commit itself to developing an LNG facility in proximity to its transmission
13 and storage facilities. And because it has decided how to proceed, and the lack of “any
14 specificity regarding the precise nature of continuing costs,” the regulatory asset allowed
15 under Order U-22-090(2) should be terminated as of December 17, 2024.⁶²

16 In response to Question 3, RAPA characterizes ENSTAR’s GCA recovery
17 request in TA350-4 as “a blank check for all and any costs incurred in the future related
18 to its efforts to secure natural gas amounts to a request to fully shield its shareholders
19 from the risks [they] knowingly assumed at purchase.”⁶³ RAPA states that ENSTAR
20 currently has the highest ROE of any rate-regulated investor-owned utility in Alaska—
21 11.875%—and ENSTAR provides no rational justification for it continuing to earn its
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25 ⁶⁰RAPA Reply at 3–4.

⁶¹RAPA Reply at 7.

⁶²RAPA Opening Brief at 16; RAPA Reply at 9–10.

⁶³RAPA Opening Brief at 17.

1 current return at a premium while simultaneously eliminating any shareholder risk for
2 which ENSTAR has already been compensated.⁶⁴

3 RAPA also argues that when we authorized ENSTAR's acquisition by
4 TriSummit Utilities Inc. (TriSummit), we did so with the understanding and expectation
5 that TriSummit maintained sufficient financial resources to invest in new facilities.
6 ENSTAR's request therefore represents an attempt to shift the inherent risks TriSummit
7 already assumed, and for which it has already been rewarded, onto its ratepayers.⁶⁵

8 In response to Questions 4 through 6, RAPA first states that it cannot find
9 any precedent where we allowed a regulated utility to recover previously approved
10 regulatory asset costs through a COPA or a GCA. RAPA next states that the definition
11 of "adjustment clause" in 3 AAC 52.519(a)(1) limits what may be recovered through the
12 GCA to costs related to "changes in gas, fuel, and purchased power expense," and to
13 conclude that the costs proposed by ENSTAR amount to "changes in gas" expense would
14 extend the definition of "adjustment clause" beyond the regulation's plain language and
15 intent. RAPA also argues that ENSTAR's projected development costs of approximately
16 \$5 million are not subject to change at a rate that would cause financial harm if recovered
17 exclusively in base rates as required by 3 AAC 52.502(a)(1).⁶⁶

18 RAPA argues ENSTAR fails to explain how the costs associated with
19 studying gas supply are "beyond its control." RAPA explains that unlike the market and
20 geopolitical forces that control the current cost of gas itself, ENSTAR maintains control
21 over all the costs it chooses to incur to study gas supply options, and it cannot give
22 Glenfarne a blank check with absolutely no spending limit or controls.⁶⁷ Finally, RAPA
23 argues that unlike the third-party cost of gas currently included in ENSTAR's GCA, where

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25 ⁶⁴RAPA Opening Brief at 17–18; RAPA Reply at 10–11.

⁶⁵RAPA Reply at 11–12.

26 ⁶⁶RAPA Opening Brief at 19-22; RAPA Reply at 12–13.

⁶⁷RAPA Reply Brief at 14–15.

1 third-party invoices for gas supplies and commodity contract costs are easily verified,
2 costs related to its efforts to study long-term gas supply options are not easily verifiable.
3 RAPA states that by our noting in Order U-22-090(2) that we would “investigate” the costs
4 included in the regulatory asset, we already recognized that those costs do not lend
5 themselves to easy verification.⁶⁸

6 In response to Question 7, RAPA states the “used and useful” language of
7 AS 42.05.441(b), and our precedent applying it, relate to the proper valuation of utility
8 property included in rate base. Because terminated project development costs will never
9 attach to “used and useful” property, RAPA suggests “AS 42.05.441(b), on its own, does
10 not necessarily bar recovery of costs associated with an abandoned project.”⁶⁹ But RAPA
11 says that TA350-4 fails to address how these costs would otherwise be treated from a
12 regulatory accounting perspective.⁷⁰

13 RAPA concludes that the decision of whether to allow a utility to recover
14 costs associated with cancelled or abandoned projects must be made on a case-by-case
15 basis where a determination of the prudence of the initial investment can be made, as
16 well as the prudence of an ultimate decision to abandon the project. RAPA asserts that
17 it would not be just and reasonable to pass costs on to ratepayers without any opportunity
18 for investigation or examination into their prudence.⁷¹

19 JLP/RSD

20 In response to Question 1, JLP/RSD assert that FERC’s exclusive authority
21 and duty to balance the public’s interest in interstate natural gas projects preempts
22 actions under state or local law that would affect projects like the LNG facility discussed
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24 _____
25 ⁶⁸RAPA Opening Brief at 22–23.

26 ⁶⁹RAPA Opening Brief at 25.

⁷⁰RAPA Opening Brief at 25.

⁷¹RAPA Opening Brief at 25–28.

1 in TA350-4.⁷² JLP/RSD state that whether we are preempted by the NGA turns on the
2 question of whether the act is a regulation of rates and facilities of natural gas companies
3 used in transportation and sale or resale in interstate commerce.⁷³

4 JLP/RSD argue that we do not have and should not exercise jurisdiction
5 over LNG import facilities. JLP/RSD assert that ENSTAR is planning to advance funds
6 for the LNG Project that will receive gas transported in interstate commerce and is defined
7 in TA350-4 as “construct[ion] of a natural gas receiving terminal on the Kenai Peninsula,
8 in close proximity to ENSTAR transmission and storage facilities.”⁷⁴ JLP/RSD cite
9 15 U.S.C § 717b(e)(1) which states that FERC “shall have the exclusive authority to
10 approve or deny an application for the siting, construction, expansion, or operation of an
11 LNG terminal.” Therefore, JLP/RSD argue that the LNG Project, as defined by ENSTAR,
12 and all agreements related to the interstate transportation of natural gas, are subject to
13 exclusive FERC jurisdiction.⁷⁵

14 JLP/RSD state that it is undisputed that the LNG Project will receive LNG in
15 interstate commerce and therefore it is clearly subject to FERC jurisdiction. JLP/RSD
16 stress that the LNG import facility will not be subject to the exemption set forth in
17 15 U.S.C. § 717(c) (the Hinshaw Amendment) and ENSTAR improperly seeks to cast
18 itself as an exempt *entity* under 15 U.S.C. § 717(c). JLP/RSD states that a proper
19 analysis focuses on “the *facilities* or *activities* at issue” instead.⁷⁶

20 JLP/RSD argue that it is improper to require ratepayers to pay ENSTAR for
21 costs attributable to a FERC-regulated LNG import facility. JLP/RSD stress the lack of
22 detail in TA350-4 and state that with the level of information provided, it is apparent that
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24 ⁷²JLP/RSD Opening Brief at 2–3.

25 ⁷³JLP/RSD Opening Brief at 3–5.

26 ⁷⁴JLP/RSD Reply at 3.

⁷⁵JLP/RSD Reply at 3–4.

⁷⁶JLP/RSD Reply at 3–5.

1 ENSTAR is largely seeking to recover costs directly related to a FERC-regulated facility
2 that is outside of this Commission’s jurisdiction.⁷⁷

3 JLP/RSD argue that the Legislature’s intent to restrict Commission
4 jurisdiction by adopting AS 42.05.711(v) was shown when it expressly decided to remove
5 language stating “[f]or rate-making purposes, the commission shall consider the
6 investment of a public utility in a liquified natural gas import or export facility” from HB 50.
7 JLP/RSD assert this language appeared in the Senate Finance Committee draft of HB 50
8 but was subsequently amended to state, “For rate-making purposes, the commission
9 shall not consider the investment of a public utility in a liquified natural gas import or export
10 facility.”⁷⁸

11 As to Joint Development Agreement costs, JLP/RSD state that ENSTAR
12 has failed to provide any detail regarding what its obligations may be under such an
13 agreement and the agreement is clearly related to the development of the LNG import
14 facility, which is a non-jurisdictional project.⁷⁹

15 As to the Terminal Use Agreement and LNG Sales and Purchase
16 Agreement, JLP/RSD state that “ENSTAR apparently plans to purchase gas outside of
17 Alaska for import to the facility and to utilize the facility to regasify the LNG for use in
18 Alaska.” JLP/RSD state that this “activity constitutes interstate transportation of gas and
19 is squarely within FERC’s jurisdiction.”⁸⁰

20 As to any gas sales agreement, JLP/RSD state that “costs associated
21 exclusively with negotiating a gas sales agreement for the purchase of and use of gas
22 within Alaska may be properly recoverable to the extent they are prudently incurred.”
23 However, JLP/RSD state such costs are only recoverable after they have been incurred
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25 ⁷⁷JLP/RSD Reply at 5–7.

26 ⁷⁸JLP/RSD Opening Brief at 5–6.

⁷⁹JLP/RSD Reply at 7.

⁸⁰JLP/RSD Reply at 7.

1 and after we have had an opportunity to review them. JLP/RSD conclude that “ENSTAR
2 improperly seeks pre-approval to recover such costs long before they are incurred.”⁸¹

3 As to ENSTAR’s engineering and project management oversight of the
4 developer’s activities, JLP/RSD state that we “cannot properly cause ENSTAR ratepayers
5 to pay for engineering and project management oversight for a non-jurisdictional project
6 through jurisdictional rates.”⁸² JLP/RSD state that any costs associated with engineering
7 and project management for a FERC-regulated facility may not be recovered through
8 rates we set.

9 JLP/RSD state that to the extent permitting costs are associated with an
10 LNG import facility outside of our jurisdiction, such costs are also not properly recoverable
11 through rates set by us.⁸³

12 In response to Question 2, JLP/RSD state that ENSTAR’s request falls far
13 outside our scope of approval in Order U-22-090(2). JLP/RSD also argue costs incurred
14 under the exclusivity agreement are “amounts allocated to future capital projects,” which
15 should similarly be “exempted from recovery under Order U-22-090(2).”⁸⁴

16 In response to Question 3, JLP/RSD argue that the ROE received by
17 ENSTAR “serves as compensation for the assumption of risks associated with ENSTAR’s
18 business operations, including the risk that speculative projects will never become used
19 and useful.” JLP/RSD surmise that by seeking to recover costs associated with the LNG
20 Project through rates, ENSTAR is “shifting a risk that it has assumed onto ratepayers.”⁸⁵

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24 ⁸¹JLP/RSD Reply at 9.

25 ⁸²JLP/RSD Reply at 10.

26 ⁸³JLP/RSD Reply at 10–11.

⁸⁴JLP/RSD Opening Brief at 8–9.

⁸⁵JLP/RSD Opening Brief at 9–11.

1 JLP/RSD find further support for their argument by citing our finding of
2 financial fitness for ENSTAR's parent TriSummit in Order U-22-032(6)/U-22-033(6),
3 where we said:

4 We further find that TriSummit Utilities Inc.'s past financial performance and
5 demonstrated financial resources are sufficient to provide financial support to
6 ENSTAR Natural Gas Company, LLC; Alaska Pipeline Company, LLC; and
7 CINGSA, as may be required to fund investment in new facilities and costs
8 associated with unexpected occurrences.⁸⁶

9 JLP/RSD also cite to Order U-22-081(14) where we noted that the creation
10 of the regulatory asset in Order U-22-090(2) "provides additional insulation for ENSTAR
11 from losses or costs incurred to find a long-term supply of gas and shifts the risk and costs
12 to future ratepayers" and "any negative economic factors that affect a utility also affect
13 ratepayers at a personal level and it is not proper to insulate the utility and shift all negative
14 effects to the ratepayers."⁸⁷

15 Further, JLP/RSD cite our order setting ENSTAR's ROE at 11.875% which
16 was found to be beneficial for ENSTAR to secure new gas supplies:

17 We acknowledge that there is a looming gas shortage in the Cook Inlet and
18 ENSTAR may have to spend or borrow significant funds in the future to secure
19 a gas supply. Meanwhile, ENSTAR's current ROE has been steadily earning
20 sufficient revenue and maintaining healthy equity for the company. We find
21 that ENSTAR's current equity position will be beneficial for ENSTAR if those
22 investments have to be made.⁸⁸

23 JLP/RSD also point to FERC authority on this issue. They note FERC has
24 held, "the financial risk of committing funds to study or to initiate projects which may be
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26 ⁸⁶JLP/RSD Opening Brief at 10 (citing Order U-22-032(6)/U-22-033(6), *Order Approving Applications Effective on the Date of the Closing of the Transactions, Requiring Filings, and Amending Docket Caption*, dated December 21, 2021 (Order U-22-032(6)/U-22-033(6)) at 39).

⁸⁷JLP/RSD Opening Brief at 10 (citing Order U-22-081(14), *Order Resolving Return of Equity Issue, Requiring Filings, and Redesignating Commission Panel*, dated April 8, 2024 (U-22-081(14)) at 33).

⁸⁸JLP/RSD Opening Brief at 10 (citing Order U-22-081(14) at 34).

1 completed is a business risk which management and the stockholders should bear—one
2 of the business risks for which they earn a rate of return.”⁸⁹

3 In response to Question 4, JLP/RSD state that it is ENSTAR’s burden to
4 establish the prudence of costs it seeks to include in rates, and it is impossible to
5 determine now whether the costs ENSTAR will incur in the future are prudent, necessary,
6 or provide any benefit to ratepayers; nevertheless, this is precisely what ENSTAR
7 requests with TA350-4. JLP/RSD assert that ENSTAR seeks recovery of costs related
8 to engaging legal, commercial, and technical experts which are not a commodity cost and
9 should be treated differently than other gas costs. JLP/RSD state that ENSTAR’s
10 previous attempt to recover legal and consulting costs through a GCA was rejected, and
11 this conclusion is consistent with our recent letter order issued denying TA384-13 and
12 TA385-13, where we said:

13 The COPA is not a catch-all for any “fuel-related” expense. The lease
14 expenses in TA384-13 include construction costs, utilities, property taxes, and
15 many other non-fuel components. The operation expenses in TA385-13
16 include PSI’s overhead, hiring/contracting, insurance, and other non-fuel
17 components as well. These expenses are negotiated, fixed recurring charges,
18 which are not subject to change at a rate that would cause financial harm if
19 recovered exclusively through base rates as required by 3 AAC 52.502(a)(1)
20 and are not beyond control of the utility as required by 3 AAC 52.502(a)(2).⁹⁰

21 Finally, JLP/RSD state that costs related to development, engineering,
22 procurement, commissioning, construction, and operation of the pipeline required to
23 receive regasified LNG are capital expenditures related to the construction of intrastate
24 pipeline facilities and may be properly recovered through rates, but not through the GCA
25 mechanism. JLP/RSD state that “after such facilities are constructed, ENSTAR may seek

25 ⁸⁹JLP/RSD Opening Brief at 11 (citing *Transwestern Pipeline Co.*, 14 FERC ¶
26 63,065, 65,199 (1981)).

⁹⁰JLP/RSD Opening Brief at 12–13; JLP/RSD Reply at 11–12 (quoting TA384-13
and TA385-13; Letter Order No. L2500013, dated January 17, 2025).

1 Commission approval for including them in rate base and recovering associated costs
2 through rates.”⁹¹

3 In response to Question 5, JLP/RSD state that a survey of Commission
4 orders revealed no precedent allowing the recovery of previously approved regulatory
5 asset costs through a COPA or a GCA. JLP/RSD state that ENSTAR is attempting to
6 use elements of our cost-based ratemaking authority to manage risk for a project
7 regulated by FERC under market-based regulation. JLP/RSD assert that ENSTAR seeks
8 the protection of cost-based ratemaking principles to protect its investment while the LNG
9 Project, if it is ever constructed, will provide ratepayers with none of the benefits of cost-
10 based ratemaking.⁹²

11 In response to Question 6, JLP/RSD state that TA350-4 is not consistent
12 with the provisions of 3 AAC 52.502(a). They assert that ENSTAR has failed to show that
13 it will face financial harm if the costs are recovered exclusively in base rates. JLP/RSD
14 further assert that ENSTAR did not support ENSTAR’s President Sims’ statement that
15 “[a]bsent a cost element, ENSTAR will have to find a different mechanism for the recovery
16 of costs if the project is suspended,” which ENSTAR asserts “will cause significant delay.”
17 JLP/RSD state that “ENSTAR fails to explain how costs driven by contractual
18 arrangements that it alone will enter into are outside of ENSTAR’s control.”⁹³

19 In response to Question 7, JLP/RSD argues that if the LNG Project does
20 not proceed to construction, reimbursing Glenfarne for up to \$48 million would be
21 inconsistent with the well-settled principle that only operating expenses associated with
22 used and useful plant can be included in rates. JLP/RSD state that the used and useful
23 principle is intended to protect ratepayers from bearing the cost of the exact type of
24 speculative investment that ENSTAR seeks to recover and ENSTAR should not be

25 ⁹¹JLP/RSD Reply at 10.

26 ⁹²JLP/RSD Opening Brief at 6–7.

⁹³JLP/RSD Opening Brief at 14–15.

1 permitted to recover its investment unless and until it satisfies the used and useful
2 standard.⁹⁴

3 Chugach

4 In response to Question 1, Chugach argues that FERC’s jurisdiction over
5 the siting, construction, operation, or expansion of an LNG import or export facility is
6 exclusive under 15 U.S.C. § 717b(e).⁹⁵ However, Chugach points out FERC’s jurisdiction
7 does not extend to price regulation of imported LNG,⁹⁶ nor to an LDC’s decision to procure
8 gas supplies or capacity in a FERC jurisdictional project like an LNG import facility. The
9 review of those determinations falls to state regulatory commissions who hold
10 jurisdictional authority to review such terms.⁹⁷

11 Chugach argues FERC’s jurisdiction over the LNG import facility ENSTAR
12 describes in TA350-4 is not subject to the Hinshaw Amendment, which could otherwise
13 provide a potential vehicle for this Commission’s oversight. Instead, FERC’s jurisdiction,
14 and the application of the Hinshaw Amendment, depends on whether foreign commerce
15 is involved. As Chugach explains, “the Hinshaw Amendment’s exemption from FERC’s
16 Section 7 jurisdiction for intrastate pipelines receiving interstate gas within a state for
17 ultimate consumption within that same state has no bearing on FERC’s Section 3
18 jurisdiction over LNG terminals operating in foreign commerce.”⁹⁸ Since the Glenfarne
19 LNG facility will be involved in foreign commerce, Chugach argues there can be no
20 assertion of this Commission’s jurisdiction over the facility, nor any authority to assess
21 whether any duplication of LNG import facilities would be barred by AS 42.05.221(d).⁹⁹

22 ⁹⁴JLP/RSD Opening Brief at 16; JLP/RSD Reply 11 (citing Order U-04-022(38)
23 /U-04-023(38), *Order Approving Interim Rates as Permanent Rates and Closing Dockets*,
dated, June 27, 2011).

24 ⁹⁵Chugach Opening Brief at 2–3; Chugach Reply at 7.

25 ⁹⁶Chugach Opening Brief at 5.

26 ⁹⁷Chugach Opening Brief at 6–7; Chugach Reply at 7–8.

⁹⁸Chugach Reply at 2–4.

⁹⁹Chugach Reply at 4–6.

1 In response to Questions 2 and 3, Chugach takes no position on the status
2 of ENSTAR’s authorized regulatory asset or ENSTAR’s request in general.¹⁰⁰

3 Chugach also takes no position on Question 4, but notes a similar
4 requirement was imposed upon Chugach when it requested authorization to create a
5 regulatory asset to defer and amortize transaction costs associated with its acquisition of
6 the Anchorage Municipal Light & Power’s assets. There we stated “consistent with
7 Chugach’s request and our practice, we will allow recovery through future rates of only
8 those transaction costs that were prudently incurred.”¹⁰¹ Chugach also argues that when
9 GCA or COPA cost recovery is requested, it would “typically be reviewed for potential
10 recovery through rates in an after-the-fact proceeding when the proposed contracts have
11 been executed and the costs to be recovered are known.”¹⁰²

12 In response to Question 5, Chugach states it is unaware of any precedent
13 where the Commission has allowed a regulated utility to recover previously approved
14 regulatory asset costs through a COPA or a GCA. But Chugach suggests “that the fact
15 that costs are associated with a regulatory asset should not be determinative of whether
16 those costs can be appropriately included within a COPA or a GCA.”¹⁰³

17 In response to Question 6, Chugach takes no position on whether TA350-4
18 is consistent with 3 AAC 52.505(a).¹⁰⁴

19 In response to Question 7, Chugach takes no position on the
20 reasonableness of TA350-4 but cites to the used and useful standard in *BP Pipelines*
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22 ¹⁰⁰Chugach Opening Brief at 14.

23 ¹⁰¹Chugach Opening Brief at 15 (citing Order U-18-102(44)/U-19-020(39)/
24 U-19-021(39), *Order Accepting Stipulation in Part, Subject to Conditions; Amending,
25 Transferring and Issuing Certificates of Public Convenience and Necessity, Subject to
26 Conditions; Addressing Beluga River Unit Management, Gas Transfer Prices, and Third
Party Sales Gas Pricing; and Requiring Filings*, dated May 28, 2020, at 141–142).

¹⁰²Chugach Reply Brief at 9.

¹⁰³Chugach Opening Brief at 15.

¹⁰⁴Chugach Opening Brief at 15–16.

1 (*Alaska Inc.*, 2014 WL 897389 (Alaska 2014) as guidance for our analysis. Chugach
2 states that we should endeavor to ensure that, absent good cause, long-standing
3 regulatory principles like the used-and-useful standard are consistently applied to
4 regulated utilities in Alaska.¹⁰⁵

5 GVEA, HEA, and MEA

6 In response to Question 1, GVEA argues that we have jurisdiction to
7 consider ENSTAR’s costs as part of our statutory authority over the rates, services,
8 operations, and practices of certificated public utilities and pipelines. GVEA asserts that
9 we should not complicate our decision-making process by focusing on an LNG terminal
10 facility that is not constructed or operating. GVEA asserts that jurisdiction over an LNG
11 facility is a separate issue that is not ripe for our consideration.¹⁰⁶

12 HEA argues the costs addressed by TA350-4 are related to ENSTAR’s
13 efforts to secure a long-term gas supply. HEA states that ENSTAR and Glenfarne have
14 only signed an exclusivity agreement related to the development phase of the LNG
15 Project and neither has brought forth an application for the siting, construction, expansion,
16 or operation of an LNG terminal, which falls under FERC’s exclusive jurisdiction.¹⁰⁷

17 MEA claims the jurisdictional issues presented in TA350-4 boil down to the
18 question of “what constitutes LNG import activity versus activities undertaken to distribute
19 natural gas in state and where is the line of demarcation between the two.”¹⁰⁸ While MEA
20 does not squarely answer its own question,¹⁰⁹ it does argue that ENSTAR is not asking
21 to construct an LNG import facility, but instead is only asking to recover costs associated

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23 ¹⁰⁵Chugach Opening Brief at 17.

24 ¹⁰⁶GVEA Opening Brief at 1–3.

25 ¹⁰⁷HEA Opening Brief at 5.

26 ¹⁰⁸MEA Reply at 4–5.

¹⁰⁹MEA says the demarcation line between FERC and Commission jurisdiction depends on “how the RCA interprets its authority versus FERC’s and applicable statutory or case law exceptions to the definition of ‘LNG terminal.’” MEA Reply at 5.

1 with studying and securing long-term gas supply and developer costs. MEA states that if
2 Glenfarne does not move forward to construction of the project there will be no LNG
3 import facility to fall under FERC’s jurisdiction, therefore the recovery of the costs in
4 ENSTAR’s rates falls within our regulatory authority.¹¹⁰

5 In response to Question 2, GVEA, MEA and HEA each argue that the
6 exclusivity agreement between ENSTAR and Glenfarne is a beginning, not the end, of
7 the process to secure natural gas for the Railbelt. As GVEA puts it, “[u]ntil such time that
8 ENSTAR is no longer ‘studying gas supply options’ but has *secured long-term natural gas*
9 *for the Cook Inlet*, GVEA believes that the regulatory asset allowed by . . . Order
10 U-22-090(2) should not be terminated because the reason upon which the Commission’s
11 permission for regulatory asset treatment persists.”¹¹¹

12 HEA also notes its own unique circumstances. HEA states that it is
13 currently relying on an interruptible gas supply agreement with ENSTAR, which to its
14 knowledge is the first time a Railbelt utility has not had access to a firm gas supply
15 contract and is at risk of curtailment due to lack of a fuel supply.¹¹² It therefore urges us
16 not to erect barriers to the LNG Project’s economics based on aspersions related to
17 ENSTAR’s corporate structure.¹¹³

18 In response to Question 3, GVEA and MEA state that ENSTAR will not be
19 dedicating any capital assets associated with these agreements, therefore there is no
20 investment being made on which a return can be earned.¹¹⁴ HEA does not view the
21 development and eventual construction of Alaska’s first LNG import facility as a normal
22 cost of business for ENSTAR that was or should have been contemplated by us and

23 ¹¹⁰MEA Opening Brief at 3.

24 ¹¹¹GVEA Opening Brief at 3; HEA Opening Brief at 7; MEA Opening Brief at 4,
25 Reply at 2–3.

26 ¹¹²HEA Reply at 2–3.

¹¹³HEA Reply at 3–4.

¹¹⁴GVEA Opening Brief at 4; MEA Opening Brief at 4.

1 included in ENSTAR’s ROE. Nor does HEA view ENSTAR’s ROE as covering the unique
2 risks of the LNG Project which entails significant urgency, complexity, scale, and capital
3 requirements.¹¹⁵

4 In response to Question 4, GVEA and HEA state we used the term “rate
5 making proceeding” in Order U-22-090(2), and not “rate case,” making it unclear what we
6 were requiring.¹¹⁶ While MEA acknowledges we intended the regulatory asset authorized
7 by Order U-22-090(2) to be reviewed in a rate case, it alternatively supports ENSTAR’s
8 request to use its GCA provided “comparable transparency” to “what would be expected
9 in a rate case” is provided.¹¹⁷

10 In response to Question 5, GVEA and MEA state they are unaware of
11 circumstances where a public utility was permitted to create a regulatory asset and then
12 allowed a cost recovery approach like what ENSTAR is requesting.¹¹⁸ HEA, however,
13 points to its approved Wholesale Power Cost Rate Adjustment (WPCRA) charge
14 proposed in TA260-32 as analogous. HEA states that both the WPCRA and the GCA are
15 adjustment mechanisms meant to ensure that utilities can recover their costs in real time
16 to limit excessive financial risk.¹¹⁹

17 In response to Question 6, GVEA and HEA assert that the costs ENSTAR
18 seeks to recover in TA350-4 meet the criteria for GCA recovery outlined in
19 3 AAC 52.502(a).¹²⁰ GVEA also argues that outside of a rate case, GCA recovery is the
20 only available vehicle for ENSTAR to use to recover these costs.¹²¹

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23 ¹¹⁵HEA Opening Brief at 8–9.

¹¹⁶GVEA Opening Brief at 4; HEA Opening Brief at 10.

¹¹⁷MEA Opening Brief at 4.

¹¹⁸GVEA Opening Brief at 5; MEA Opening Brief at 5.

¹¹⁹HEA Opening Brief at 11–12.

¹²⁰GVEA Opening Brief at 6; HEA Opening Brief at 12–13.

¹²¹GVEA Opening Brief at 6.

1 In response to Question 7, GVEA, MEA and HEA all state (or imply) that the
2 development costs incurred for a terminated project are not subject to AS 42.05.441(b).
3 The statute applies to rate base valuation which would not be implicated where a facility
4 is not built.¹²² In addition, MEA argues allowing ENSTAR to recover Developer Costs if
5 the Project is terminated is analogous to situations where the Commission has reviewed
6 requests to allow acquisition adjustments in rates. As MEA puts it, if the Project is
7 terminated, then the public interest tests we employ to review acquisition adjustments can
8 be used here to conclude ENSTAR's lump-sum payment recovery under Scenario 2
9 would be in the public interest.¹²³

10 Analysis

11 Jurisdiction

12 There are several jurisdictional issues raised by the parties. The first is
13 whether this Commission may seek to acquire jurisdiction over an LNG import facility
14 such as that discussed in TA350-4. While no party disputes that FERC has exclusive
15 jurisdiction over the "siting, construction, expansion, or operation" of an LNG import facility
16 used in either interstate or foreign commerce under the NGA,¹²⁴ RAPA points to the
17 Hinshaw Amendment as a vehicle for this Commission to assume jurisdiction.

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¹²²HEA Opening Brief at 13–14; GVEA Opening Brief at 7; MEA Opening Brief at 6.

24 ¹²³MEA Reply Brief at 3–4.

25 ¹²⁴15 USC § 717b(e)(1). The NGA defines an LNG terminal to include: "[A]ll natural
26 gas facilities located onshore or in State waters that are used to receive, unload, load,
store, transport, gasify, liquify, or process natural gas that is imported to the United States
from a foreign country, exported to a foreign country from the United States, or
transported in interstate commerce by waterborne vessel" 15 USC § 717a(11).

1 The Hinshaw Amendment is codified at 15 USC § 717(c). It provides:

2 The provisions of this chapter shall not apply to any person engaged in or
3 legally authorized to engage in the transportation in interstate commerce or
4 the sale in interstate commerce for resale, of natural gas received by such
5 person from another person within or at the boundary of a State if all the natural
6 gas so received is ultimately consumed within such State, or to any facilities
7 used by such person for such transportation or sale, provided that the rates
8 and service of such person and facilities be subject to regulation by a State
9 commission. The matters exempted from the provisions of this chapter by this
10 subsection are declared to be matters primarily of local concern and subject to
11 regulation by the several States. A certification from such State commission
12 to the Federal Power Commission that such State commission has regulatory
13 jurisdiction over rates and service of such person and facilities and is
14 exercising such jurisdiction shall constitute conclusive evidence of such
15 regulatory power or jurisdiction.

16 Because LNG imported to the proposed developer's facility is to be
17 transported and consumed within Alaska, RAPA claims the Hinshaw Amendment allows
18 us to seek jurisdictional oversight of the facility. We disagree. ENSTAR's LNG source is
19 likely to be from Canada or Mexico, meaning foreign commerce, not interstate commerce
20 is implicated.¹²⁵ The Hinshaw Amendment by its own terms applies to interstate
21 commerce, not foreign commerce. FERC's jurisdiction over an LNG import facility
22 appears to be exclusive where foreign commerce is the source of LNG imports.¹²⁶

23 We note that even if LNG was ultimately obtained from a domestic source,
24 or if access to state commission jurisdiction under the Hinshaw Amendment was as broad

25 ¹²⁵As ENSTAR states in TA350-4 at 1–2, the Railbelt electric utilities and ENSTAR
26 formed a "Working Group" in 2022 to identify options to meet future gas supply needs.
The Working Group contracted with the Berkley Research Group (BRG) to provide
guidance. BRG produced a report for the Working Group in June 2023 identifying Canada
or Mexico as the most likely source for imported LNG. See
[www.enstarnaturalgas.com/wp-content/uploads/2023/06/CIGSP-Phase-I-Report-BRG-
28June2023.pdf](http://www.enstarnaturalgas.com/wp-content/uploads/2023/06/CIGSP-Phase-I-Report-BRG-28June2023.pdf) at page 50.

¹²⁶See *New Forest Energy, LLC*, 174 FERC ¶ 61,207 (2021), *aff'd* 36 F.4th 1172
(D.C. Cir. 2022) at P. 28 ("Because the New Fortress Energy facility includes facilities
dedicated to the importation of LNG in foreign commerce, is located at or near the point
of import, and includes a pipeline that sends out gas, it is an LNG terminal subject to the
Commission's jurisdiction."); *Trans-Foreland Pipeline Co. LLC*, 173 FERC ¶ 61,253
(2020) at P. 8 ("Because the proposed facilities will be used to import natural gas from
foreign countries, the construction and operation of the proposed facilities and site of their
location require approval by the Commission under Section 3 of the NGA.").

1 as RAPA claims, we do not see a viable path to acquiring jurisdiction. Were we to do so,
2 we would violate AS 42.05.711(v). This subsection provides that “A liquified natural gas
3 import facility under the jurisdiction of the Federal Energy Regulatory Commission is
4 exempt from this chapter.”

5 This subsection was adopted via HB 50 in 2024. Not only does this
6 subsection’s express language appear to clearly bar our assumption of jurisdiction, but
7 the legislative history underlying its enactment reinforces this conclusion.¹²⁷ Therefore,
8 if we were to assert LNG facility oversight under the Hinshaw Amendment which RAPA
9 suggests is possible, we would be disregarding the jurisdictional side boards imposed on
10 us by the legislature. We decline to do so.¹²⁸

11 The second jurisdictional issue presented by the parties addresses whether
12 FERC or this Commission’s jurisdiction would attach to development costs identified in
13 TA350-4. RAPA claims these costs “are inextricably linked to their subject matter, an
14 LNG terminal.”¹²⁹ JLP/RSD make similar arguments.¹³⁰

15 We note initially that a different analysis applies when looking at
16 development costs under ENSTAR’s Scenario 1 compared to Scenario 2. Under
17 Scenario 1, if the LNG Project advances to construction, the only development costs

20 ¹²⁷JLP/RSD Opening Brief at 5 & n.19 points to minutes and amendments
21 preceding the adoption of AS 42.05.711(v). Section 40 of Version T, SCS CSHB50, dated
22 May 10, 2024, had included a proposed amendment to AS 42.05.381 which would have
23 granted the Commission jurisdiction to “consider the investment of a public utility in a
24 liquified natural gas import facility as utility property, even if the liquified natural gas import
or export facility is exempt from regulation by the commission.” This subsection was
eliminated by Amendment 4, dated May 11, 2024. See JLP/RSD Opening Brief at
Exhibit 2.

25 ¹²⁸Because we do not have jurisdiction over an LNG import facility, we also lack
authority to assess whether a duplication of facilities, such as that announced by Harvest
Midstream, would be contrary to the public interest under AS 42.05.221(d).

26 ¹²⁹RAPA Opening Brief at 7.

¹³⁰JLP/RSD Reply at 5–11.

1 addressed for GCA recovery in TA350-4 are ENSTAR’s development costs.¹³¹ Case law
2 cited by Chugach clearly shows we would maintain jurisdiction to review ENSTAR’s
3 Scenario 1 development costs,¹³² but only to the extent that they are not related to the
4 siting, construction or operation of the LNG facility. Costs related to the siting,
5 construction, or operation of the LNG facility would be non-jurisdictional and excluded
6 from rates.¹³³

7 Under Scenario 2, a different analysis applies. In TA350-4, ENSTAR says
8 it will seek GCA recovery of its own development costs (estimated at \$5.4 million) and the
9 Developer’s Costs (estimated at \$43 to \$48 million) if the LNG Project is “suspended,
10 terminated or otherwise cancelled.”¹³⁴ We do not see a FERC jurisdictional problem
11 under Scenario 2. If the LNG Project is terminated or cancelled, there will be no LNG
12 import facility upon which FERC jurisdiction could attach. We will be free to examine these

13
14 ¹³¹Developer Costs are not slated for GCA recovery under Scenario 1. ENSTAR
15 says they would instead be “recovered through supply purchase or import terminal use
16 agreements.” TA350-4 at 4.

17 ¹³²See Chugach Opening Brief at 7 & n.25 (citing *Transcontinental Gas Pipe Line*
18 *Co., LLC*, 190 FERC ¶ 61,048 at P. 36 (2018) and *Mountain Valley Pipeline, LLC*, 161
19 FERC ¶ 61,043 at P. 53 (2017)).

20 ¹³³See, *Florida Gas Transmission Co. v. F.E.R.C.*, 604 F.3d 636, 646-47 (D.C. Cir.
21 2010) (holding FERC did not have jurisdiction to establish a cost-recovery mechanism for
22 expenses incurred by non-jurisdictional downstream gas users, such as electric
23 generators and local distribution companies, when they modified and upgraded their
24 equipment to handle gas delivered under new interchangeability standards for imported
25 LNG. FERC’s jurisdiction was limited to ensuring that the transportation service rates,
26 terms, and conditions were just and reasonable, and it could not require non-jurisdictional
parties to reimburse these costs); *Williston Basin Interstate Pipeline Co.*, 76 FERC ¶
61,066, 61,382 (1996) (“The non-jurisdictional costs are excluded because no non-
jurisdictional costs should be included in a pipeline’s jurisdictional rates.”); *Venice*
Gathering Co. and Venice Energy Services Chevron U.S.A. Inc., Venice Gathering Co.,
Venice Energy Services Co., and Venice Gathering System, L.L.C. Samedan Oil Corp.,
97 FERC ¶ 61,045, 61,242 n.18 (F.E.R.C. 2001) (“The costs associated with the Delta
Gathering Station were previously included in the transmission rates for the Venice
system. However, if that facility was declared to be non-jurisdictional, the costs would be
removed from the Venice system’s rate base and, thus, would not be recovered by the
transmission rates. The separate rates charged for services provided to shippers by the
Delta Gathering Station, if it was found to be non-jurisdictional, would not be regulated by
the Commission.”).

¹³⁴TA350-4 at 4.

1 costs for prudence and reasonableness when they are presented in a rate case for our
2 review.¹³⁵

3 A third jurisdictional question arose in conjunction with ENSTAR's
4 description of gas supply and terminal use agreements that will be presented to us after
5 the LNG Project is viable. As ENSTAR argues:

6 FERC jurisdiction ends where the LNG Terminal connects to a state-regulated
7 pipeline. . . . [and it] does not extend to the purchase of LNG supply or the
8 purchase of the service from LNG importation and regasification facilities.
9 Instead, intrastate activities in Alaska by a[n] [LDC] local natural gas
10 transportation and distribution company are regulated by this Commission –
11 including interactions with an LNG Terminal regulated by FERC.¹³⁶

12 To illustrate this point, ENSTAR provides a useful analogy:

13
14
15 ¹³⁵We were concerned at the prehearing conference held in this docket on
16 February 13, 2025, when ENSTAR's president emphatically stated ENSTAR would not
17 consider participating in or using an alternative LNG import facility project recently
18 announced. See Tr. 12-13:

19 [I]n 2024, I made the very, very clear statement to the group that there is no
20 world in which ENSTAR will participate in a project that has a Hilcorp-owned
21 entity as the importer of natural gas. . . . ENSTAR, as a natural gas utility, will
22 not be reliant upon an entity that provides Cook Inlet gas, Cook Inlet storage
23 and the importation of LNG, full stop. We cannot do that from a long-term
24 strategic perspective, from a planning perspective. That is way too much risk
25 for our customers I also believe that there's a massive benefit to the
26 ratepayer for participating in the same projects. Chugach has said that that is
not a competing project, they are 100 percent correct. It does not compete with
what we are looking to do in any way, shape or form because ENSTAR will
not participate in that project because of the reasons I've stated.

24 We emphasize that ENSTAR's decision to enter into an exclusivity agreement with
25 Glenfarne does not usurp or limit the scope of our prudence review authority. Thus, our
26 prudence review of development costs under either Scenario 1 or 2, as well as our review
of any gas supply or terminal use agreements, will likely include an assessment of
whether a prudent utility manager should have considered or selected a competing LNG
import facility option to meet ENSTAR's gas supply needs.

¹³⁶ENSTAR Opening Brief at 10–11.

1 Ultimately, these costs are no different from a Commission jurisdiction
2 standpoint than ENSTAR's costs to negotiate and enter into a gas sales
3 agreement with an unregulated (by the Commission) Cook Inlet gas producer.
4 Like an LNG import terminal, the Commission does not have jurisdiction over
5 the siting or construction of Cook Inlet producers' platforms and pipelines, but
6 it does have jurisdiction to regulate ENSTAR as a utility-offtaker of those
7 facilities. The import facility itself may not be regulated by this Commission,
8 but ENSTAR's interconnection with an LNG Terminal, and any necessary gas
9 purchase agreements or terminal use agreements, are all firmly within this
10 Commission's jurisdiction.¹³⁷

11 JLP/RSD dispute this. JLP/RSD claim because gas sales and terminal use
12 agreements stem from ENSTAR's plans to "purchase gas outside of Alaska for import to
13 the facility and to utilize the facility to regasify the LNG for use in Alaska," that "[t]his
14 activity constitutes interstate transportation of gas and is squarely within FERC's
15 jurisdiction."¹³⁸

16 We disagree.¹³⁹ We find ENSTAR's analogy to our current jurisdictional
17 boundaries for our review of Cook Inlet gas supply contracts useful. We also find case
18 law presented by Chugach persuasive on this issue. Both *Transcontinental Gas*¹⁴⁰ and

19 ¹³⁷ENSTAR Opening Brief at 12.

20 ¹³⁸JLP/RSD Reply at 7.

21 ¹³⁹We note that we do not have any gas supply or terminal use agreements before
22 us. Nor do we have specific facts to assess the contours of any such agreements.
23 Therefore, our opinion on this issue is generic and based only on the generalities
24 presented and is subject to modification to the extent any agreements brought before us
25 later warrant our doing so.

26 ¹⁴⁰190 FERC ¶ 61,048 at P. 36 (2025) ("[W]e reaffirm that oversight of LDC
procurement decisions is outside the Commission's jurisdiction and best left to state
regulators. Absent credible evidence of self-dealing, an attempt by the Commission to
look behind precedent agreements to independently review the decision-making of an
LDC might infringe upon the role of state regulators in determining the prudence of
expenditures by the utilities they regulate. Therefore, 'issues related to the utility's ability
to recover costs associated with its decision to subscribe for service on the [project]
involve matters to be determined by the [state regulator]; those concerns are beyond the
scope of the Commission's jurisdiction. Here, New Jersey has the authority to conduct a
prudence review to ascertain whether an LDC's capacity purchases and attendant costs
are just and reasonable and whether it is appropriate to pass those costs onto
customers.").

1 *Mountain Valley Pipeline*¹⁴¹ are on point and show we have jurisdiction to consider gas
2 supply and terminal use agreements arising from ENSTAR's use of an LNG import
3 facility's services, and we are not barred by AS 42.05.711(v) from doing so.

4 *Termination Date for the \$4.6 Million Regulatory Asset*

5 As an initial matter, in TA350-4, ENSTAR does not appear to request it be
6 able to continue to accrue future costs associated with its development plans in the
7 regulatory asset authorized by Order U-22-090(2).¹⁴² Thus our Question 2, asking if the
8 regulatory asset authorized by Order U-22-090(2) should be capped as of
9 December 17, 2024, seems to be answered by ENSTAR's TA request. However,
10 ENSTAR's briefing still suggests the regulatory asset should remain open to include
11 additional accrued costs.

12 ENSTAR does this by pointing to language in Order U-22-090(2) which says
13 the regulatory asset will be allowed "to accumulate and defer the *costs associated with*
14 *studying and securing* long term gas supplies." Because ENSTAR has not yet *secured* a
15 long-term gas supply, it argues it should still be allowed to include costs in the regulatory
16 asset we previously approved.¹⁴³

17
18
19 ¹⁴¹161 FERC ¶ 61,043 at P. 53 (2017) ("State utility regulators must approve any
20 expenditures by state-regulated utilities. We disagree with commenters who suggest that
21 once the Commission has made a determination in this proceeding, state regulators
22 cannot effectively review the expenditures of utilities that they regulate. In fact, any
23 attempt by the Commission to look behind the precedent agreements in this proceeding
24 might infringe upon the role of state regulators in determining the prudence of
25 expenditures by the utilities that they regulate. . . . Issues related to a utility's ability to
26 recover costs associated with its decision to subscribe for service . . . involve matters to
be determined by the relevant state utility commissions; those concerns are beyond the
Commission's jurisdiction.").

¹⁴²ENSTAR instead says it will remove "[t]he balance accumulated under the
previously approved regulatory asset and corresponding carrying costs" and record them
"as a new cost element in ENSTAR's GCBA. The costs that ENSTAR anticipates
incurring going forward (Future Costs) will be included in the same cost element in
ENSTAR's annual GCA calculations." TA350-4 at 3.

¹⁴³ENSTAR Opening Brief at 15.

1 We disagree. We approved the regulatory asset in Order U-22-090(2)
2 based on ENSTAR's participation in a "multiparty working group" that was studying
3 available choices to meet long term gas supplies. By its own admission, as of
4 December 17, 2024, ENSTAR has signed an exclusivity agreement with Glenfarne. It
5 has chosen to partner with Glenfarne to pursue this project.¹⁴⁴

6 ENSTAR's participation in this multiparty working group was also an
7 important consideration for us in allowing the regulatory asset we approved in
8 Order U-22-090(2). As we stated, "We also find mitigating that ENSTAR's costs are part
9 of a multiparty working group and therefore *are not entirely within ENSTAR's control*."¹⁴⁵
10 This is no longer the case. The multiparty mitigation governor we relied on in Order
11 U-22-090(2) no longer exists. We therefore terminate the regulatory asset authorized by
12 Order U-22-090(2) effective December 17, 2024.

13 GCA Recovery Request for \$4.6 Million Regulatory Asset

14 In Questions 4 and 5 listed in Order U-25-004(1), we asked whether it would
15 be appropriate to allow recovery of the \$4.6 million regulatory asset through ENSTAR's
16 GCA given our language in Order U-22-090(2), and whether the parties could identify
17 precedent where we have allowed a regulatory asset to be recovered via a GCA or a
18 COPA.

19 ENSTAR and the other Railbelt electric utility parties first point to language
20 in Order U-22-090(2) where we state our review of the regulatory asset costs will occur
21 in a "ratemaking proceeding" and that ENSTAR's GCA is a "rate" as defined by
22 AS 42.05.990(7).¹⁴⁶ While we agree that the term "rate" is defined in the statute
23 expansively, we disagree it was our intent in Order U-22-090(2) to review ENSTAR's
24 regulatory asset costs in anything other than a rate case. We noted in our order that

25 ¹⁴⁴TA350-4 at 2.

26 ¹⁴⁵Order U-22-090(2) at 6 (emphasis added).

¹⁴⁶ENSTAR Opening Brief at 18.

1 ENSTAR would need to “meet its evidentiary burden regarding the necessity and
2 prudence of costs, carrying costs, or appropriate amortization periods.”¹⁴⁷ GCA filings
3 are not reviewed in a comprehensive manner. The GCA and COPA adjustment clause
4 mechanisms are a streamlined review process designed primarily to accommodate
5 variable fuel costs which are easily verifiable. As we stated in a recent order:

6 Though there may be situations where more prompt recovery of costs provides
7 a benefit to cooperative customers, that does not provide a broad justification
8 for a waiver of 3 AAC 52.502(a) requirements or for cost recovery through the
COPA. Such a justification would allow the inclusion of a potentially unlimited
number of operational expenses incurred by a utility.¹⁴⁸

9 ENSTAR does attempt to show these regulatory asset costs have an
10 adequate linkage with variable fuel costs permitted for recovery through a GCA or a
11 COPA. While first stating the costs included in the \$4.6 million regulatory asset pertain
12 to “studying and securing long term gas supply,”¹⁴⁹ it subsequently adds they are “related
13 to the importation of LNG to the Cook Inlet” and that this “unprecedented event”
14 represents “unusual fuel costs” which should be granted GCA treatment.¹⁵⁰ However, as
15 RAPA points out, these costs are operating expenses; they do not relate to changes in
16 fuel supply as defined in 3 AAC 52.519(a)(1).¹⁵¹

17 We agree. The costs included in the \$4.6 million regulatory asset are
18 operating expenses. They are not commodity costs contemplated by 3 AAC 52.519(a)(1)
19 for inclusion in GCA recovery.

20 Nor does the precedent ENSTAR cites show its request for GCA recovery
21 is proper. ENSTAR first cites Order U-86-008(6), but this order rejected GCA recovery

22 ¹⁴⁷Order U-22-090(2) at 6

23 ¹⁴⁸Letter Order No. L2500075, dated March 4, 2025, at 2.

24 ¹⁴⁹TA350-4 at 3.

25 ¹⁵⁰ENSTAR Reply at 19–20.

26 ¹⁵¹3 AAC 52.519(a)(1) reads:

“adjustment clause” means a mechanism designed to recover changes in gas,
fuel, and purchased power expenses; “adjustment clause” includes COPAs
and GCAs[.]

1 of royalty settlement costs baked into a gas supply contract, finding them ill-suited for
2 GCA inclusion:

3 The Commission must now determine the appropriate mechanism to use in
4 collecting the settlement amount from ENSTAR's ratepayers. Because the
5 Commission has determined that the ratepayers should not pay interest costs,
6 the PGCA [Purchased Gas Cost Adjustment] cannot be used. Even if the
7 Commission were to adopt ENSTAR's position that the costs should be
8 recovered with interest, the PGCA would not be an appropriate vehicle for
9 recovery. The PGCA balancing account is based on the difference between
10 estimated consumption and actual consumption and the difference between
11 estimated unit cost and actual unit cost of the gas purchased. As previously
12 discussed, *the royalty settlement amount is not tied to specific gas purchases,*
13 *either as to quantity or as to unit cost. It is simply inappropriate to try to fit this*
14 *unusual expense into the scheme of the PGCA.*¹⁵²

15 We reached the same conclusion in another ENSTAR order. In Order
16 U-01-152(4), we considered ENSTAR's request for GCA recovery of legal and consulting
17 costs incurred in obtaining approval of a gas supply agreement with Unocal in Docket
18 U-01-007. We stated:

19 As a matter of precedent, in Order U-86-8(6), the Commission stated that
20 customers should pay for legal and consulting costs associated with the cost
21 of gas; however, *the legal and consulting costs are not a commodity cost and*
22 *should be treated differently than other gas costs.* The Commission added
23 that including such costs in ENSTAR's GCA would result in ENSTAR collecting
24 interest from ratepayers on the legal and consulting expenses. The
25 Commission found that it was inappropriate for customers to pay interest costs,
26 *because the purpose of the GCA is to balance the difference between the*
estimated and actual costs of gas. This case is virtually identical and ENSTAR
has not provided any justification to convince us to violate that precedent and
grant ENSTAR's request to include the legal and consulting expenses in its
GCA.¹⁵³

ENSTAR's request for GCA recovery has additional fatal defects. 3 AAC
52.502(a) has three gatekeeper requirements for GCA consideration:

- Cost elements included in an adjustment clause must be
- (1) subject to change at a rate that would cause financial harm to the utility if the costs were recovered exclusively through base rates;
 - (2) beyond the control for the utility; and

¹⁵²Order U-86-008(6) at 14 (emphasis added).

¹⁵³Order U-01-152(4) at 5 (emphasis added).

1 (3) easily verifiable.

2 It is difficult to discern how accumulated regulatory asset costs *already*
3 *incurred* can meet the requirements of subsection (a)(1). Past incurred costs already
4 accumulated are not “changing,” a requirement of subsection (a)(1). Nor can ENSTAR
5 legitimately claim depriving it of GCA treatment for these regulatory asset costs will cause
6 it financial harm. As we stated just last year in Order U-22-081(14) at 34:

7 We acknowledge that there is a looming gas shortage in the Cook Inlet and
8 ENSTAR may have to spend or borrow significant funds in the future to secure
9 a gas supply. Meanwhile, ENSTAR’s current ROE has been steadily earning
10 sufficient revenue and maintaining healthy equity for the company. We find
11 that ENSTAR’s current equity position will be beneficial for ENSTAR if those
12 investments have to be made.¹⁵⁴

13 No party has cited any relevant precedent supporting ENSTAR’s request.
14 Nor have we found any precedent where we have allowed non-fuel related regulatory
15 asset costs to flow through a GCA or COPA.¹⁵⁵

16 For the above reasons, we deny ENSTAR’s request. ENSTAR may seek
17 to address this \$4.6 million regulatory asset and an appropriate amortization period in its
18 next rate case.

19
20 ¹⁵⁴This conclusion is further supported by our decision in Order U-22-032(6)/
21 U-22-033(6)) at 39, where ENSTAR was acquired by TriSummit: “We further find that
22 TriSummit Utilities Inc.’s past financial performance and demonstrated financial
23 resources are sufficient to provide financial support to ENSTAR Natural Gas
24 Company, LLC; Alaska Pipeline Company, LLC; and CINGSA, as may be required to
25 fund investment in new facilities and costs associated with unexpected occurrences.”

26 ¹⁵⁵The only other precedent cited was HEA’s reference to Order U-06-140(1), in
HEA Opening Brief at 11. This order does not support ENSTAR’s request. In TA260-32,
HEA requested authority to include prepayment of a fuel supply obligation in the
computation of its WPCRA. The accounting treatment for fuel credits received was based
on amortized savings used to reduce purchase power expenses and the savings were
passed through to HEA’s members via its WPCRA. In TA350-4, however, ENSTAR’s
development costs are not fuel costs, nor are they credits against fuel costs incurred by
ENSTAR’s ratepayers which could theoretically flow through the GCA.

1 GCA Recovery Request for Development Costs

2 In TA350-4, ENSTAR requests GCA recovery for its own development
3 costs, and for those of the LNG import facility developer. For the Developer’s Costs,
4 these will be requested only if the LNG Project is terminated at which point ENSTAR will
5 be required to reimburse the Developer’s Costs in a lump sum.¹⁵⁶

6 ENSTAR’s TA350-4 identifies the types of costs it and the developer will
7 incur throughout the development phase as falling into three buckets: project agreements,
8 engineering, and permitting. Each category generically identifies the types of activities
9 that will occur, but in general, they can be characterized as legal, contracting, and labor
10 costs associated with each development phase activity.¹⁵⁷

11 ENSTAR’s opening brief provides additional detail. It explains project
12 agreements costs will consist of “legal and consulting fees required to vet the
13 agreements.” Engineering costs will consist of its labor to “finalize the commercial
14 agreements” and provide “project management oversight of the developer’s activities.”
15 And permitting costs will “revolve around providing information on ENSTAR’s connecting
16 facilities, needs, and customers.”¹⁵⁸

17 Both RAPA and JLP/RSD claim these costs are inappropriate for GCA
18 recovery. RAPA points to ENSTAR’s own language in TA350-4, saying these costs
19 “relate to studying and securing a long-term gas supply,” and not to the “underlying cost
20 of gas” as evidence showing the costs do not meet the requirements of
21 3 AAC 52.519(a)(1), and it argues additional development costs of \$5 million cannot meet
22 the financial harm showing required under 3 AAC 52.502(a)(1).¹⁵⁹ JLP/RSD argue the
23 information provided by ENSTAR about these costs is “scant” and “wholly insufficient to
24

25 ¹⁵⁶TA350-4 at 3–4.

26 ¹⁵⁷TA350-4 at 4–6.

¹⁵⁸ENSTAR Opening Brief at 12–13.

¹⁵⁹RAPA Opening Brief at 21; RAPA Reply at 12–14.

1 determine whether the costs are properly recoverable at all, let alone through a [GCA].”¹⁶⁰
2 Because of this ambiguity, JLP/RSD also express concern that the development costs
3 requested could include non-jurisdictional expenses which require exclusion from rates.
4 As JLP/RSD put it, “[t]his Commission must determine what, if any, of these costs are
5 properly recoverable, which is a challenging task in light of the dearth of details provided
6 by ENSTAR.”¹⁶¹

7 For many of the same reasons we rejected GCA treatment for ENSTAR’s
8 \$4.6 million regulatory asset, we deny ENSTAR’s request for GCA treatment of its
9 development costs, and the lump sum payment due to the developer under Scenario 2 if
10 the Project is terminated.

11 First, the costs ENSTAR describes as its development costs, and for those
12 of the developer, are non-fuel-related operating expenses. They are not fuel related
13 expenses of the sort identified by 3 AAC 52.519(a)(1). And the same precedent cited
14 earlier, Orders U-86-008(6) and U-01-152(4), both contradict ENSTAR’s GCA recovery
15 request.

16 Second, allowing GCA treatment of ENSTAR’s development costs would
17 deprive us of a meaningful ability to review at least a portion of the development costs for
18 prudence. Under ENSTAR’s GCA, it makes quarterly filings, but its GCA is adjusted
19 annually.¹⁶² ENSTAR’s development costs would therefore be included annually in its
20 GCA. However, TA350-4 shows a multi-year timeline for the LNG Project, with
21 development costs continuing to accrue for GCA consideration through at least 2026. If

22 ¹⁶⁰JLP/RSD Reply at 2.

23 ¹⁶¹JLP/RSD Reply at 5–10.

24 ¹⁶²Under ENSTAR’s tariff, ENSTAR is required to file its GCA as a tariff filing on or
25 before July 1 of each year. The annual GCA filing reflects the weighted average cost of
26 gas for the ensuing 12 months and includes the March 31 GCBA balance. Although
ENSTAR is required to file the GCA on an annual basis, ENSTAR is also required to file
the GCBA report on a quarterly basis fifteen days after the end of each quarter. The
GCBA filings are informational, and the costs included in the GCBA filings flow into the
annual GCA filing. See ENSTAR’s Tariff Sheets Nos. 128 and 130.

1 the LNG Project is terminated downstream from when development costs have already
2 been rolled through ENSTAR's GCA, there would be no meaningful remedy for
3 ratepayers who have already paid rates which include development costs if they are
4 subsequently ruled imprudent. Requiring a refund of these imprudently incurred costs
5 would violate the rule against retroactive ratemaking.¹⁶³

6 Third, the development costs identified do not meet the requirements of
7 3 AAC 52.502(a)(1). As we addressed above for ENSTAR's \$4.6 million regulatory asset,
8 the amount at issue is inadequate to meet a financial harm threshold given ENSTAR's
9 enhanced 11.875% ROE and the financial strength of its parent TriSummit. Regarding
10 the Developer's Costs, since they will be requested as a lump sum payment after all costs
11 have accrued, there is no variability or change implicated that would meet the
12 requirements of subsection (a)(1).

13 Fourth, we will require a more robust review of the LNG Project
14 development costs than that which generally happens in our review of GCA filings.¹⁶⁴
15 While TA350-4 provides broad cost generalizations of what ENSTAR believes its future
16 development costs will be,¹⁶⁵ JLP/RSD are correct in pointing out that we have no *details*
17 about the development costs ENSTAR proposes to roll through its GCA other than
18 ENSTAR's broad characterizations of what these costs will or will not cover.¹⁶⁶ We do
19 not currently know the terms of any contracts that will ultimately be presented, what legal

21 ¹⁶³See *MEA v. Chugach Elec. Ass'n*, 53 P.3d 578, 585 (Alaska 2002) (barring a
22 recovery of a COPA overpayment because requiring it would violate the rule against
23 retroactive ratemaking).

24 ¹⁶⁴The abbreviated nature of the Commission's review of GCA or COPA filings was
25 discussed in *MEA v. Chugach*, 53 P.3d at 585. The danger of agreeing to use the GCA
26 process for ENSTAR's proposed development costs is illustrated in this decision. Since
the Commission's COPA review was abbreviated, mistakes were made which could not
be undone because of the rule against retroactive ratemaking.

¹⁶⁵TA350-4 at 3–6.

¹⁶⁶See, e.g., ENSTAR Reply at 9 ("The costs that ENSTAR proposes to recover
through TA350-4 are all attributable to intrastate activities under the Commission's
jurisdiction.")

1 or consulting fees we will see, what potential affiliated transactions we may need to
2 adjudicate, or whether any of these costs will be non-jurisdictional. ENSTAR's summary
3 overview of these projected costs is simply insufficient to justify the ratemaking treatment
4 it requests.¹⁶⁷ We will require these costs be reviewed in a rate case proceeding to
5 ensure non-jurisdictional costs are excluded from rates, in addition to assessing the
6 prudence and reasonableness of costs within our jurisdiction for inclusion in rates.

7 Allocation of Risk

8 In Question 3, we asked why ENSTAR's ratepayers should assume all risk
9 associated with ENSTAR's LNG Project. We observed our orders generating ENSTAR's
10 existing ROE have been enhanced, designed to compensate ENSTAR for the business
11 risk it now faces—a shortage of natural gas. We said so in Order U-16-066(19)¹⁶⁸ at 50,
12 and again just one year ago in Order U-22-081(14) at 34.

13 Despite our past willingness to compensate ENSTAR for this business risk
14 in its revenue requirements, ENSTAR suggests there is no justification to allocate any
15 risk or LNG development costs to its shareholders. ENSTAR claims it has no assets
16 associated with its gas purchases upon which a return can be generated, implying its
17 LNG development costs are somehow untethered from any risk allocation analysis.
18 ENSTAR also argues Order U-22-081(14) does not compel a contrary conclusion
19 because we “explicitly did not include lack of a gas supply, and the corresponding need
20 to import LNG, as a risk factor that would increase ENSTAR's relative risk.” ENSTAR
21 instead focuses on our discussion in Order U-22-081(14) of why our creation of a
22 regulatory asset for ENSTAR in Order U-22-090(2) helps buffer ENSTAR from some gas

23 _____
24 ¹⁶⁷See *Jager v. State*, 537 P.2d 1100, 1113-14 (Alaska 1975) (“The commission
25 may not, however, defer to bald assertions by management. This is so particularly when
26 more compelling evidence, in the form of economic and statistical analyses and
comparisons of the type which can be committed to record and be available for analysis
by the commission and by a reviewing court, can be developed at reasonable cost.”).

¹⁶⁸Order U-16-066(19), *Order Resolving Revenue Requirement and Cost-of-
Service Issues and Requiring Filings*, dated September 22, 2017 (Order U-16-066(19)).

1 supply risk by “shift[ing] the risk and cost to future ratepayers,”¹⁶⁹ and that this deprived
2 it of a risk factor which could have enhanced its ROE.¹⁷⁰

3 We disagree our decision to create a regulatory asset in Order U-22-090(2)
4 is dispositive on this issue. However, we need not delve too deep into this argument’s
5 circularity because ENSTAR does not address the language in our ROE determination
6 where we tied ENSTAR’s awarded ROE to the looming Cook Inlet natural gas shortfall:

7 We acknowledge that there is a looming gas shortage in the Cook Inlet and
8 ENSTAR may have to spend or borrow significant funds in the future to secure
9 a gas supply. Meanwhile, ENSTAR’s current ROE has been steadily earning
10 sufficient revenue and maintaining healthy equity for the company. We find
11 that ENSTAR’s current equity position will be beneficial for ENSTAR if those
12 investments have to be made.¹⁷¹

13 We also find unpersuasive ENSTAR’s claim of immunity from any risk
14 allocation because it has no assets associated with its gas purchases upon which a return
15 can be generated. On this point, RAPA noted, “[t]he fact that ENSTAR will not earn a
16 return on this particular investment does not change the fact that it *currently* earns a return
17 on its rate base that compensates it for the purported risk posed by the situation in Cook
18 Inlet.¹⁷² We agree.

19 We made clear in Order U-16-066(19) and Order U-22-081(14) that
20 ENSTAR’s authorized ROE was providing it revenue designed to help address the
21 problem it is now seeking to cure, and at 11.875%, it currently has the highest ROE of
22 any rate regulated investor owned utility in the state.¹⁷³ It would be unreasonable for us
23 to require ratepayers to fully compensate ENSTAR for this business risk in rates, and
24 then require ratepayers again to fully absorb all LNG development costs without any cost

25 ¹⁶⁹Order U-22-081(14) at 33.

26 ¹⁷⁰ENSTAR Opening Brief at 16–17.

¹⁷¹Order U-22-081(14) at 34.

¹⁷²RAPA Reply at 11.

¹⁷³RAPA Opening Brief at 18.

1 allocation to ENSTAR when its shareholders have already been compensated for this
2 business risk.

3 Applicability of Carrying Costs

4 In TA350-4, ENSTAR requests to be allowed to recover carrying costs on
5 its \$4.6 million regulatory asset. It sets an interest rate at 5.34% based on its long-term
6 debt.¹⁷⁴ We note that no authority was cited in support of this request, and we did not
7 request briefing on this issue. Because we are requiring ENSTAR to address its
8 \$4.6 million regulatory asset in its next rate case, we will address the appropriateness of
9 permitting the inclusion of carrying costs, interest, or a return on amortized regulatory
10 asset recovery, at that time.

11 But we note we have previously addressed this issue for ENSTAR. In Order
12 U-00-088(12), we addressed ENSTAR's request to create a regulatory asset including
13 several expenses.¹⁷⁵ ENSTAR also requested a return allowance on the amortized
14 balances. In denying this request, we recognized regulatory asset creation was an
15 extraordinary remedy, but it did not carry with it an entitlement to a return, interest or
16 carrying costs because such an allowance would be inconsistent with ratemaking theory:

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¹⁷⁴TA350-4 at 4.

26 ¹⁷⁵Order U-00-088(12), *Order Establishing Revenue Requirement, Requiring Filings, Scheduling Prehearing Conference, and Affirming Electronic Rulings*, dated August 8, 2002 (Order U-00-088(12)).

1 In the case of extraordinary or nonrecurring expenses, the appropriate
2 adjustment to the revenue requirement is either to remove the expense, or
3 where the utility proves benefit to future ratepayers, to amortize it over a
4 reasonable period.¹⁷⁶ ENSTAR's proposed regulatory asset treatment, in
5 contrast, treats a cost it incurred previously as an investment on which it should
6 both recover and earn a return from future ratepayers.¹⁷⁷

7 We are aware that Order U-22-090(2), which authorized creation of the \$4.6
8 million regulatory asset, references carrying costs. But we did not address whether they
9 would be authorized, instead stating the issue, along with all others would be investigated
10 when we reviewed ENSTAR's request to include them in rates. Our order here does not
11 disturb that decision.

12 *Application of AS 42.05.441(b) to Scenario 2 Development Costs*

13 All parties other than JLP/RSD seem to agree that AS 42.05.441(b) would
14 not apply to bar development costs ENSTAR incurs if the LNG Project is cancelled or
15 otherwise terminated. But JLP/RSD suggest the "used and useful" requirement of the
16 statute does apply because this protects ratepayers from "bearing the costs of the exact
17 type of speculative investment that ENSTAR seeks to recover."¹⁷⁸

18 We disagree that the statute is applicable. AS 42.05.441(b) is a rate base
19 valuation statute, requiring plant in service be "used and useful" in providing a utility-
20 related benefit. Without this linkage, neither depreciation expense nor a return on
21 investment can be allowed on this plant.

22 But under Scenario 2, the development costs at issue are operating
23 expenses incurred in pursuit of a terminated project. Since no LNG import facility will be

24 ¹⁷⁶See 3 AAC 48.820(42) defining a "normalized test year" as "a historical test-year
25 adjusted to reflect the effect of known and measurable changes and to delete or average
26 the effect of unusual or nonrecurring events, for the purpose of determining a test year
which is representative of normal operations in the immediate future." Normalized test
year data includes supportive information required by 3 AAC 48.275(a), which is used to
establish a utility's revenue requirement.

¹⁷⁷Order U-00-088(12) at 24. Other ENSTAR orders reach the same conclusion
in analogous circumstances. See Order U-86-008(6) at 13 and Order U-01-152(4) at 5-6.

¹⁷⁸JLP/RSD Opening Brief at 16.

1 built under Scenario 2, there is no plant at issue for purposes of a subsection .441(b)
2 review.

3 While AS 42.05.441(b) does not apply by its own terms to an abandoned
4 project, Chugach and RAPA note that there is authority from other jurisdictions that
5 addresses whether it is appropriate to include costs of an abandoned project in rates.
6 This authority cuts both ways; some jurisdictions have denied recovery where others have
7 allowed it after rate case review and application of an appropriate amortization period.¹⁷⁹
8 As RAPA notes, “the decision of whether to allow a utility to recover costs associated with
9 cancelled or abandoned projects must be made on a case-by-case basis where a
10 determination of the prudence of the initial investment can be made, as well as the
11 prudence of the ultimate decision to abandon the project.”¹⁸⁰

12 In evaluating this issue, we agree with MEA’s characterization that in
13 looking to import LNG into the Cook Inlet, we are addressing “an unprecedented event in
14 Alaskan history.”¹⁸¹ We also recognize that ENSTAR’s plan to source gas supplies from
15 outside Alaska can be viewed as a fundamental change to its business practice. Under

17 ¹⁷⁹See Chugach Reply at 9 & n.37 (citing *Nat. Gas Pipeline Co. of Am.*, 27 FERC
18 ¶ 61,201, at ¶ 61,379 (1984) (disallowing the costs for three abandoned gas supply
19 projects, where the costs were “found to be speculative and uncertain, remote in time,
20 and without benefit to ratepayers. These projects have been held to constitute risks which
21 should properly be borne by shareholders rather than ratepayers and which should be
22 compensated by means of the pipeline’s allowed rate of return rather than by means of a
23 specific allowance in the cost of service.”)).

24 ¹⁸⁰RAPA Opening Brief at 25–28.

25 ¹⁸¹MEA Opening Brief at 4. MEA also analogizes the permissibility of including
26 terminated project costs in rates to our prior decisions where we have allowed acquisition
adjustments. *Id.* at 3. An acquisition adjustment occurs when a utility is purchased for
an amount beyond net book value. Our general rule is to not allow an acquisition
adjustment in rates. An exception to this general rule may be allowed, but only where a
utility demonstrates that ratepayers will receive a specific tangible benefit in an amount
at least equal to the cost of the acquisition adjustment. See Order U-02-013(7)/
U-02-014(7)/U-02-015(7), *Order Affirming Electronic Ruling Vacating Hearing, Accepting
Stipulation, Subject to Condition, and Cancelling Hearing*, dated March 19, 2003, at 7.
We do not agree our standard for approval of acquisition adjustments is analogous.
Under Scenario 2, the LNG Project will be terminated. No ratepayer benefit will result
from a terminated project that does not address ENSTAR’s gas supply shortfall.

1 these unique circumstances we do not agree that an ultimate decision to terminate this
2 project should, by itself, disenfranchise ENSTAR from pursuing its Scenario 2
3 development costs.¹⁸² We hold that ENSTAR may do so, under the procedure we
4 describe below. We will review whether these costs are jurisdictional, prudently incurred,
5 reasonable, and select an appropriate amortization period when the development costs
6 are ultimately presented in a rate case for our review.

7 Creation of a New Regulatory Asset

8 ENSTAR says in TA350-4 that it needs an “assurance of timely recovery of
9 third-party costs to secure the funding, security and resources required” to move forward
10 with its project.¹⁸³ But we must also balance ENSTAR’s request with our statutory duty
11 to protect ratepayers by ensuring that rates imposed are just and reasonable.¹⁸⁴ In order
12 to do so, we will allow ENSTAR to create a new regulatory asset to record third-party
13 development costs identified in TA350-4.

14 As we have stated earlier, allowing regulatory asset creation is an
15 extraordinary remedy. We have permitted for-profit utilities to create regulatory assets
16 when operating or maintenance costs, which would otherwise be expensed, are
17 significant and occur because of unusual circumstances not representative of normal
18 operations.¹⁸⁵

19 We believe those circumstances exist here. Incurring substantial costs in
20 anticipation of LNG imports unquestionably represents an unusual circumstance.
21 ENSTAR’s projected participation in the development of a greenfield LNG Project is not

22 ¹⁸²We generally exclude expenses that are not associated with utility service or
23 provide a utility-related benefit from rates. See, e.g., Order U-00-088(12) at 6 &
24 Appendix A, Schedule 4, Notes 3–4. While costs incurred for a terminated project would
25 ordinarily fall within this category of excluded expenses, we recognize the unusual and
26 extraordinary circumstances presented here warrant a limited exception to this general
rule.

¹⁸³TA350-4 at 8.

¹⁸⁴AS 42.05.381(a); AS 42.05.431(a).

¹⁸⁵Order U-22-090(2) at 3.

1 representative of its normal operations, and the LNG Project's anticipated development
2 costs are significant, as outlined in TA350-4.

3 But we will not provide a blank check. Caps will be imposed on this
4 regulatory asset's costs recognizing, in part, the amounts identified in TA350-4,
5 Attachment D. For Developer Costs, we cap permissible regulatory asset costs at
6 \$42.3 million. ENSTAR's regulatory asset development costs are capped at
7 \$4,758,750.¹⁸⁶ If development costs exceed these caps, the additional costs will be borne
8 by ENSTAR's shareholders or by the developer.

9 In reaching this decision, we find instructive a similar cap we imposed on
10 projected utility development plans in Order U-97-245(1), where Alaska Electric Light &
11 Power Company (AEL&P) planned to construct a submarine cable, projecting its costs at
12 \$101 million.¹⁸⁷ We stated:

13 Because the full cost of the submarine cable will not be known until installation
14 is complete, which will occur after the bond sales, the Commission would like
15 assurances that the total project cost, including the submarine cables, will not
16 exceed \$101 million. If costs do escalate beyond \$101 million, the
17 Commission will not allow these costs to be passed on to the ratepayers. Any
18 additional costs will be borne by the Federal Government, AIDEA, or AEL&P.
19 During AEL&P's rate case, the Commission will closely examine the costs
20 associated with installing the submarine cable to determine if they are
21 reasonable and allowable in rate base.¹⁸⁸

22 We are addressing a similar situation here, requiring we balance ratepayer
23 protections with ENSTAR's plans to procure LNG. As was the case for AEL&P, we will
24 not know what the full development costs will be until ENSTAR and the developer reach
25 a decision point on proceeding to construction. As our predecessor the Alaska Public
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23 ¹⁸⁶These caps were determined by using the 11.875% ROE, granted to ENSTAR
24 in its revenue requirement as compensation for its gas supply business risk, as an offset
25 to the development cost projections for ENSTAR (\$5.4 million) and the Developer (\$48
26 million) identified in TA350-4, Attachment D.

25 ¹⁸⁷Order U-97-245(1), *Order Approving Power Sales Agreement, Subject to*
26 *Conditions; Approving Application and Related Hatchery Electric Service Agreement,*
Subject to Conditions; and Requiring Filing, dated June 24, 1998 (Order U-97-245(1)).

¹⁸⁸Order U-97-245(1) at 7.

1 Utilities Commission required, we also require ratepayer protections be in place if
2 development costs exceed the ceiling we impose in this order.

3 By allowing creation of a new regulatory asset to be reviewed in a
4 subsequent rate case, we are providing ENSTAR a fair and balanced mechanism to
5 address this LNG Project's development costs. ENSTAR can seek interim rate relief
6 while its rate case proceeds investigating these costs, providing it a prompt remedy while
7 we concurrently protect ratepayers from any overpayment.

8 We emphasize the development cost totals we will consider for inclusion in
9 rates represent a substantial risk mitigator for ENSTAR.¹⁸⁹ While the caps provide
10 assurance for ENSTAR that we will consider costs up to these ceilings, provided they are
11 reasonable, jurisdictional and prudently incurred, the caps also recognize ENSTAR's
12 shareholders bear some responsibility to shoulder development cost risks for which they
13 have already been compensated.

14 We require the following conditions on creation of this regulatory asset:

- 15 (1) ENSTAR may only include third-party costs in the asset, and it cannot include
16 internal labor or overhead;
- 17 (2) Development costs accumulated in the regulatory asset are capped at
18 \$4,758,750 for ENSTAR, and \$42.3 million for the developer;
- 19 (3) ENSTAR must submit informational filings quarterly about its regulatory asset
20 development costs including:
 - 21 a. a balance of its incurred costs as well as a narrative statement detailing the
22 progress of the LNG Project's development; and
 - 23 b. a summary list of all incurred costs with each quarterly informational filing.
- 24 (4) Our approval of the creation of a new regulatory asset does not include amounts
25 allocated to future capital projects or reimbursed by third parties;
- 26 (5) Our decision does not shift ENSTAR's evidentiary burden to show the costs
included in the regulatory asset are within our jurisdiction, were necessary,
reasonable and prudent, and an appropriate amortization period be established;
and

¹⁸⁹Rather than imposing a direct cost allocation percentage to ENSTAR's
shareholders for each development dollar spent or excluding these costs entirely if the
Project is terminated, we have instead applied the development cost ceilings discussed
above based on the unique circumstances presented in this docket.

1 (6) ENSTAR's costs accumulated in this new regulatory asset, and any other issue
2 pertaining to this regulatory asset, may only be reviewed for inclusion in rates in
3 a rate case proceeding.

4 Denying TA350-4

5 We deny TA350-4. We find that the regulatory asset approved in Order
6 U-22-090(2) closed when ENSTAR signed an exclusivity agreement with Glenfarne on
7 December 17, 2024. In its last rate case, ENSTAR agreed to file a rate case in 2025 or
8 in 2026 based on a 2024 or 2025 test year, respectively.¹⁹⁰ ENSTAR may seek to recover
9 the costs of the \$4.6 million regulatory asset in that rate case.

10 We allow ENSTAR to create a new regulatory asset to defer costs up to
11 \$4,758,750 for its development costs, and \$42.3 million for the developer's Scenario 2
12 development costs as described in the body of this order. ENSTAR may seek to put this
13 regulatory asset into base rates in a future rate case after demonstrating the costs are
14 reasonable, jurisdictional, and prudently incurred, and after demonstrating an appropriate
15 amortization period. Our approval does not include amounts for internal labor or
16 overhead, costs allocated to future capital projects, or costs reimbursed by third parties.
17 Our decision does not shift ENSTAR's evidentiary burden to demonstrate the necessity,
18 reasonableness and prudence of costs, or appropriate amortization periods. We will
19 investigate these, and any other issues required when ENSTAR requests to include these
20 costs in the calculation of rates in a rate case proceeding.

21 Requiring Filings

22 Until the new regulatory asset approved in this order is fully and finally
23 addressed in a rate case proceeding, we require ENSTAR to file information pertaining
24 to its regulatory asset as detailed in the body of this order.

25
26 ¹⁹⁰Order U-22-081(11), *Order Accepting Partial Stipulation, Rescheduling Hearing, Denying Motion for Expedited Consideration, Amending Docket Caption, and Redesignating Commission Panel*, dated October 11, 2023, Appendix at 8.

1 Motions

2 Both RAPA and ENSTAR filed motions for confidential discovery orders on
3 March 28, 2025. RAPA also filed a motion for expedited consideration. Because this is
4 a final order fully addressing TA350-4, we find these motions moot.

5 Vacating Remaining Procedural Schedule and Hearing Dates

6 As this is a final order, we vacate the remainder of the procedural schedule,
7 which consequently results in the vacation of the hearing dates established in this docket
8 adopted by Order U-25-004(3).

9 Administrative Law Judge

10 The chair reappoints an administrative law judge for this docket. Under
11 AS 42.04.070(b), the chair appoints Administrative Law Judge Patrick S. Sheridan to
12 facilitate conduct of the docket. Orders issued by the administrative law judge will be
13 considered orders of the Commission for purposes of petitions for reconsideration.

14 Final Order

15 “Case law from the Alaska Supreme Court is clear that there is no statutory
16 or procedural due process right to an oral hearing in the absence of a factual dispute.”¹⁹¹
17 Additionally, “some kinds of disputes, such as legal and policy arguments, are addressed
18 more efficiently through written statements. Written statements, as well as oral testimony,
19 provide . . . an opportunity to be heard and have been held to meet the statutory
20 requirement of a hearing.”¹⁹² This standard has been met here.

21 We find that this order settles all outstanding issues in this docket and meets
22 our timeline to issue a final order under AS 42.05.175.

23 _____
24 ¹⁹¹Order U-16-069(7), *Order Affirming Initial Impression, Withdrawing Carrier of*
25 *Last Resort Status, and Terminating Carrier of Last Resort Support*, dated May 24, 2017
(citing *Church v. Dep’t of Revenue*, 973 P.2d 1125, 1129 (Alaska 1999); *Smith v. Dep’t*
of Revenue, Child Support Enforcement Div., 790 P.2d 1352, 1353 (Alaska 1990)).

26 ¹⁹²Order U-01-129(2)/U-01-130(2)/U-01-131(2), *Order Denying Petition for*
Reconsideration, dated December 18, 2001 (citing *Church v. State, Dep’t of Revenue* at
1129-30.).

1 This order constitutes the final decision in this proceeding. This decision
2 may be appealed within thirty days of this order in accordance with AS 22.10.020(d) and
3 the Alaska Rules of Court, Rules of Appellate Procedure, Rule 602(a)(2). In addition to
4 the appellate rights afforded by AS 22.10.020(d), a party has the right to file a petition for
5 reconsideration in accordance with 3 AAC 48.105. If such a petition is filed, the time
6 period for filing an appeal is then calculated in accordance with Alaska Rules of Court,
7 Rules of Appellate Procedure, Rule 602(a)(2).

8 **ORDER**

9 THE COMMISSION FURTHER ORDERS:

10 1. The regulatory asset authorized by Order U-22-090(2), *Order Granting*
11 *Petition to Create Regulatory Asset, Requiring Reporting, and Closing Docket*, dated
12 February 22, 2023, is closed effective December 17, 2024.

13 2. ENSTAR Natural Gas Company, LLC may create a regulatory asset to
14 defer up to \$4,758,750 of its own development costs, and \$42.3 million of the developer's
15 Scenario 2 development costs as described and subject to the conditions established in
16 the body of this order.

17 3. The tariff revision designated as TA350-4, filed January 28, 2025, by
18 ENSTAR Natural Gas Company, LLC, is denied as described in the body of this order.

19 4. The *Motion to Adopt Confidential Discovery Material Order*, filed
20 March 28, 2025, by ENSTAR Natural Gas Company, LLC is moot.

21 5. The *Office of the Attorney General's Motion for Entry of Proposed Order*
22 *Governing Confidential Discovery Material*, filed March 28, 2025, by the Office of the
23 Attorney General, Regulatory Affairs and Public Advocacy Section is moot.

24 6. The *Office of the Attorney General's Motion for Expedited Consideration*
25 *of Motion for Entry of Proposed Order Governing Confidential Discovery Materials*, filed
26 March 28, 2025, by the Office of the Attorney General, Regulatory Affairs and Public
Advocacy Section is moot.

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7. ENSTAR Natural Gas Company, LLC shall file informational filings quarterly as compliance filings into this docket, as described in the body of this order.

8. The procedural schedule that includes a hearing scheduled for August 21–26, 2025, adopted by Order U-25-004(3), *Order Adopting Procedural Schedule and Establishing Briefing Schedule*, dated February 18, 2025, is vacated.

9. Patrick S. Sheridan is appointed as the administrative law judge.
DATED AND EFFECTIVE at Anchorage, Alaska, this 22nd of April, 2025.

BY DIRECTION OF THE COMMISSION



Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
907-276-6222; TTY 1-800-770-8973

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 Consideration of Consumer Costs)
Arising from Utility Contracting with Liquefied)
Natural Gas Facilities)
_____)

Docket No. I-26-001

RESPONSE OF ENSTAR NATURAL GAS COMPANY, LLC
TO ORDER I-26-001(1)

In accordance with the Order Opening Docket, Requiring Filings, and Inviting Filings issued by the Regulatory Commission of Alaska (“Commission”) in the above-captioned proceeding on February 4, 2026 (“Order I-26-001(1)” or “Order”), ENSTAR Natural Gas Company, LLC (“ENSTAR” or “Company”)¹ respectfully submits this response (“Response”) addressing the questions raised and information requested in the Order. The potential for liquefied natural gas (“LNG”) resources is a critical issue for ENSTAR and the other Railbelt utilities, and the Company appreciates this opportunity to provide information to the Commission. The Company has used its best efforts to respond to the Commission’s questions and provide relevant documents in the time allowed, but emphasizes that potential LNG-related arrangements are still in flux and under negotiation,

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.

and much of the information responsive to the Commission’s inquiry is confidential, is commercially sensitive, and must not be disclosed publicly. Given the deadline for filing this response and the commercially sensitive nature of the information requested, ENSTAR is continuing to work to identify responsive documents and to ensure the Company is compliant with applicable notice, consent, and waiver provisions within the various confidentiality agreements it has entered into with third parties. Therefore, the Company will need to supplement this filing within the coming weeks. Additionally, ENSTAR welcomes any discussion or further inquiry into the process it undertook or its decision-making after the Commission has had a chance to digest the various materials submitted in this docket.

In Appendix A to this response, ENSTAR has provided a list of the various public and confidential attachments included with this filing.

BACKGROUND

With the issuance of Order I-26-001(1), the Commission opened an informational docket to gather information about potential LNG facilities from which ENSTAR and Chugach Electric Association, Inc. (“Chugach”) may propose to purchase LNG for gas supply. The Order requires ENSTAR and Chugach to complete four principal tasks:

- First, it directs them to file “all information they possess related to LNG import facilities through which they propose to purchase LNG, including the projected costs to be recovered through rates from their customers.”²
- Second, the Order requires ENSTAR and Chugach to file briefs addressing the Commission’s jurisdiction to “require utilities to coordinate their proposed use of any proposed LNG import facility to maximize efficiency and minimize costs

² Order I-26-001(1), *Order Opening Docket, Requiring Filings, and Inviting Filings*, dated Feb. 4, 2026, at 4.

to consumers,” or whether requiring this coordination is otherwise in the public interest.³

- Third, the Order instructs the parties to “provide specific questions they believe should be considered and a narrative response to those questions.”⁴
- Finally, the Order states that ENSTAR and Chugach should “provide any documents in their possession that would be responsive to these questions, as well as additional documents they believe the Commission should attempt to obtain from other sources that would be relevant to this inquiry.”⁵

The Commission also invited the Office of the Attorney General, Regulatory Affairs and Public Advocacy Section (“RAPA”) to file a brief addressing the jurisdictional issues raised in the Order.⁶ The Commission directed the parties to submit their filings by March 6, 2026.⁷

On February 27, 2026, in response to correspondence from Cook Inlet LNG, LLC (“Cook Inlet LNG”), the Commission issued a second order inviting Cook Inlet LNG to make a presentation on its proposed LNG import project during the Commission’s public meeting scheduled for March 11, 2026, or to file the information in this docket.⁸ The Commission also invited other members of the public to file briefs addressing the jurisdictional issues raised in Order I-26-001(1) and otherwise to file comments in this docket.⁹

³ *Id.*

⁴ *Id.*

⁵ *Id.*

⁶ *Id.*

⁷ *Id.*

⁸ Order I-26-001(2), *Order Inviting Presentation, Filings, and Comments*, dated Feb. 27, 2026, at 1-2.

⁹ *Id.* at 2.

ENSTAR appreciates this opportunity to provide information to the Commission and otherwise address questions regarding potential LNG import facilities in Alaska. As the Company has explained on many occasions in recent years, with the well-documented gas supply challenges in Cook Inlet, imports of LNG will be an essential component of ensuring that the Company can continue providing safe and reliable natural gas service to the thousands of Alaska homes and businesses throughout its service territory. As the Commission knows, ENSTAR has entered into an exclusivity agreement with Glenfarne Energy Transition, LLC (“Glenfarne”) for a potential solution developing and implementing an LNG import facility to be located on the Kenai Peninsula (“Glenfarne Project” or “Project”), and ENSTAR believes this opportunity represents the best LNG supply option for the Company and its customers. ENSTAR hopes this informational docket will help provide a foundational understanding as to why ENSTAR chose the Glenfarne Project as the appropriate path forward for the Company and its customers. ENSTAR’s response to this inquiry is solely related to the Glenfarne Project.

The Order also acknowledges that ENSTAR and Chugach may need to file information classified as confidential under 3 AAC 48.045(b), and that any such information should be filed consistent with the requirements of 3 AAC 48.045(a). While ENSTAR recognizes its obligation to submit confidential information in accordance with Commission requirements, the Company emphasizes that certain information relevant to the subject matter of this docket is confidential and extremely commercially sensitive. Among other material harms, disclosing this information publicly could give one or more participants in the natural gas and LNG markets significant competitive advantages over

other participants or inadvertently harm them, and ENSTAR itself could face liability for potential violations of confidentiality agreements. Accordingly, and concurrently with this filing, the Company is submitting a petition for confidential treatment in accordance with 3 AAC 48.045.

DISCUSSION

In the sections below, ENSTAR addresses the four topics the Commission directed the Company to address in Order I-26-001(1).

I. We require Chugach and ENSTAR to file in this docket all information they possess related to LNG import facilities through which they propose to purchase LNG, including the projected costs to be recovered through rates from their customers.

As a regulated utility with a mandate to provide service that is “reasonably continuous and without unreasonable disruption”¹⁰ to half of Alaska’s population, ENSTAR has undertaken a very deliberate process to evaluate potential gas supply arrangements, including LNG supply arrangements. In May 2022, ENSTAR, Chugach, Matanuska Electric Association, Inc. (“MEA”), Homer Electric Association, Inc. (“HEA”), Golden Valley Electric Association, Inc. (“GVEA”), and the Interior Gas Utility (“IGU”) formed a working group, with participation from the Alaska Department of Natural Resources (“DNR”) and the Alaska Energy Authority (“AEA”), to assess future gas supply needs and energy security in Cook Inlet (the “Working Group”). The Working Group was formed in recognition of the expected decline of aging Cook Inlet natural gas-producing assets and the uncertainty of Cook Inlet natural gas supplies, and its goal was to:

¹⁰ AS 42.05.291(a).

[w]ork together for long-term solutions . . . [which] requires a better understanding of each utility’s constraints and needs based on existing contracts and forecasting our collective demand growth into the next decade.¹¹

The Working Group’s first major milestone was to execute a confidentiality agreement among all the parties in an effort to work together as closely as possible. ENSTAR then proceeded to hire Berkley Research Group (“BRG”) to assist in formulating action plans, methods of determining alternative solutions, and evaluating project costs and feasibility of responsive proposals. Since 2023, the Company has entered into more than 30 non-disclosure agreements to ensure that it considered every qualified concept and entity willing to provide a solution for unmet gas demand in the Cook Inlet.

Following comprehensive research, outreach, analyses, and a resulting market check of the various gas supply solutions for Railbelt utilities, on December 17, 2024, ENSTAR entered into an exclusivity agreement with Glenfarne to develop the Project, which consists of an LNG import terminal that would be co-located with the terminus of the Alaska LNG North Slope Pipeline. The co-location with the pipeline was a key draw of the Project because it would (i) enable ENSTAR to spread project costs over a longer period of time, thus allowing prices to be stabilized for its customers, while (ii) positioning ENSTAR to return to a domestic gas supply once the pipeline became operational. As part of the LNG import terminal, the parties are contemplating that Glenfarne will receive a terminal fee while the LNG terminal functions solely in an import capacity, and a pipeline

¹¹ Docket U-22-090, *ENSTAR Natural Gas Company, LLC’s Petition for Approval to Create a Regulatory Asset for the Accumulation and Deferral of Costs Associated with Studying and Securing Long-Term Gas Supplies for the Alaska Railbelt*, dated Nov. 10, 2022, at Exhibit A.

tariff rate once the pipeline comes online and the LNG terminal is repurposed to support natural gas exports. The Project will supply the Alaska Railbelt with natural gas for heating and power generation and help mitigate the impending supply gap from Cook Inlet gas production.

The exclusivity agreement commits ENSTAR to work exclusively with Glenfarne to facilitate the development of the Project and work toward a Final Investment Decision by the end of 2026. Through this step, the parties agreed to work together to advance the Project, develop a binding Cost Reimbursement Agreement (“CRA”), and execute other applicable definitive agreements. Since that time ENSTAR and Glenfarne have continued to work towards various agreements that will govern the relationship between the parties. Attached as Confidential Attachment A is a copy of the CRA. Attached as Confidential Attachment B is a summary of an additional agreement currently being negotiated between the parties.

Because ENSTAR and Glenfarne have not fully negotiated all of the necessary agreements, the Company does not have final estimates of the projected costs it would seek to recover from customers through rates. ENSTAR received preliminary cost information that Glenfarne provided confidentially during initial discussions when responding to ENSTAR’s market check. As previously mentioned, ENSTAR is currently in negotiations with Glenfarne and expects the costs to be further refined downward. ENSTAR’s selection process and analysis of its decision-making is described in further detail in Section III below.

II. We also require Chugach and ENSTAR to file briefs in this docket addressing our jurisdiction to require utilities to coordinate their proposed use of any

proposed LNG import facility to maximize efficiency and minimize costs to consumers, or [whether such coordination] is otherwise in the public interest.

While the Commission unquestionably has broad authority to regulate public utilities subject to its jurisdiction, whether the Commission has the power to require coordination between ENSTAR and Chugach on the use of any proposed LNG import facility is unclear. AS 42.05.141(a) broadly provides that:

The Regulatory Commission of Alaska may do all things necessary and proper to carry out the purposes and exercise the powers expressly or reasonably implied in this chapter, including . . .

(3) make or require just, fair, and reasonable rates, classifications, regulations, practices, services, and facilities for a public utility.

In describing the Commission's authority, the Alaska Supreme Court has explained as follows:

The commission has implied powers. An organization like the commission "is an administrative agency that has whatever powers are expressly granted to it by the legislature or conferred upon it by implication as necessarily incident to the exercise of powers expressly granted."¹²

Under these broad powers, the Commission has the authority to evaluate whether a proposed gas supply contract is "in the public interest" and whether the utility should recover the costs through rates.¹³ The standard for approval of a gas supply contract is set forth in AS 42.05.141(d) and reads as follows:

When considering whether the approval of a rate or a gas supply contract proposed by a utility to provide a reliable supply of gas for a reasonable price is in the public interest, the commission shall:

¹² *Chugach Elec. Ass'n, Inc. v. RCA*, 49 P.3d 246, 251 (Ak. 2002).

¹³ See AS 42.05.141(d) (addressing Commission's evaluation of "whether the approval of a rate or gas supply contract proposed by a utility to provide a reasonable supply of gas for a reasonable price is in the public interest").

(1) recognize the public benefits of allowing a utility to negotiate different pricing mechanisms with different gas suppliers and to maintain a diversified portfolio of gas supply contracts to protect customers from the risks of inadequate supply or excessive cost that may arise from a single pricing mechanism; and

(2) consider whether a utility could meet its responsibility to the public in a timely manner and without undue risk to the public if the commission fails to approve a rate or a gas supply contract proposed by the utility.

Likewise, the Commission exercises its authority to review the prudence of a utility's capital investments and determine whether the utility may recover the costs through rates. The Commission generally makes this determination after the utility has constructed a facility placed it into service or executed a new gas supply agreement, and can undertake a detailed analysis of the utility's decision if a dispute arises regarding including the costs in rates. Outside of this typical process, the Commission has held that it has the authority to grant a utility's request for an advance determination of prudence and find that an investment is prudent before the utility begins to construct facilities or otherwise incur costs.¹⁴ But granting an advance determination of prudence is different from requiring two utilities to coordinate on a specific investment or resource decision. In short, the Commission's typical role is to allow separate utilities to undertake projects independently and to review their decisions after the utilities makes such decisions. ENSTAR is not aware of any statute or case that squarely addresses whether the Commission has the power to require utilities to coordinate on a particular decision sort of a statutory mandate.

¹⁴ See, e.g., Order U-18-024(17), *Order Denying Petition, in Part, and Closing Docket*, dated Feb. 28, 2019, at 9.

Moreover, requiring coordination between utilities could also run afoul of the Federal Energy Regulatory Commission’s (“FERC”) exclusive jurisdiction to regulate LNG facilities. As the Commission has acknowledged, under the Natural Gas Act (“NGA”), FERC has exclusive jurisdiction over the “siting, construction, expansion, or operation” of an LNG import facility used in interstate or foreign commerce.¹⁵ The Commission also has recognized that an Alaska statute, AS 42.05.711(v), prevents the Commission from assuming jurisdiction over “[a] liquefied natural gas import facility under the jurisdiction of [FERC].”¹⁶ Additionally, the Commission has previously held that FERC’s exclusive jurisdiction deprives the Commission of its power under AS 42.05.221(d) to determine whether a duplication of LNG import facilities would be in the public interest.¹⁷ Requiring ENSTAR and Chugach to coordinate on a particular LNG import decision could encroach on FERC’s exclusive jurisdiction. For example, if the Commission directs ENSTAR and Chugach to coordinate and decide to purchase gas supply from one LNG import facility instead of from two separate facilities, the Commission could encroach on FERC’s exclusive jurisdiction over the “siting, construction, expansion, or operation” of LNG import facilities and could be indirectly

¹⁵ *E.g.*, Order I-26-001(1) at 2 (citing 15 U.S.C. § 717b(e)(1)). The NGA defines an LNG terminal to include: “[A]ll natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquify, or process natural gas that is imported to the United States from a foreign country, exported to a foreign country from the United States, or transported in interstate commerce by waterborne vessel. . . .” 15 U.S.C. § 717(a)(11).

¹⁶ Order U-25-004(5), *Order Closing Regulatory Asset Authorized by Order U-22-090(2), Approving New Regulatory Asset, Denying TA350-4, Finding Motions for Confidential Discovery Orders and Motion for Expedited Consideration Moot, Requiring Filings, Vacating Remaining Procedural Schedule and Hearing, and Appointing Administrative Law Judge*, dated Apr. 22, 2025, at 31 (quoting AS 42.05.711(v)).

¹⁷ Order I-26-001(1) at 2-3.

determining whether duplication of LNG import facilities is in the public interest, which is contrary to its prior findings.

As a regulated public utility serving half of Alaska’s population, ENSTAR has an obligation to provide service that is “reasonably continuous and without unreasonable disruption.”¹⁸ That fundamental mandate guides the Company’s decisions and actions every day. As with all of its decisions, ENSTAR must ensure that any potential LNG supply arrangement helps the Company fulfill that basic statutory mission and is a complete solution capable of meeting its statutory obligations, including the demands of its existing, and future customers.¹⁹ Regardless of whether the Commission has the authority to require coordination or requires coordination if it does have such authority, any decision must be made such that sufficient gas supply is made available to all customers in the Cook Inlet.

III. As part of the above briefing, ENSTAR and Chugach are required to provide specific questions they believe should be considered and a narrative response to those questions.

ENSTAR provides below specific questions that the Company believes the Commission should consider, as well as a narrative response to those questions.

A. Please summarize ENSTAR’s needs for meeting its gas supply portfolio requirements.

ENSTAR’s core mission is to provide safe and reliable natural gas utility service to its customers, 24 hours a day, 365 days per year. As part of this mission, the vast majority

¹⁸ AS 42.05.291(a).

¹⁹ Pursuant to Section 411 of ENSTAR’s Tariff, subject to other requirements such as gas supply availability, the Company is required to provide gas sales service to transportation customers upon one to six-months’ notice from the customer to ENSTAR. Therefore, ENSTAR must be prepared, especially in the current gas supply environment, to meet the needs of current and future customers in its service territory. The Glenfarne Project can readily accommodate not only ENSTAR’s projected demand but also additional Cook Inlet demand should the situation arise.

of the Company's customers rely on ENSTAR not only to deliver gas to their premises, but also to procure the gas that is delivered. Quite simply, if ENSTAR is unable to procure the needed gas, it cannot meet its mandate as a public utility. In addition, ENSTAR must maintain an adequate flow of gas on its pipelines to sustain a certain gas pressure in its transmission pipelines. An adequate pressure is required to deliver gas to its gas sales customers, and just as important to provide service to its transport customers.

As the Commission knows, ENSTAR and other Alaska utilities currently face significant challenges 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.

Despite the already limited nature of production and storage in the Cook Inlet, ENSTAR's analysis of the current gas supply market indicates that the availability of gas supply continues to deteriorate. ENSTAR's operating environment has become increasingly challenging, as the Company has had to meet rising customer demand with declining gas supply resources. HEA, for example, was unable to secure needed gas for power generation for the Kenai Peninsula, and thus became an ENSTAR gas sales

customer. Additionally, over the last three years, the Company's customer base has grown by 5,000 customers, and extreme cold weather events also have resulted in increased demand variability for natural gas. In short, the Cook Inlet market is not able to meet the requirements of all gas users, and utilities and large industrial gas users are struggling to secure gas supply in the market. The well-documented decline in Alaska's natural gas supply has profound impacts for the Company and creates significant gas supply risk and additional costs for its operations.

In ENSTAR's pending base rate case (Docket U-25-013/U-25-019), the direct testimony of ENSTAR witness Inna B. Johansen provides a detailed discussion of the Company's gas supply needs. A copy of Ms. Johansen's testimony without exhibits is attached as Attachment C.

C. What actions did ENSTAR take to evaluate the market for its gas supply needs?

Ms. Johansen's testimony in the Company's pending rate case (Docket U-25-013/U-25-018), also describes actions the Company has taken to evaluate the market for its gas supply needs. Those efforts, and others, are described in further detail below.

1. BRG Phase I Assessment

In May 2022, ENSTAR, Chugach, IGU, MEA, HEA, and GVEA, along with the Alaska DNR and AEA²⁰ formed the Working Group to assess future gas supply needs and energy security in Cook Inlet. The Working Group, through ENSTAR, engaged BRG to conduct a planning assessment to: (i) develop scalable options to fill the natural gas supply

²⁰ DNR and AEA participated in an advisory capacity to provide information to the utilities, as well as remain aware of the effort. The agencies did not fully participate in the deliberations or scoring of options.

gap anticipated to occur as Cook Inlet production declines, including Alaska-based options; (ii) develop and assess high-level project scope, cost estimates, and time to execute for each of the options; (iii) for options requiring LNG imports, analyze the available sources for the required annual volumes of gas, potential contract structure and price ranges; (iv) assess key risk and mitigations associated with each option; and (v) develop a ranking system, ranked assessment of options, and recommendations, all of which comprised BRG's and the Working Group's "Phase I Assessment."

During the Phase I Assessment, BRG and the Working Group collaboratively identified ten project options and developed a scoring methodology for various project options proposed and considered. BRG then conducted a screening-level engineering and commercial evaluation, including cost, permitting, and schedule constraints, to assign scores to each of the ten different project options. At the end of the Phase I Assessment, based on the scoring results, the top three options were: (i) In-State Pipeline – to construct a 24-inch long-distance pipeline across Alaska (if government-subsidized); (ii) Kenai LNG – retrofitting the former Nikiski LNG export facility owned by Marathon to enable LNG imports; and (iii) floating storage and regassification unit ("FSRU") – importing LNG using an FSRU. On June 28, 2023, ENSTAR presented the results of the Phase I Assessment to the Commission during the public meeting. A copy of BRG's Phase I Assessment document is attached as Attachment D. A copy of the presentation to the Commission related to the Phase I Assessment is attached as Attachment E.

2. BRG Phase II Assessment

In the BRG “Phase II Assessment,” BRG continued to refine the project plans for the top-scoring options, conduct commercial diligence, and establish project management strategy. The main scopes of work were: (i) to refine each of the shortlisted options, including site evaluation, design basis, risk analysis, cost model, capital and operating expenditure estimates and integrated schedule; (ii) to conduct LNG sourcing, including market outreach, securing confidentiality agreements and surveying potential LNG suppliers; (iii) to provide a report outlining marine shipping consideration specific to Cook Inlet, and to help formulate a regulatory and commercial strategy for LNG shipping; (iv) to update the supply model for the short-listed options and provide an updated estimate of the cost of delivered gas in \$/Mcf; (v) to seek feedback from the utilities and recommend commercial structure for LNG acquisition and a financing structure for the project; and (vi) to evaluate sourcing and procurement strategies and develop a roadmap for further project development and execution.

Four distinct project options were shortlisted and reviewed in Phase II: (i) modifying Marathon’s jetty and installing onshore storage and regasification at its Kenai LNG facility; (ii) using Marathon’s jetty with an FSRU; (iii) using an FSRU at the Alaska LNG Project’s export dock; and (iv) developing a greenfield FSRU terminal at a new site.

Another option identified as the top-scoring alternative in Phase I, the In-State Pipeline from the North Slope, underwent a permitting review, but not a full conceptual engineering effort. This is because more detailed engineering and permitting work had already been completed on a very similar project that served as the basis for the In-State Pipeline (an Alaska Stand Alone Pipeline owned by Alaska Gasline Development

Corporation (“AGDC”). The threshold barrier to developing a large-diameter pipeline from the North Slope of Alaska by members of the Working Group was the relatively low level of in-state gas demand that made the economics of that project challenging, and prevented the Working Group from being able to move the option forward in a meaningful way without government subsidies.

As part of the Phase II Assessment, BRG and its contractors developed a detailed schedule of activities for the design and development of all four shortlisted options, comprised of up to 170 individual activities per schedule. BRG used a probability analysis for the likely duration of all schedule activities. The key threshold uncertainty in the schedule was the duration of the FERC-led LNG import terminal permitting process, and the nature and extent of the connected National Environmental Policy Act (“NEPA”) review. The integrated schedules were also reviewed by ENSTAR’s legal representatives.

The results of this in-depth analysis showed that none of the four shortlisted options could meet the target of delivering first gas or LNG by late 2027 due to likely permitting and construction schedule constraints. The estimated in-service date for the four large-scale options fell between late 2029 and 2033, with the greenfield option having the longest schedule duration.

These schedule findings prompted a second look at smaller-scale LNG import options that could provide for a more expedited schedule (*i.e.*, earlier first-gas date) and potentially lower “stranded investment” in case of the development of a major gas pipeline project, which would make lower-cost gas available in the long term. The two distinct options that were identified by ENSTAR and BRG were LNG shipments in ISO containers

and LNG shipments using smaller cryogenic vessels. Variations of these options have been examined in earlier stages of feasibility studies, including by ENSTAR in 2020, and were dismissed as either high cost and/or not easily scalable for larger imports. In addition, both options have more limited supply sources than those available using standard-size LNG carriers. However, due to the schedule priority, BRG returned to these options. BRG used the findings of Phases I and II of this project for a refreshed scoping exercise.

A copy of the Phase II Assessment is attached as Attachment F.

3. ENSTAR's Request for Information for Charter of LNG Storage Vessel with Regasification Ability

In October 2024, ENSTAR issued a request for information (“Market Check”) for the purpose of determining market capability and interest in a project in which ENSTAR would charter an LNG FSRU. The Market Check, which was sent to potential service providers that were experienced and had the best potential for being capable of providing service, described in detail the parameters and requirements for such a project, including the FSRU vessel characteristics (such as regasification capacity, gas quality, and estimated annual gas demand), vessel location, vessel mobilization and service period, and cost estimates, among other items. A copy of the Market Check is attached as Confidential Attachment F.

D. How were various gas supply projects that were the subject of the Market Check evaluated?

During the Market Check process, ENSTAR systematically evaluated the viability of proposed projects based on technical design, timeline, and economic feasibility. The Company received four total responses to the Market Check, including one that was non-

conforming due to its land-based project design (the Glenfarne Project). It became evident, however, that Glenfarne's non-conforming proposal offered numerous advantages supporting the overall goal of identifying a bridge solution for natural gas volumes during the anticipated shortfall window. As a result, the evaluation of the results consisted of two parts: (1) an evaluation of conforming project proposals; and (2) a comparison of the highest-scoring conforming proposal and the non-conforming proposal.

Following the Market Check, the four responding parties presented their proposals to ENSTAR and discussed their projects in detail during meetings that took place in October 2024. Prior to the reviews, ENSTAR developed a quantitative response evaluation matrix. Based on the FSRU being a central part of the Market Check process, the selection was weighted heavily toward respondents' experience with building, owning, and operating FSRUs. Therefore, only the three conforming proposals were evaluated using this method. The non-conforming project presented by Glenfarne offered an opportunity that was previously explored in the Phase II Assessment. At the end of the Phase II Assessment, this option was not preferred in part due to the absence of a capable project developer and owner. While the Project received lower scores due to its non-conformance with the Market Check, the evaluation team agreed that the strategic advantages of the Glenfarne Project, particularly its ability to be converted to domestic gas supply if and when the pipeline portion of the Alaska LNG project is constructed, warranted its inclusion in the top two selected options for further evaluation.

To evaluate the two leading project proposals (one of which was the Glenfarne Project) in a quantitative manner, ENSTAR used the original Phase I scoring methodology,

which prioritized the key selection criteria of schedule, reliability, and cost of supply as the top three weighted metrics.

E. Why is the Glenfarne Project the best option for ENSTAR?

ENSTAR performed a systematic, comprehensive evaluation of the two leading proposals, and this analysis ultimately confirmed that the Glenfarne Project represents the best option for meeting the needs of the Company and its thousands of customers in Alaska. The first leading proposal was the Glenfarne Project, and for confidentiality purposes, the second leading proposal will be referred to as “Project B.” As explained above, ENSTAR evaluated the relative advantages and disadvantages of each proposal according to several key metrics, including: technical feasibility; economic feasibility; reliability of supply; timeline and schedule risk; overall project risk; flexibility in scaling supply; permitting; project complexity; environmental impact; and investment size. Although each project had both advantages and disadvantages, the Company’s analysis confirmed that, overall, the Glenfarne Project was the superior option.

As also explained above, ENSTAR evaluated the Glenfarne Project and Project B according to a quantitative scoring methodology that prioritized ten key selection criteria, with schedule risk, reliability of supply, and cost as the top three weighted metrics. In the end, the Glenfarne Project scored better in six of the metrics, including three of the four highest-priority metrics. Project B scored better in two metrics (the fifth and eighth priority metrics), and the remaining two metrics were a tie. The Glenfarne Project was, in other words, clearly superior. ENSTAR witness Ms. Johansen also describes this process on pages 43-44 of her direct testimony in the Company’s pending base rate case, which is also

attached as Attachment C. In a supplemental filing, ENSTAR intends to provide additional details regarding the scoring and evaluation of the Glenfarne Project and Project B.

The Glenfarne Project represents the best option for ENSTAR and its customers for a variety of reasons. Based on preliminary information from Glenfarne, ENSTAR will be able to acquire gas supply from the Project at a reasonable cost to the Company and its customers while meeting existing and future demand scenarios. Further, the Glenfarne Project can be available by 2029, allowing it to fill any electric utility supply gaps.²¹ Finally, the Glenfarne Project also represents the best option for ENSTAR and its customers because of the optionality it provides once the Alaska LNG Project begins exporting LNG. Early on in the evaluation process, ENSTAR was concerned about selecting a project, locking into a long-term contract, and having another option present itself later that met all of the Company's requirements at a lower price. ENSTAR has since concluded that there is only one project capable of that feat, the Alaska LNG Project. The Glenfarne Project allows ENSTAR's customers to stop paying LNG terminal fees once the Alaska LNG Project begins exporting LNG and switch over to procuring North Slope gas.

²¹ If ENSTAR is obligated to provide natural gas service to any potential customer (assuming the customer complies with the applicable provisions of ENSTAR's tariff), then the Company must support an LNG import facility capable of meeting the demands of Chugach, MEA, and HEA. A FERC application for a competing LNG import facility supported by Chugach states that the expansion of its facilities would enable that proposed LNG terminal to receive up to 0.4 million metric tons per annum of LNG and achieve a send out capacity of up to 20 Bcf/year. Cook Inlet's utility natural gas consumers typically require 60 Bcf of natural gas annually. Of this demand, ENSTAR requires a supply of approximately 38 Bcf/year to meet its customers' needs. As currently proposed, the Chugach-supported facility is not capable of meeting those utilities' combined demands of 60 Bcf. If modified, that facility would no longer comport with its existing permit and would need to be significantly changed, which would eliminate the only benefit identified by Chugach as its reason for making its selection. ENSTAR's Motion to Intervene and Limited Comments filed in that docket are attached as Attachment H.

This commercial advantage will allow customers to pay a significantly lower rate than what they are paying today for Cook Inlet gas or for the future price of LNG imports.

F. Please describe Glenfarne's qualifications as relied upon by ENSTAR.

Glenfarne is a developer, owner, and operator of energy infrastructure assets including 57 power plants, four LNG development projects, and various LNG and natural gas commodity management and procurement activities. Glenfarne personnel have served in senior positions across approximately 270 MTPA worth of LNG development, construction, and operations including senior positions at Cheniere, Golden Pass LNG, Cameron LNG, Venture Global, ExxonMobil, Naturgy, and various other LNG-relevant companies. Glenfarne is actively finalizing the financing and entry into construction of Glenfarne's Texas LNG export project having recently assembled a debt financing package of \$5.7 billion. The Texas LNG project will be constructed by Kiewit, a leading North American construction firm in a lumpsum turnkey EPC agreement. Glenfarne stands ready and capable to continue the development, financing, construction, and operations activities of the Project and other Alaska LNG Project components.

As Glenfarne explained in its October 27, 2024 transmittal email responding to the Market Check, Glenfarne is the ideal partner for ENSTAR on this Project, as it brings extensive experience in infrastructure development, particularly in LNG. Glenfarne is uniquely positioned to support ENSTAR, not only with its deep expertise and extensive experience in LNG and infrastructure projects, but also with its ability to develop tailored solutions that address ENSTAR's specific challenges and objectives. A copy of Glenfarne's October 27, 2024 transmittal responding to the Market Check and the response

to the Market Check itself are attached as Confidential Attachments I and J, respectively. In its November 11, 2024 responses to a set of questions from ENSTAR, Glenfarne provided even more information about its experience and capabilities. Those responses are attached as Confidential Attachment K. While various aspects of Glenfarne's submissions have been further developed and refined, their solution is still the best fit for the Company.

G. Please describe the Glenfarne Project.

The information responsive to this question is confidential and provided in Confidential Attachment HH, and includes a detailed description of the Project as well as information regarding timeline and scheduling, permitting requirements, and LNG sourcing.

H. What are the potential gas supply costs?

Because the parties are continuing to negotiate and have not executed any final agreements, the potential costs that ENSTAR might incur to obtain gas supply from Glenfarne are still uncertain. But, ENSTAR engaged BRG to support a detailed assessment of the LNG terminal and supply costs proposed by Glenfarne. BRG's analysis leveraged the data, assumptions, and modeling frameworks developed during the Phase I and Phase II Assessments.

First, BRG evaluated two primary LNG price scenarios to develop a long-term cost-of-supply forecast. Those scenarios were as follows:

1. Global Integrated – Gas Basis:

Henry Hub \times 115% plus a \$5.8/MMBtu adder, with 50% of the adder indexed to inflation.

2. Global Integrated – Oil Basis:

A Brent-linked cost structure using a 13% slope.

BRG also examined several alternative pricing perspectives, including a Canada Free on Board (“FOB”) scenario and seasonal Japan Korea Marker (“JKM”) pricing. However, the reference case used across all full-scale options is the Global Integrated – Gas Basis scenario. This approach reflects the average of the U.S. Energy Information Administration (EIA) 2023 long-term Henry Hub outlooks combined with Henry Hub forward curves from the second half of 2023.

BRG concluded that the Global Integrated – Gas Basis scenario provides the most representative view of the underlying commodity cost. At the time of the study, this scenario also exhibited a narrower spread between market forward curves and EIA price forecasts when compared with the oil-indexed alternative. The selected pricing assumptions were further informed by responses received through ENSTAR’s 2023–2024 LNG Supplier Request for Information (“RFI”) process. Additional detail on BRG’s LNG supply cost modeling is provided in the Phase II Assessment.

Following the commodity cost analysis, BRG performed a second study to estimate the delivered cost of gas, which represents the total cost to bring LNG to ENSTAR’s system and ultimately to consumers. This analysis includes:

- LNG commodity cost (based on the selected Global Integrated – Gas Basis scenario);
- marine transportation and associated shipping logistics;
- terminal infrastructure, including unloading, storage, and regasification facilities;

- pipeline interconnection and system integration requirements;
- operating costs, fuel use, and maintenance; and
- capital recovery for required infrastructure investments.

These components were integrated into a comprehensive cost model that reflects both upfront capital needs and long-term operating and commodity expenditures. The result is a fully burdened, lifecycle-based estimate of the cost of gas delivered into ENSTAR's system under the LNG import scenario.

As part of the comprehensive review of Glenfarne's supply proposal, ENSTAR evaluated the LNG terminal service fees submitted by Glenfarne in response to the Market Check (Confidential Attachment J). These proposed terminal service fees were benchmarked against BRG's cost model to determine their alignment with expected cost structures and to assess overall reasonableness. The results of this evaluation are documented in Confidential Attachment N.

In addition to terminal service pricing, Glenfarne provided a preliminary contract price for natural gas delivered via pipeline from the North Slope to ENSTAR's transmission system in Southcentral Alaska. The proposed pricing terms are outlined in the Letter of Intent executed by both parties on January 21, 2026, provided as Confidential Attachment Q.

To estimate the impact of Glenfarne's proposed gas supply solutions on ENSTAR's customers, ENSTAR applied the same process and methodology used in its annual Gas Cost Adjustment (GCA) model for calculating the Weighted Average Cost of Gas

(WACOG), which is filed with the Commission each year. For this analysis, ENSTAR incorporated the following new supply elements into the WACOG model:

- LNG supply cost estimates developed by BRG in the Phase II Assessment;
- Glenfarne's proposed LNG terminal service fees; and
- Glenfarne's proposed North Slope pipeline-delivered gas pricing.

Integrating these components allowed ENSTAR to quantify how Glenfarne's supply option would flow through to customer rates under existing recovery mechanisms.

The detailed results of this evaluation are provided in Confidential Attachment O.

IV. In addition, ENSTAR and Chugach should provide any documents in their possession that would be responsive to these questions, as well as additional documents they believe the Commission should attempt to obtain from other sources that would be relevant to this inquiry.

The documents responsive to these questions are referenced in the section above and attached to this filing. In addition to the documents referenced above, ENSTAR is also submitting various documents that support the various activities described herein. These are listed on Appendix A to this brief. Additionally, ENSTAR is filing various confidential documents with this brief.

CONCLUSION

ENSTAR appreciates this opportunity to provide information to the Commission on a critical issue for ENSTAR and its thousands of customers across Alaska. ENSTAR has entered into an exclusivity agreement with Glenfarne for the potential development of a Project on the Kenai Peninsula, and the Company believes this opportunity represents the best LNG supply option for the Company and its customers. The Company hopes this informational docket will help confirm the Glenfarne Project as the appropriate path forward for the Company and its customers.

As ENSTAR explained above, the Company has used its best efforts to respond to the Commission's questions and provide relevant documents in the time allowed, but emphasizes that potential LNG-related arrangements are still in flux and under negotiation, and much of the information is confidential, is commercially sensitive, and must not be disclosed publicly. Given the deadline for filing this response and the commercially sensitive nature of the information requested, ENSTAR is continuing to work to identify responsive documents and to determine compliance with third-party agreements before producing documents. Therefore, the Company will need to supplement this filing within the coming weeks. Additionally, ENSTAR welcomes any discussion or further inquiry into the process it undertook or its decision-making after the Commission has had a chance to digest the various materials submitted in this docket.

Dated this 6th day of March, 2026, at Anchorage, Alaska.

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APPENDIX A

Confidential Attachment A	Cost Reimbursement Agreement
Confidential Attachment B	Summaries of Current Drafts of Glenfarne Affiliate-ENSTAR Natural Gas Affiliate Agreements for Natural Gas Supply
Attachment C	Direct Testimony of Inna B. Johansen in Docket U-25-019
Attachment D	BRG Phase I Assessment
Attachment E	Presentation to Commission on BRG Phase I Assessment
Attachment F	BRG Phase II Assessment
Confidential Attachment G	ENSTAR Request for Information (Market Check)
Attachment H	Motion to Intervene and Limited Comments of ENSTAR Natural Gas Company in FERC Docket No. CP26-61-00
Confidential Attachment I	Glenfarne's October 27, 2024 transmittal email regarding response to ENSTAR RFI
Confidential Attachment J	Glenfarne's Response to ENSTAR RFI
Confidential Attachment K	Glenfarne's November 11, 2024 responses to ENSTAR questions
Confidential Attachment L	Map of Proposed Project Site
Confidential Attachment M	Glenfarne Cost of Supply Analysis
Confidential Attachment N	ENSTAR GCA Analysis – March 2026
Confidential Attachment O	Project Timeline
Confidential Attachment P	Letter of Intent
Attachment Q	2024 10 02 CA Standard – ENSTAR LNG RFI
Attachment R	2024-12-17 CIG Letter Agreement Signed
Attachment S	2025-01-15 RCA ENSTAR 2025 Gas Supply Update
Attachment T	2025-06-12 Amendment Letter Agreement.pdf EXECUTED
Attachment U	AK LNG – Enstar Jan 27 Legislative Slides

Attachment V	CIGSP Phase I Report BRG 28June2023 Appendices
Confidential Attachment W	Cook Inlet Gateway LNG Summit_20241217_vF
Confidential Attachment X	BRG Phase II Assessment Apr 2024 FINAL Confidential
Confidential Attachment Y	Glenfarne Import Cook Inlet Demand Scenario
Confidential Attachment Z	Question Response_20241127_vS
Confidential Attachment AA	ENSTAR Confidential Attachments Sections 3 and 5
Confidential Attachment BB	Cook Inlet Supply and Demand Data Apr 2024 – All Utilities
Confidential Attachment CC	BRG Updated Annual Supply and Demand 2-9-2003
Confidential Attachment DD	AK Utility Supply and Demand Data September 2024
Confidential Attachment EE	Demand backup BRG Updated Annual Supply and Demand Added Furie 2-13-2023
Confidential Attachment FF	Cook Inlet Gateway MEA_(20250113)
Confidential Attachment GG	Glenfarne Project Description

1 project, are dedicated and required for this project. So, I
2 think there's -- you know, the hope is and I think the
3 potential of this project is there could be some efficiencies
4 over the long-term, but we're too early in the process to
5 determine that.

6 When I think about, you know, the allocation of costs
7 between, for example, gas supply customers and transmission
8 customers, transportation customers, in our rate cases it's
9 very easy to differentiate and to, you know, show the buckets.
10 Are we going to need that? I don't know that we are, but that
11 will be, you know, for a future filing.

12 CHAIR ESPINDOLA: Thank you. Commissioner Pickett?

13 COMMISSIONER PICKETT: And you don't have to thank me for
14 my questions. This is very, very challenging.....

15 MR. SIMS: Yeah.

16 COMMISSIONER PICKETT:and I think we're out of time
17 frankly. I don't see anything coming in to play before 2030,
18 if we're lucky, and you can't really do much until you have a
19 final investment decision meaning you've got some party that is
20 qualified and ready to sign contracts and I don't see that even
21 under the best of circumstances happening before 2027 with a
22 rural project and you're not going to be able to go to the FERC
23 to apply for an import license.

24 And the only existing import license at the FERC for
25 Alaska is the Marathon facility, which they got in 2020 and on

1 the FERC side, I just went there a couple days ago, it's still
2 listed as being yet to be constructed meaning, you know,
3 they've got the facility obviously, but there's a lot of stuff
4 that still has to happen. So, even if one of the other
5 utilities is trying to negotiate something with Marathon, I
6 would imagine Marathon's made priorities at Tesoro refinery and
7 anything else is totally secondary. If they can get something
8 to fit, they'll probably do it, that's kind of how Marathon
9 does business.

10 So, a lot of unfortunate events legally and regulatory
11 wise have taken place in the LNG arena. Politically last year,
12 there was a big wet blanket put on the whole LNG export and
13 that sort of got pulled back a little bit, but one very
14 critical case in Brownsville, Texas was settled in August of
15 this past summer and it did involve Glenfarne on a smaller LNG
16 export, Texas LNG export and the Rio Grande export across the
17 river much bigger. And the difference between this case, I
18 mean, that had bounced back and forth. Texas LNG first applied
19 for in 2014, Glenfarne got involved, I think, about 2020. It's
20 had a -- the court has remanded it back to the FERC a couple of
21 times.

22 This last time, what they did, it wasn't just a remand, it
23 said your approvals are invalid, we understand final investment
24 and it really affected Rio Grande because they're actually
25 under construction. It said it's all invalid, we're going to

1 just look at this as these approvals never took place and that
2 caused real concern at the FERC because this is the first time
3 that has ever happened.

4 And they made a filing, I believe, back in December
5 sometime advising or requesting that the DC district please,
6 please, please reconsider this ticket to the full panel because
7 this has massive implications and if they don't, it's probably
8 going to -- it will go to the Supreme Court. And how long that
9 takes and what kind of uncertainty that puts on the whole
10 picture is -- it's a mess. I think the DC district screwed up.

11 But FERC kind of screwed up too because they ignored some
12 very strong signals the court was sending them time and time
13 again and that is where it is, and you know, you're negotiating
14 with Glenfarne, they're obviously well aware of it, so that's
15 -- it's not good. But I would also say don't take the way that
16 New Fortress Energy in Puerto Rico took a couple years ago, on
17 an island, short little piece of pipe. They just decided their
18 LNG import facility really wasn't under FERC jurisdiction, so
19 they're just going to go ahead and build it. Well, that didn't
20 work out real well either because the DC district then said no,
21 you're going back to the FERC and you're going to jump through
22 all the hurdles -- and it may -- all these hoops may cost you a
23 lot of money, but that's just the way it is.

24 And so, timing is critical, critical, critical. You know
25 that, but you know, we've -- in your 2020 gas supply filing

1 with us, you clearly identified this and all the utilities then
2 were looking at we're, in all likelihood, going to have to
3 import LNG, but politically in this state, that's still not a
4 very popular thing. You know, I just listened to -- online
5 this morning to the RDC breakfast from last week and it's still
6 like there's some of the legislators, we're going to hold our
7 nose and if the utilities actually think they have to import, I
8 guess we're going to do it for a couple years. You know, if
9 you're investing hundreds of millions of dollars or a billion,
10 it's not going to be a couple years that that's going to be in
11 place.

12 And I was disturbed too and Commissioner Springsteen
13 referred to that in HB50, that language and I'm just going to
14 read it. "Section 49. AS 42.05.711 is amended by adding a new
15 subsection read: (w) A liquefied gas import facility under the
16 jurisdiction of the Federal Energy Regulatory Commission is
17 exempt from this chapter." i.e. 42.05. When you have that sort
18 of specific language, and I think that was a mistake to word it
19 like that. I think what they're trying to do is protect
20 Marathon from some effort to take something. I don't know, I
21 can't speak to that exactly, but when I look at that, when you
22 get to the pre-feed, feed construction engineering stuff and
23 you try to capture it through even a regulatory asset under the
24 jurisdiction of 42.05, and then you
25 get some intervenor that comes in and says no, this is crazy,

1 this is clearly illegal. And that's what's happening. I mean,
2 that's what happened at Brownsville.

3 MR. SIMS: Yeah.

4 COMMISSIONER PICKETT: You had city governments, you had
5 the Sierra Club, you had Earth Justice and a lot of anti-
6 methane jihadists that took advantage of the unclear language
7 -- and they just went for it.

8 And so, I'm not advising that maybe somebody in Juneau
9 needs to look at this because sometimes when they re-look at
10 things, it can get worse, but I think you may be dealing with
11 entirely different Commissioners by the time some of this
12 regulatory asset really starts to pick up. They may look at it
13 and go, you know, what is this, how can we even do this?

14 So, I'm just trying to make your life easier, John.

15 MR. SIMS: Thank you, Commissioner. I'm going to thank
16 you regardless and I -- you know, there's a couple points I
17 want to make, you know, addressing some of the statements
18 there. You know, you made the statement that we're out of
19 time. We are absolutely up against the wall from a time
20 perspective and it was very challenging over the course of this
21 last 24 months to not just say we're going to make a snap
22 decision and go with that.

23 COMMISSIONER PICKETT: I know.

24 MR. SIMS: And you know, we always came back to the
25 position and the perspective that this is a generational type

1 decision. There are significant impacts to peoples' lives that
2 will be the result of this decision that we make. So, we had
3 to make sure that what we were doing was prudent, that it was
4 measured, that it made sense from an operational perspective
5 and always tried to think about minimizing our regret cost.
6 There's going to be regret that comes out of this, there is no
7 doubt about it and so, trying to minimize that as much as
8 possible.

9 And so, you know, even though we were up against a massive
10 time crunch, we always had to have that perspective in mind
11 that the decision we were going to be making was exactly that.
12 It's not a one or two-year timeframe. We're not going to be
13 using these facilities for just a short period of time. So,
14 that was always at the front of our mind and the place that
15 we're at today is with a world class project developer who has
16 some great experience that we believe, after 24 months of
17 review, analysis, engineering, looking at our own systems,
18 understanding the dynamics of the state and the potential of
19 the state.....

20 COMMISSIONER PICKETT: Uh-huh.

21 MR. SIMS:we feel like we have a project that just
22 absolutely knocks it out of the park. And so, even though it's
23 a little later than we would have all hoped, we are very, very
24 optimistic about this and the potential that it brings to the
25 state to minimize regret cost, meet our customers' needs and

1 ultimately be a really, really great solution for the State of
2 Alaska.

3 COMMISSIONER PICKETT: Now you just need to get the
4 communication sales pitch arm of the operation in high gear
5 because I don't think that is accepted widely. You know,
6 Enstar, to its credit, tried to get ahead of this thing early
7 on, you did the survey, we're at 45 percent of the people
8 surveyed thought the State of Alaska was going to fix it. I
9 laughed. When I saw that, I just laughed. I'm not sure what
10 state they thought they were in, but it's definitely not going
11 to happen here.

12 MR. SIMS: Yeah.

13 COMMISSIONER PICKETT: And what is going to have to
14 happen, I'm firmly convinced tariff revisions are going to need
15 to directly address ongoing curtailments because of lack of
16 fuel supply. And so far, we brought all the utilities in last
17 year, we're continuing going back through the cycle, nothing
18 has changed. Nothing has changed.

19 And as I said earlier, I did appreciate the fact RAPA made
20 the petition, I just wasn't convinced it's exactly the right
21 time to do it, but I appreciated their listening, their paying
22 attention and I'm sure they'll continue to pay attention.

23 And so, I honestly wish you the best. I'm an Enstar
24 customer, I'm an MEA customer and I love methane and I love
25 electricity when you flip a switch. And the consequences of

1 that not happening are severe, not just for the Railbelt, but
2 for all of Alaska and I hope everybody can get a handle on it.
3 This is not easy. I keep hearing 19 TCF of gas in Cook -- yes,
4 who's going to bring in a half-a-billion-dollar jack-up rig and
5 when's that going to happen?

6 MR. SIMS: Yeah.

7 COMMISSIONER PICKETT: You know? You don't hear them
8 talking about that and I appreciate the royalty relief
9 discussions, and yes, that's -- have some incremental effect
10 and I appreciate more renewables and all that, but the core
11 issue is the lack of substantial quantities of natural gas that
12 we're seeing projected. So.....

13 MR. SIMS: If I may, just one last comment, you know, to
14 address some of the comments you made about, you know, the
15 survey and whose responsibility of the general public views
16 this as. A majority of them viewed it as the state's
17 responsibility and that is something that we have never
18 believed, that this is our responsibility, which is why, you
19 know, we've been putting a ton of time and effort into this and
20 trying to be as thoughtful as possible.

21 And to take that to another level, we wanted to ensure
22 that the project that we are moving forward with in no way,
23 shape or form needed any sort of legislative ask, dollars from
24 the State of Alaska, you know, new legislation to be passed.
25 We need to be able to do this project on our own, by ourselves

1 with the utility group and a world class project developer and
2 that's what we have today.

3 COMMISSIONER PICKETT: Now be kind, John, they're just
4 trying to be helpful. With that, I see the Chair glaring at
5 me, so I'm going to end my questions.

6 MR. SIMS: Thank you, Commissioner.

7 CHAIR ESPINDOLA: Thank you, Commissioner Pickett. Due to
8 the lengthy discussion and questions, I'm going to go back to
9 Commissioner DeVries online. Commissioner DeVries, do you have
10 any additional questions or comments?

11 COMMISSIONER DEVRIES: No, I don't, but thank you very
12 much.

13 CHAIR ESPINDOLA: Commissioner Springsteen? Johnston?
14 Nope? John, thank you and your team for the presentation.
15 With no more questions or comments from Commissioners, I will
16 close out agenda item number three.

17 MR. SIMS: Thank you.

18 CHAIR ESPINDOLA: The next item on the agenda, agenda item
19 number four, Other Business. Do any Commissioners have other
20 business to discuss?

21 COMMISSIONER PICKETT: Yes, Mr. Chair.

22 CHAIR ESPINDOLA: Commissioner Pickett, the floor is
23 yours.

24 COMMISSIONER PICKETT: I would like to make a motion to
25 open an informational docket to receive information from the

1 electric and gas distribution utilities related to their
2 curtailment procedures and their tariff provisions covering the
3 curtailment procedures. And this is specifically related to
4 how customer curtailment will be conducted, how the
5 communication plans will happen for the potential curtailments.
6 If this motion is successful, I'm proposing to take all of the
7 things that have been filed with us in the last year as we haul
8 the utilities in and for the follow-up reports that are going
9 on this year and then any actions for future presentations the
10 Commission may require. So, that is my motion.

11 CHAIR ESPINDOLA: Do I hear a second?

12 COMMISSIONER SPRINGSTEEN: Commissioner Springsteen, I'll
13 second.

14 CHAIR ESPINDOLA: Thank you. I will now poll the
15 Commission. Commissioner DeVries?

16 COMMISSIONER DEVRIES: Yes.

17 CHAIR ESPINDOLA: Commissioner Springsteen?

18 COMMISSIONER SPRINGSTEEN: Yes.

19 CHAIR ESPINDOLA: Commissioner Johnston?

20 COMMISSIONER JOHNSTON: Yes.

21 CHAIR ESPINDOLA: Commissioner Pickett?

22 COMMISSIONER PICKETT: Yes.

23 CHAIR ESPINDOLA: And I also vote yes. Let the record
24 reflect a 5-0 vote. Are there any other Commissioners that
25 have additional business to discuss? Hearing nothing, agenda

1 item number four, Other Business, is closed.

2 Agenda item number five. The last item on the agenda is
3 Executive Session as required. Assistant Attorney General,
4 Erin Egan, is there a need for Executive Session?

5 MS. EGAN: There's not a need for Executive Session, but
6 if I could follow up on Commissioner Pickett's question from
7 earlier?

8 CHAIR ESPINDOLA: Sure.

9 MS. EGAN: I don't know that it's relevant now, but I did,
10 while we were here, look up the deadline for responding to that
11 petition and it is 30 days. So, for future reference, just
12 wanted to clarify that for the record.

13 CHAIR ESPINDOLA: Thank you. Hearing no need for
14 Executive Session, this meeting is concluded at 10:33 a.m.

15 (Off record)

16 (This proceeding was concluded at 10:33)

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TRANSCRIBER'S CERTIFICATE

I, Sonya Hewes, Transcriber with Accu-Type Depositions, do hereby certify that the foregoing pages numbered 1 through 61 are a true, accurate, and complete transcript of the proceedings of the RCA Special Public Meeting held at the Regulatory Commission of Alaska on Wednesday, January 15th, 2025, as transcribed by me to the best of my knowledge and ability.

1-15-2025

Sonya Hewes
Transcriber
Accu-type Depositions

SB 180 Reinstate/again clarify RCA jurisdiction of consumer rates from utilities.

The RCA on April 20, 2025 handed down an important order in an ENSTAR rate case. ENSTAR had asked for permission to recover \$4.6 million in costs associated with its LNG import facility development by rolling those costs into its Gas Cost Adjustment (GCA) surcharge on customers' bills, rather than waiting for the facility to go into operation, at which time the capital cost would be added to the rate base.

The RCA said no

In that case:

April 22, 2025

Hearing re: RCA U-25-004

ENSTAR explains that future new costs identified in TA350-4 (the rate case) are for the development phase of the LNG Project. They will include commercial, engineering, and permitting activities. ENSTAR divides the proposed development phase costs into two categories: ENSTAR Costs and Developer Costs. ENSTAR further categorizes those costs as project agreements, engineering, and permitting costs. ENSTAR anticipates spending approximately \$10 million on its project development expenditures. This amount includes \$4.6 million ENSTAR already accumulated in its regulatory asset account.

ENSTAR's project agreements costs will be comprised of legal fees, commercial and technical industry consulting, due diligence necessary to vet agreements, and incremental costs associated with regulatory filings. ENSTAR's anticipated engineering costs are to finalize commercial use agreements, project financial security agreements, land agreements, and/or LNG sales and purchase agreements. ENSTAR states it may also need to provide necessary financial security or guarantees and engineering and project management oversight. ENSTAR's permitting costs include legal and technical expenses to support permitting activities, responses to regulators or customers, legal and consulting fees for final approval, intermediate reporting requirements, and preparing for implementation and integration of LNG into the gas system.

The second development cost category includes necessary external and internal costs incurred by the developer. ENSTAR states the Developer Costs will only be recovered through the GCA (Gas Cost Adjustment) if the LNG Project is suspended, terminated, or cancelled. If the LNG Project is built, those Developer Costs will instead be included as capital costs in the new LNG Project. The owners of the LNG Project will then recover those capital costs through supply purchase or import terminal use agreements once the LNG Project is operational. ENSTAR predicts that (its) Developer Costs will be between \$43 and \$48 million.

ENSTAR differentiates the costs at issue in TA350-4 as related to securing a gas supply and formalizing a commercial relationship with the import facility and LNG suppliers which falls within our authority, unlike the construction or operation of the facility which would be within FERC's exclusive jurisdiction. As an analogy, ENSTAR notes RCA has jurisdiction to regulate ENSTAR as a utility-offtaker of Cook Inlet producers' platforms and pipelines. Likewise, ENSTAR asserts that although the LNG Project may not be regulated by us,

ENSTAR argues that the proposed costs identified in TA350-4 meet adjustment clause criteria listed in 3 AAC 52.502(a). ENSTAR argues that importing LNG to the Cook Inlet is an unprecedented event in Alaska history and the costs to proceed with it represent unusual fuel costs. ENSTAR states that the LNG Project's development costs are subject to change at a rate that would cause financial harm to ENSTAR if recovered exclusively in base rates. ENSTAR asserts that the costs are beyond ENSTAR's control because it must incur these costs to advance the LNG Project. ENSTAR states that these costs will vary year-to-year and will be dictated by the various project agreements and the engineering and permitting activities that it will be required to complete. ENSTAR states that it has no control over these factors.

JLP/RSD (JL Properties and RSD Properties, an intervenor) argue that RCA does not have and should not exercise jurisdiction over LNG import facilities. JLP/RSD assert that ENSTAR is planning to advance funds for the LNG Project that will receive gas transported in interstate commerce and is defined in TA350-4 as "construct[ion] of a natural gas receiving terminal on the Kenai Peninsula, in close proximity to ENSTAR transmission and storage facilities." JLP/RSD cite 15 U.S.C § 717b(e)(1) which states that FERC "shall have the exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal." Therefore, JLP/RSD argue that the LNG Project, as defined by ENSTAR, and all agreements related to the interstate transportation of natural gas, are subject to exclusive FERC jurisdiction.

JLP/RSD argue that the Legislature's intent to restrict Commission jurisdiction by adopting AS 42.05.711(v) was shown when it expressly decided to remove language stating "[f]or rate-making purposes, the commission shall consider the investment of a public utility in a liquified natural gas import or export facility" from HB 50. JLP/RSD assert this language appeared in the Senate Finance Committee draft of HB 50 but was subsequently amended to state, "For rate-making purposes, the commission shall not consider the investment of a public utility in a liquified natural gas import or export facility."

Chugach Electric Association argues that FERC's jurisdiction over the siting, construction, operation, or expansion of an LNG import or export facility is exclusive under 15 U.S.C. § 717b(e).⁹⁵ **However, Chugach points out FERC's jurisdiction does not extend to price regulation of imported LNG, nor to an LDC's decision to procure gas supplies or capacity in a FERC jurisdictional project like an LNG import facility. The review of those determinations falls to state regulatory commissions who hold jurisdictional authority to review such terms.**

CONCLUSION

We (RCA) do not see a viable path to acquiring jurisdiction over facility. Were we to do so, we would violate AS 42.05.711(v). This subsection provides that "A liquified natural gas import facility under the jurisdiction of the Federal Energy Regulatory Commission is exempt from this chapter." (My note: This applies to the physical facility, not utility contracts.)

We have jurisdiction to consider gas supply and terminal use agreements arising from ENSTAR's use of an LNG import facility's services, and we are not barred by AS 42.05.711(v) from doing so.

ENSTAR does attempt to show these regulatory asset costs have an adequate linkage with variable fuel costs permitted for recovery through a GCA or a COPA (Cost of Power Adjustment). While first stating the costs included in the \$4.6 million regulatory asset pertain to "studying and securing long term gas supply," it subsequently adds they are "related to the importation of LNG to the Cook Inlet" and that this "unprecedented event" represents "unusual fuel costs" which should be granted GCA treatment. **However, as RAPA (Department of Law Advocacy Office) points out, these costs are operating expenses; they do not relate to changes in fuel supply as defined in 3 AAC 52.519(a)(1). We agree. The costs included in the \$4.6 million regulatory asset are operating expenses. They are not commodity costs contemplated by 3 AAC 52.519(a)(1) for inclusion in GCA recovery.**

For the above reasons, we deny ENSTAR's request. ENSTAR may seek to address this \$4.6 million regulatory asset and an appropriate amortization period in its next rate case.

For many of the same reasons we rejected GCA treatment for ENSTAR's \$4.6 million regulatory asset, we deny ENSTAR's request for GCA treatment of its development costs, and the lump sum payment due to the developer under Scenario 2 if the Project is terminated. First, the costs ENSTAR describes as its development costs, and for those of the developer, are non-fuel-related operating expenses. They are not fuel related expenses of the sort identified by 3 AAC 52.519(a)(1). ... It would be unreasonable for us to require ratepayers to fully compensate ENSTAR for this business risk in rates, and then require ratepayers again to fully absorb all LNG development costs without any cost allocation to ENSTAR when its shareholders have already been compensated for this business risk.