Dr. Gwen Holdmann
Alaska Center for Energy & Power
University of Alaska Fairbanks
January 15, 2026

Budget & Audit Committee
cc: Jeff Stepp
34th Alaska Legislature
1500 W Benson Boulevard
Anchorage, AK 99503

Subject: Report on ACEP and ISER Legislative Support Activities Related to ADN#332501

Dear Chair Gray-Jackson and Members of the Legislative Budget & Audit Committee,

Thank you for the opportunity to work with the Alaska State Legislature this year. ACEP and ISER, as research institutes within the University of Alaska system, take pride in providing nonpartisan, data-driven research to inform policy decisions.

Attached is a report summarizing the specific activities we undertook in support of legislative committees and individual lawmakers during the First Session of the 34th Alaska State Legislature and the following interim. In total, we expended $44,320 on nine discrete tasks, including both invited testimony and the production of research briefs. Please note that, where possible, we leveraged complementary funding sources—particularly where existing research efforts aligned with legislative tasks—to allow for deeper analysis.

Sincerely,

Dr. Gwen Holdmann
Chief Scientist

Alaska Center for Energy and Power • University of Alaska Fairbanks • 1764 Tanana Loop – JUB Suite 404
P.O. Box 755910 • Fairbanks, Alaska 99775-5910 • Tel: (907) 474-5402 • Fax: (907) 474-5475

ACEP/ISER Legislative Research Support

Contract: ADN#332501
Start Date: February 26, 2025
End Date: December 31, 2025
Budget: $50,000
Total Expenditures to Date: $44,319

The following activities represent specific tasks and associated work products or deliverables prepared by ACEP and ISER. Where possible, we have linked to presentations submitted to legislative staff and preserved on the BASIS website. Deliverables that are not otherwise available are attached to this report in Appendix B.

Both ACEP and ISER were able to leverage complementary resources from third-party grants and contracts to supplement the funds provided by LB&A. These external resources were utilized in cases where the associated scope of work aligned with legislative requests and ongoing activities. This leverage represents a valuable and ongoing opportunity to harness the broader research capacity of the University of Alaska in support of legislative needs.

Summary of Deliverables

Below is a list of tasks assigned to ACEP/ISER. Original task orders are provided in Appendix A for reference. Research briefs resulting from specific tasks are provided in Appendix B.

TASK 001

Date Requested: February 10, 2025, formal request April 1, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Date Completed: April 2, 2025

A technical review of Senate Bill 91: “An Act Establishing the Clean Energy Project Development License and Leasing Framework”, including technical observations, implementation concerns, industry stakeholder engagement and feedback, and engagement with state agencies to clarify existing land management statutes and permitting processes.

TASK 002

Date Requested: April 1, 2025
Requested By: Representative Ky Holland (House Energy Committee)
Date Completed: April 22, 2025

A research review conducted in support of HB153: "An Act relating to generation of electricity from renewable energy resources; relating to a renewable portfolio standard; relating to power cost equalization; and providing for an effective date." A comparative review of five recent studies assessing technical and economic feasibility of incorporating renewable energy on the Railbelt, with consideration of implications for reliability and consumer rates.

TASK 003

Date Requested: May 5, 2025
Requested By: Shaina Kilcoyne and Hunter Lottsfeldt, Staff to Representative Ky Holland (House Energy Committee) and Staff to Senator Bill Wielechowski
Date Completed: December 5, 2025
See *Railbelt Futures Studies: Initial Comparison of Methods, Assumptions, and Results* in Appendix B

At the request of legislative staff, ACEP has further refined Task 002 by dividing it into two components for clarity and usability. These have been marked as non-urgent, and so have been pushed to after the end of the legislative session:

- Part A – Reference Brief:
  This section will provide a comparative analysis of relevant Railbelt energy studies. It involves removing Sections 1 and 4 from the original draft, reworking Appendix 2, and expanding Appendix 1 (the comparison table). The updated version will include a summary of the strengths and limitations of each study to aid in interpretation and cross-reference.

- Part B – Price and Methodology Addendum:
  This component expands on the content originally included in Section 1 by incorporating additional data on renewable energy costs and natural gas price projections. It will also clarify the methodology used to develop the comparative pricing chart to ensure transparency and replicability.

TASK 004

Date Requested: April 29, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Date Completed: April 30, 2025

ACEP provided analysis and subject matter expertise for the review of committee substitute (CS(I)) for Senate Bill 32, titled: "An Act relating to costs incurred by certain electric utilities for renewable energy and battery energy storage." This included analysis of the implications of the revisions within the CS, developing and delivering a presentation summarizing the technical rationale behind the revisions, and participating in the Senate Resources Committee hearing to provide invited testimony and answer questions.

TASK 005

Date Requested: April 6, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Date Completed: April 9, 2025

ACEP provided invited testimony and responded to questions, as requested by staff member Intimayo Harbison, on behalf of Senator Giessel at the second hearing of Senate Bill

190 titled: “An Act relating to the regulation of liquefied natural gas import facilities by the Regulatory Commission of Alaska.”

TASK 006a (funded primarily using complementary resources)

Date Requested: April 6, 2025
Requested By: Representative Zack Fields (House Energy Committee)
Date Completed: May 16, 2025
See *Residential Rate Trends: Kodiak Electric Association vs. Railbelt Utilities* in Appendix B

ACEP evaluated the relationship between renewable energy and electricity prices in areas that have increased renewable shares and assessed whether large-scale integration of renewables achieves long term cost-savings, and how. The evaluation looked specifically at how electricity rates have changed over time in states or regions that have invested heavily in renewable energy; how different types of renewable energy—such as wind, solar, or hydro—and ownership structures impact the cost of electricity for consumers; and how broader factors, like the size of the electric grid, reliance on fossil fuels, or the ability to share power across regions, influence how renewables affect electricity rates. In particular, we were asked to examine the historical trends in residential electricity rates for Kodiak Electric Association (KEA) compared to the average rates of Railbelt utilities. KEA, notable for generating nearly 100% of its electricity from renewable sources, maintained flat rates for nearly three decades before implementing a rate increase in 2023. The Railbelt region, by contrast, reflects a more typical trend of rising rates over time, largely influenced by fuel price volatility and system-wide cost increases.

TASK 006b (funded primarily using complementary resources)

Date Requested: May 16, 2025
Requested By: Representative Zack Fields (House Energy Committee)
Date Completed: July 9, 2025
See *Insights for Alaska's Railbelt from Kauai Island Utility Cooperative* in Appendix B

Extension of the analysis on Kodiak Electric Association to consider Kauai Island Utility Cooperative as an example of a high-penetration renewables grid and assessment of cost implications (primarily funded through complementary ACEP grant-funded resources).

TASK 007

Date Requested: October 30, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Date completed: December 23, 2025
See *HB 307 Requirements and Railbelt Transmission Organization Update* in Appendix B

ACEP provided an update on progress toward meeting the requirements established under House Bill 307 (HB 307), enacted as Chapter 24, SLA 2024 with the intent to provide the Legislature with a clear summary of implementation progress, highlight areas of regulatory focus and contention, and place current RCA proceedings in the context of the directives and policy objectives set forth in HB 307. It covers actions taken between September 2024 and October 2025, including formation of the RTO, submission and approval of its certificate application, and subsequent filings with the RCA related to the OATT. It also outlines major issues now under consideration in RCA docket U-25-028, which was opened to review the OATT proposal—most notably, the proposed “regional allocator” for cost distribution and the treatment of “grandfathered agreements” that preserve existing wheeling arrangements.

TASK 008

Date Requested: October 30, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Date completed: November 6, 2025
See *Energy Legislation Proposed in 34th Alaska Legislature (2024-2025)* in Appendix B

ACEP prepared a non-partisan summary “Energy Legislation Proposed in the 34th Alaska Legislature (2024–2025),” including a summary table and brief descriptions for each relevant bill to serve as a reference for legislators, staff, and policy analysts seeking a clear overview of current and proposed statutory changes affecting Alaska’s energy systems, utilities, and infrastructure. The summary table lists each bill’s number, short title, primary sponsor, and current committee status, and the narrative summaries describe the purpose, key provisions, and potential implications of each bill.

Budget

The cumulative cost of the project across all tasks was **$44,320**, including **$35,456** in direct expenditures and **$8,864** in indirect costs. Costs were incurred in accordance with the approved budget and are consistent with the scope of work and deliverables outlined in the agreement. These are broken down below as follows.

Personnel Costs: $32,156

Salaries and fringe benefits for subject matter experts and staff involved in tasks and associated work products.

- Dr. Gwen Holdmann, Chief Scientist - $10,699
- Dr. Steve Colt - $14,414
- Dr. Laurent Nassif - $1,092
- Ms. Clare Loftus - $1,189
- Ms. Jennifer Pemberton - $4,762

Other Direct Costs: $3,300 Data analysis support from DOWL Engineering

Indirect Costs: $8,864: Calculated at 25% in accordance with the State of Alaska negotiated rate

Appendix A: Task Orders

ACEP TASK ORDER 001

Title: SB91 Review
Date Requested: February 10, 2025; formal request April 1, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Request Approved: N/A

Overview

This task order documents ACEP's internal technical review of Senate Bill 91, titled: "An Act establishing the clean energy project development license and leasing framework." Although no formal testimony was requested, ACEP prepared written feedback in collaboration with ISER at UAA to assist legislative staff and state agencies in evaluating the implications of the proposed legislation.

Scope of Work

ACEP undertook the following activities as part of this review:

- Reviewed SB91 and prepared a memo outlining technical observations and potential implementation concerns, dated April 2, 2025.
- Met with interested industry stakeholders who expressed support for the bill to better understand the problem they are seeking to address through the proposed legislation.
- Engaged with state agencies to clarify how the bill aligns with existing land management statutes and permitting processes.

Date of review completion: April 2, 2025

Deliverables

Memo to bill sponsor dated April 2, 2025.

ACEP TASK ORDER 002

Title: Research for HB153
Date Requested: April 1, 2025
Requested By: Representative Ky Holland (House Energy Committee)
Request Approved: April 2, 2025

Overview

This request relates to research conducted to support HB153, "An Act relating to generation of electricity from renewable energy resources; relating to a renewable portfolio standard; relating to power cost equalization; and providing for an effective date." There are a number of reports and studies that have been completed in the last 5 years that provide information related to the technical and economic feasibility of incorporating renewable energy on the Railbelt Grid. The purpose is to review these studies, and show possible rate implications from a rate-payer perspective.

Scope of Work

Using the following studies and reports, compare methods, assumptions and results to create a report on the costs and benefits of near-term energy infrastructure investment with the year 2035 as a target.

1. Denholm, Paul, Marty Schwarz, and Lauren Streitmatter. 2024. *Achieving an 80% Renewable Portfolio in Alaska's Railbelt: Cost Analysis.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85879.

2. Energy and Environmental Economics, Inc. 2024. *Alaska Railbelt Wind Integration Study.*

3. P. Cicilio et al., "*Alaska's Railbelt Electric System: Decarbonization Scenarios for 2050,*" Alaska Center for Energy and Power, University of Alaska, Fairbanks, 2023. UAF/ACEP/TP-01-0003.

4. Electric Power Systems, Inc. 2024. Railbelt Wind Integration Study.

5. Chugach Electric Association, *Integrated Resource Plan, 2024*.

These reports already contain load growth projections for the Railbelt, integration feasibility, cost estimates for the proposed projects, and fuel cost assumptions. This project should lean on these findings to expedite the process, updating assumptions with current data and RCA filings when possible.

Show all costs from a rate-payer perspective using RCA filings.

Date of review completion: April 22, 2025

Deliverables

Memo dated April 21, 2025, titled "ACEP Memo on Railbelt Studies Comparison 21Apr2025"

ACEP TASK ORDER 003

Title: Follow up to Task Order 002: Research for HB153
Date Requested: May 5, 2025
Requested By: Shaina Kilcoyne and Hunter Lottsfeldt, Staff to Representative Ky Holland (House Energy Committee) and Staff to Senator Bill Wielechowski
Request Approved: N/A (followup on to Task 2)

Overview

Staff have requested we rework the memo produced as a deliverable for Task Order 002 to divide it into two deliverables:

1. First a “cheat sheet” for these studies, removing section 1 and section 4 and reworking appendix 2. Build on appendix 1 (comparison table). Include information on the strengths and weaknesses of each study.
2. Expand on Section 1 to incorporate other known price information of both renewables, as well as projections for gas. Add clarification on methodology on how the chart was developed.

Scope of Work

Develop a new version of the Memo dated April 21, 2025, titled “ACEP Memo on Railbelt Studies Comparison 21Apr2025”

Deliverables

Two research briefs, planned to be completed April 9, 2025.

ACEP TASK ORDER 004

Title: Review CS(I) for SB32 and Provide Testimony
Date Requested: April 30, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Request Approved: N/A

Overview

This task order responds to a request from Senator Cathy Giessel to support legislative review of the committee substitute (CS(I)) for Senate Bill 32, titled: "An Act relating to costs incurred by certain electric utilities for renewable energy and battery energy storage." ACEP has been asked to provide subject matter expertise to help inform committee deliberations.

Scope of Work

ACEP will provide technical assistance in the form of expert testimony and supporting materials. Specific tasks include:

- Analyze the implications of the revisions in the CS, particularly the change from 15 MW to 5 MW and limitations to three projects in a three-year period, in the context of technical constraints and existing state statute (AS 42.05.785)
- Develop and deliver a presentation summarizing the technical and policy rationale behind the revisions in the CS.
- Attend and participate in the Senate Resources Committee hearing, originally scheduled for May 1, 2025 (subsequently rescheduled to May 5, 2025), to provide testimony and respond to committee questions.

Date of completion: April 5, 2025

Deliverables

PowerPoint Presentation CS for SB32

ACEP TASK ORDER 005

Title: SME Testimony SB190
Date Requested: April 6, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Request Approved: N/A

Overview

This task order responds to a request from the office of Senator Cathy Giessel, communicated by staff member Intimayo Harbison, to provide invited testimony at the second hearing of Senate Bill 190 on May 9, 2025. The bill is titled: “An Act relating to the regulation of liquefied natural gas import facilities by the Regulatory Commission of Alaska.”

Scope of Work

Attend and participate in the Senate Resources Committee hearing on May 9, 2025, to present findings and respond to questions from committee members.
Date of completion: April 9, 2025

Deliverables

PowerPoint Presentation SB 190

ACEP TASK ORDER 006a

Title: Residential Rate Trends: Kodiak Electric Association vs. Railbelt Utilities
Date Requested: April 9, 2025
Requested By: Representative Zack Fields (House Energy Committee)
Request Approved: N/A

Overview

ACEP will evaluate the relationship between renewable energy adoption and electricity prices in regions that have significantly increased their share of renewables. This analysis will explore whether large-scale integration of renewable energy leads to long-term cost savings, and under what conditions. Specifically, we will examine how electricity rates have evolved over time in states and regions with substantial renewable energy investments; how the type of renewable resource—such as wind, solar, or hydro—and ownership structures influence electricity costs for consumers; and how broader system factors, such as grid size, fossil fuel dependence, and the ability to share power across regions, shape the impact of renewables on rates.

Scope of Work

Analyze historical residential electricity rates for Kodiak Electric Association (KEA) in comparison to the average rates of Railbelt utilities. KEA, which generates nearly 100% of its electricity from renewable sources, maintained stable rates for nearly three decades before implementing a rate increase in 2023. This will be contrasted with the Railbelt region, where rates have generally increased over time due to factors such as fuel price volatility and system-wide cost pressures.

Deliverables

Memo detailing research in Task 1.

ACEP TASK ORDER 006b

Title: Residential Rate Trends: Kauai Island Utility Cooperative vs. Hawaii Electric Company (HECO)
Date Requested: May 16, 2025
Requested By: Representative Zack Fields (House Energy Committee)
Request Approved: N/A (funded using complementary resources)

Overview

Repeat analysis completed for Task Order 6.

Scope of Work

Extension of the analysis on Kodiak Electric Association to consider Kauai Island Utility Cooperative as an example of a high-penetration renewables grid and assessment of cost implications.

Deliverables

Research briefing to be completed by July 9, 2025.

ACEP TASK ORDER 007

Title: HB 307 Legislative Update
Date Requested: October 30, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Request Approved: November 3, 20205

Overview

This task order documents ACEP's preparation of a legislative update summarizing progress toward the requirements established under House Bill 307 (Ch. 24, SLA 2024). The bill directed the Alaska Energy Authority and Railbelt utilities to form the Railbelt Transmission Organization (RTO) by January 1, 2025, and to apply to the Regulatory Commission of Alaska (RCA) for certification to manage the Railbelt backbone transmission system. It also required the RTO to develop a nondiscriminatory open-access transmission tariff (OATT) consistent with FERC standards.

Scope of Work

The update was requested to inform legislators of milestones achieved since the RTO's inception, summarize the ongoing RCA review of the OATT under docket U-25-028, and identify key issues of interpretation and implementation related to HB 307. Specific tasks include:

- Review HB 307 statutory requirements and legislative intent.
- Compile a timeline of RTO formation and RCA actions from September 2024 to October 2025.
- Analyze RCA orders and filings related to the OATT, including docket U-25-028 (Order #1 and subsequent proceedings).
- Summarize major issues under review, including the proposed "Regional Allocator" methodology for cost allocation and treatment of "Grandfathered Agreements" that preserve legacy wheeling.
- Provide contextual analysis clarifying how these developments align with HB 307's policy objectives to improve Railbelt efficiency, reduce costs, and remove barriers to competition.

Deliverables

Written report titled *HB 307 Requirements and Railbelt Transmission Organization Update*.

ACEP TASK ORDER 008

Title: Energy Legislation Update
Date Requested: October 30, 2025
Requested By: Senator Cathy Giessel (Senate Resources Committee)
Request Approved: November 3, 2025

Overview

Under this task, ACEP will prepare a non-partisan summary of energy-related legislation introduced during the 34th Alaska Legislature (2024–2025). The resulting document will serve as a reference for legislators, staff, and policy analysts seeking a clear overview of current and proposed statutory changes affecting Alaska's energy systems, utilities, and infrastructure.

Scope of Work

ACEP will:

- Review all House and Senate bills introduced during the 34th Legislature to identify measures related to energy, utilities, taxation, and climate policy.
- Compile and maintain a summary table listing each bill's number, short title, primary sponsor, and current committee status.
- Draft concise narrative summaries describing the purpose, key provisions, and potential implications of each bill.
- Cross-check all information against official legislative sources, including BASIS and committee documents, to ensure accuracy and neutrality.

Deliverables

Written report titled *Energy Legislation Proposed in the 34th Alaska Legislature (2024–2025)*, including a summary table and brief descriptions for each relevant bill.

Appendix B: Research Briefings

1) Railbelt Futures Studies: Initial Comparison of Methods, Assumptions, and Results [Task 003]
2) Residential Rate Trends: Kodiak Electric Association vs. Railbelt Utilities [Task 006a]
3) Insights for Alaska's Railbelt from Kauai Island Utility Cooperative [Task 006b]
4) HB 307 Requirements and Railbelt Transmission Organization Update [Task 007]
5) Energy Legislation Proposed in 34th Alaska Legislature (2024-2025) [Task 008]

Railbelt Futures Studies: Comparison of Methods, Assumptions, and Results

DRAFT FINAL – December 5, 2025

prepared for:
Alaska Legislative Budget and Audit Committee by request of House Energy Committee

prepared by:
Gwen Holdmann (gwen.holdmann@alaska.edu) and Steve Colt (sgcolt@alaska.edu)
Alaska Center for Energy and Power, UAF

Contents

1. Introduction and Summary

This research memorandum compares findings from six recent studies that explore the future of the Railbelt electric system, focusing on renewable energy integration, cost, and system reliability. There are four primary studies. All four:

- were completed in 2024
- used "dispatch modeling" techniques[1] that require a balance between electricity supply and demand on an hourly or sub-hourly basis
- considered substantial additions of renewable resources.

A fifth study (EPS 2024) provided technical inputs to one of the four. A sixth, completed in 2022 and only in draft, provides useful historical context.

[1] Also known as "production cost modeling"

It is critical to keep in mind that **all six studies used wind and solar cost assumptions based on a 30% or 40% investment tax credit.**[2] Those credits are currently scheduled to expire for projects not commenced before July 4, 2026.[3]

All six studies use sound methodologies and well-supported assumptions, and all are technically rigorous, complex, and data-rich. Each study addresses **different questions** about the Railbelt's future: No study is "right" and no study is "wrong."

Broadly, all six studies support two main conclusions:

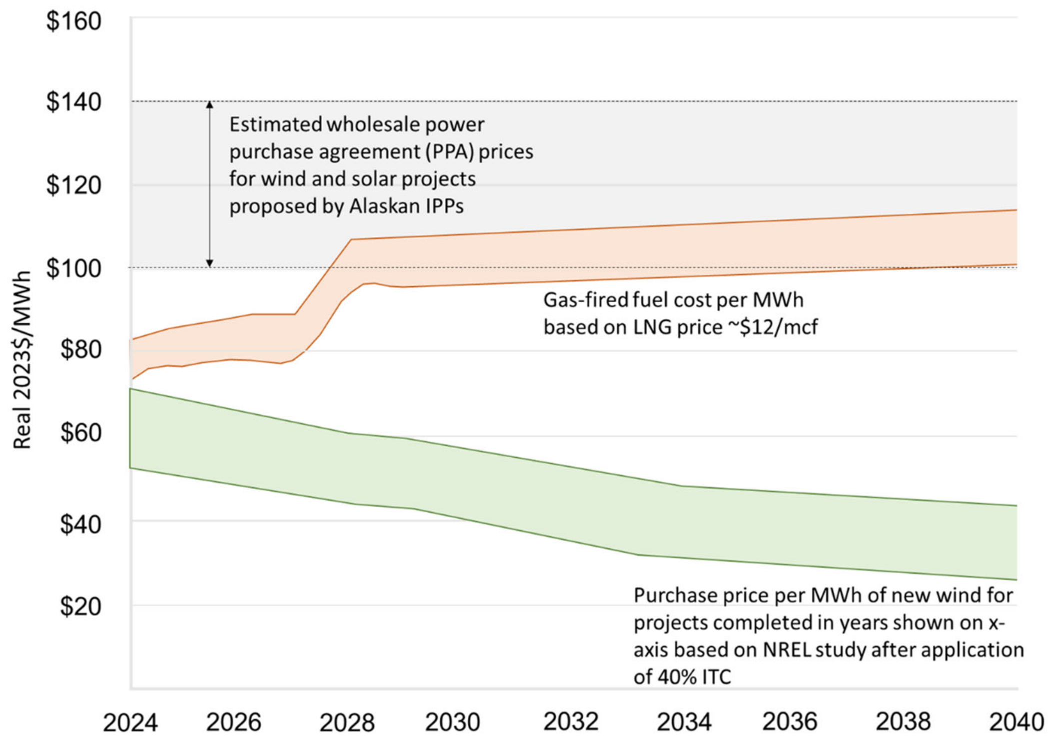
- First, renewable resources—particularly wind—could provide a significant share of Railbelt electricity without compromising reliability or grid stability.
- Second, for these resources to be cost-effective for consumers, they must be priced to accommodate utility integration costs and still remain competitive with the benchmark avoided production cost of LNG-fired generation, estimated at approximately $100 to $120 per MWh (in 2023$)[4].

Figure 1 is broadly consistent with all six studies. It illustrates both the economic challenge and the potential opportunity for renewable electricity generation on the Railbelt. The red band represents the avoidable fuel cost of electricity generated from natural gas, estimated at $100–$120 per MWh by 2030, based on an LNG price of $12 per million Btu (in 2023 dollars).[5] All four dispatch modeling studies assume a benchmark LNG price of $12–$14 per million Btu, with no expectation of significant real price escalation—though future LNG prices remain inherently uncertain.

The green band, drawn from NREL's 2024 cost analysis, reflects an optimistic scenario for the price of wind energy that an independent power producer (IPP) might be able to offer to a Railbelt utility under a power purchase agreement (PPA). This PPA price is derived from cost projections for Lower 48 markets **and assumes the availability of the 40% investment tax credit** that was provided by the Inflation Reduction Act and is now only available for projects with construction commencing by July 4, 2026 or completed before the end of 2027.[6] In contrast, the gray band presents a more conservative view of potential PPA prices, reflecting higher projected costs for wind or solar generation. These higher estimates were developed by the authors of this memo through discussions with Railbelt utility staff and IPPs over the past year, as well as from actual power purchase agreements (PPAs) negotiated on the Railbelt in recent years.

[2] https://nccleantech.ncsu.edu/2024/11/19/the-past-present-and-future-of-federal-tax-credits-for-renewable-energy/
[3] https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape
[4] Unless otherwise noted, all dollar amounts are presented in 2023$.
[5] We assume that one million btu, or MMbtu, has the same energy content as 1 thousand cubic feet of gas (1 MMbtu = 1 mcf).
[6] https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape

Figure 1. Electricity production cost comparison



Data sources: Red and green bands from NREL 2024, Figure 6a and Figure 38. Gray band: ACEP estimates based on discussions with utility staff and IPPs.

As a rough approximation, Figure 1 suggests that renewable energy offered to (or produced by) Railbelt utilities at prices below $80 per MWh can compete economically with LNG. Conversely, if the cost exceeds $110 per MWh, it is unlikely to be competitive.

Figure 1 helps explain why there is ongoing debate about the economic viability of renewables on the Railbelt. What might be termed the "optimistic view" assumes renewable costs fall within the green band—well below the cost of LNG—implying substantial consumer savings. The 2024 Chugach Integrated Resource Plan (IRP) aligns with this perspective, recommending significant wind development over the next 25 years. In contrast, ACEP's wind-solar scenario analysis places renewable generation costs closer to the red band even in year 2050, due to higher projected capital expenses and additional system costs required to maintain reliability.

The challenge of maintaining reliability and system stability feeds into the Figure 1 picture. For example, the E3 Railbelt wind integration study uses NREL fuel costs but adds in operational constraints – chiefly the need to run certain thermal units at all times – that are needed to add 300 MW of wind to the existing system. These constraints increase the total fuel burn and reduce the net avoided cost of LNG generation below the amount of "raw" fuel savings, effectively lowering the red band in Figure 1. Finally, if one believes that renewables prices (or self-build costs) are higher than $100 per MWh, it puts renewables in the grey zone where they are not cost-effective against LNG. Combinations of these viewpoints also make sense; one might see renewables as ultimately cost-effective, but not quite yet.

2. Study Summaries

This memo compares findings from six recent studies that explore the future of the Railbelt electric system, focusing on renewable energy integration, cost, and system reliability. As noted above, the four primary studies use hourly or sub-hourly dispatch modeling or rely heavily on dispatch-modeling results to assess system performance under various resource scenarios. The fifth (EPS 24) provides key technical inputs to the E3 wind integration study. The sixth (Railbelt 2022) offers useful historical context.

The six studies are:

1. NREL 2024 – Denholm, Paul, Marty Schwarz, and Lauren Streitmatter. 2024. Achieving an 80% Renewable Portfolio in Alaska's Railbelt: Cost Analysis. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85879.
2. E3 2024 – Energy and Environmental Economics, Inc. 2024. Alaska Railbelt Wind Integration Study. (slide show version).
3. Chugach IRP 2024 – Chugach Electric Association, Integrated Resource Plan, 2024.
4. ACEP 2024 – P. Cicilio et al., "Alaska's Railbelt Electric System: Decarbonization Scenarios for 2050," Alaska Center for Energy and Power, University of Alaska, Fairbanks, 2023. and wind-solar scenario results.
5. EPS 2024[7] – Electric Power Systems, Inc. 2024. Railbelt Wind Integration Study. (Provides inputs to E3 2024)
6. Railbelt 2022[8] – Railbelt Utilities Compliance Cost Impacts Prefeasibility Analysis, 2022

In addition, we considered two supplemental studies that provide projections of LNG gas supply costs—an important input in all of the dispatch modeling analyses described above:

- BRG Gas Supply Report – Prepared for the Utilities Working Group, June 2023.
- Wood Mackenzie – Alaska Economic Viability Assessment and Economic Value of the Alaska LNG Project – Phase 1, Final Report, October 2024.

This section provides an initial objective overview of the key assumptions, results, and limitations of each study. A table providing a side-by-side comparison is included in the first appendix. We also provide some subjective interpretations of what are the key takeaways from each study as of December 2025.

[7] Provided to ACEP by legislative staff. We are not aware of a publicly available internet link to this study.
[8] Provided to ACEP by legislative staff. We are not aware of a publicly available internet link to this study.

2.1 NREL 2024: Achieving an 80% Renewable Portfolio in Alaska's Railbelt: Cost Analysis

This study considers capacity expansion over decades in addition to hourly dispatch modeling. It provides a strong foundation for understanding how renewables might be integrated into the Railbelt system under an 80% Renewable Portfolio Standard (RPS) by 2040. While it does not attempt to address in detail how reliability would be maintained during the most challenging operating conditions, it does include useful estimates of specific integration costs—such as transmission spur lines, gas storage, and scheduling resources—that would be required to achieve the RPS goal.

Key elements of the study include:

- **Purpose**: Compare the cost of achieving an 80% RPS by 2040 to two alternative scenarios: (1) no new renewables and (2) a "reference scenario" where the model selects the least-cost resource mix through 2040.
- **Modeling approach**: Capacity expansion and resource selection using PLEXOS, with hourly dispatch modeling to confirm that loads can be met each hour.

Key assumptions

- Assumes unified economic dispatch across the Railbelt system.
- Load growth: Baseline load increases 3.7% from 4,686 GWh in 2024 to 4,860 GWh in 2040 (p. 18 from report). An additional 782 GWh is included for electric vehicles, using ACEP's lowest EV growth scenario (reaching 100,000 EVs by 2040). Total load grows ~20% by 2040.
- Transmission: No new transmission is assumed. The Healy-to-Willow transfer path is maxed out for approximately 3,500 hours/year due to wind exports from the GVEA region (Figure 26 in report), suggesting that added transfer capacity could enable more effective sharing of northern wind resources.
- Fuel assumptions: LNG price of $12.10 per MMbtu (2023$) in 2028, escalating at 0.5% per year in real terms.
- Renewable energy costs: Wind energy purchased under a PPA is assumed to cost $70–80/MWh at the wind plant boundary. Integration costs, including transmission spur lines, add ~15%.
- Technology cost assumptions: Based on the 2023 NREL Annual Technology Baseline (ATB) "mid-case," which projects continuing cost declines. An Alaska cost multiplier -- equal to 1.85 and declining over time – is applied to the ATB lower-48 costs.
- **40% Investment Tax Credit drives down the assumed capital cost of renewables**

Results

- Scenario outcomes: The model selects a least-cost portfolio with 76% renewable generation. The 80% RPS scenario requires additional renewable capacity, leading to uneconomic curtailment of some resources—hence, 76% is the modeled least-cost outcome.

- System operation: NREL emphasizes the need for increased ramping from fossil and hydro units to balance variable wind and solar generation.
- Planning reserve contribution: Wind is credited with a modest capacity contribution.
- Integration cost details:
    - Additional integration costs are ~15% above the PPA cost for IPP wind power—approximately $45 million on top of $285 million in total 2040 costs.
    - Gas storage (24 hours' worth) is included, using Railbelt-specific cost estimates.
    - Forecasting and scheduling costs are estimated at $1.5 million/year (~$0.30/MWh).
    - Wind is allowed to provide intra-hour operating reserves through deliberate pre-curtailment (Figure 27 in report), but not contingency reserves for unexpected generation loss.[9]

Key takeaways

The principal NREL 2024 result is that renewables can compete with $12/Mcf gas. This result is directly associated with relatively optimistic assumptions about wind installation costs, including a 40% ITC and projected declines over time in both Lower-48 wind system costs and the Alaska cost multiplier.

The NREL 2024 study does a good job of “covering all the bases” by using both capacity expansion and hourly dispatch modeling, and by calculating spur line costs for specific wind projects. However, NREL 2024 does not include detailed reliability assessments using power system models such as PSS-E that can evaluate particular challenging hours or conditions, and it therefore cannot and does not determine the specific costs of additional equipment, such as batteries, needed to maintain reliability. The study does make a reasonable attempt to allow for the general costs of maintaining reliability by requiring more expensive “grid-forming” inverters on wind resources.[10]

2.2 E3 2024: Railbelt Wind Integration Study

This study provides a detailed and technically rich analysis of what it would take to integrate 300 MW of new wind capacity into the existing Railbelt electric system over the near term—roughly displacing 20% of current thermal generation. The study was conducted under a defined set of operational and infrastructure constraints, some of which were determined by the EPS 2024 study as critical for reliability, and it incorporates assumptions that reflect practices seen in organized electricity markets. A key feature of the analysis is its treatment of gas supply

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[9] NREL’s 2019 report (P. L. Denholm, Y. Sun, and T. T. Mai, 2019. An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A20-73590. https:/doi.org/10.2172/1505934) states that as of 2019 anyway, “Rules for wind providing regulating reserves are unclear, inconsistent, and evolving in U.S. ISO/RTO markets” (Slide 41).

[10] NREL 2024 Section 3.3.6 provides a summary of how reliability and its costs have been addressed.

inflexibility: rather than assuming the availability of gas storage to smooth out variability, the model adheres to strict constraints on gas use subsequent to day-ahead gas commitments. System stability is maintained primarily through the required commitment of specific thermal generators to provide adequate inertia ("grid strength") and operating reserves.

Key elements of the study include:

- **Purpose**: Assess the implications of integrating 300 MW of wind into the existing Railbelt system, with a focus on near-term impacts on operations, dispatch, and cost.
- **Modeling assumptions**:
    - Assumes a unified economic dispatch and single Load Balancing Area, consistent with practices in Independent System Operators (ISOs).
    - Does not explicitly evaluate system reliability under current Railbelt operational practices (p. 7 of study).

Key assumptions

- Transmission: No new transmission is assumed (p. 5).
- Fuel assumptions: LNG prices aligned with NREL—$10/MMbtu in 2025 and $12.20 in 2030 (in 2023$).
- Gas flexibility: Gas supply flexibility is constrained to ±10% of the day-ahead scheduled amount.
- No new batteries are added for renewable integration; flexibility is provided by existing batteries, hydro, thermal units, and wind itself via pre-curtailment.[11]
- Hydro storage resource is not used to move energy between days.[12]
- Stability is achieved primarily through forced commitment of thermal generating units (e.g. North Pole, Nikiski OR Soldotna, SPP OR Sullivan 2A, etc.)[13]
- Operating reserves:
    - The study includes a detailed analysis of the reserves required to manage forecast uncertainty and short-term wind variability—from day-ahead forecasts to real-time conditions.
    - However, uncertainty remains about the need for regulation reserves to cover sub-5-minute variability; operational experience with larger wind projects may be needed to clarify this (p. 82).[14]

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[11] E3 recognizes this point: "Future study should explore the ability of other resources (wind, batteries, synchronous condensers, power electronics, etc.) to supply the reliability services currently provided via the minimum commitment requirements."

[12] "We do not model the movement of hydro energy between days, even though there are opportunities to do so in actual operations, especially at the Bradley hydro facility." (p 20)

[13] ACEP found that this type of operational stability management was more expensive (due to higher fuel consumption) than using other methods such as batteries with grid forming inverters. See also reviews such as: https://www.esig.energy/capturing-the-benefits-of-grid-forming-batteries-a-unique-window-of-opportunity/

[14] "The synthetic 5-minute wind production data for new wind resources does not fully capture the windspeed and power output dynamics that determine an adequate level of regulation reserve capacity within each 5-minute interval. Additional within 5-minute regulation reserves for wind may be necessary in

Results

- "Reliability: At the resolution of 5-minute dispatch, the Railbelt system can be reliably operated with 300 MW of new wind." "No loss of load events and minimal levels of regulation shortages are observed over an entire year of 5-minute operations." "Dynamic stability (voltage and inertia) is ensured by commitment of thermal and hydro units." [15]
- Avoided cost benchmarks resulting from dispatch modeling:
    - To be cost-effective, wind must beat an avoided thermal generation cost of $71–92/MWh (2023$). E3 expresses this as $82–106/MWh in nominal 2030 dollars, assuming 2% annual inflation.
    - These avoided costs reflect both fuel savings and the additional costs of maintaining adequate thermal operating reserves to support variable wind output.
- "Resource operations: Optimal dispatch of batteries, hydro, thermal, and transmission allows for almost all of the 300 MW of new wind to be absorbed." "Batteries can help to balance short-duration fluctuations in wind output but are limited in their ability to balance multi-hour forecast error events." "Hydroelectric resources play a large role in balancing wind because energy stored in reservoirs enables dispatch flexibility. Using hydro resources to balance wind forecast errors is an important operational strategy to cost-effectively integrate wind generation in the Railbelt."[16]
- "Curtailment: …as little as 1% of the wind production potential may need to be curtailed."
- "Transmission between Railbelt zones is a crucial tool for managing wind variability and forecast errors. With Bradley hydro and the HEA battery in the Kenai zone, dispatchable naphtha and oil in the Interior, and fuel-constrained gas in the Kenai and Central zones, dynamic utilization of transmission between zones is important to access the diversity of Railbelt resources."

Key takeaways

This study shows that up to 300 MW of wind can be accommodated by the **existing** Railbelt system – with existing transmission, existing batteries, and existing gas nomination requirements. Reliability and stability can be maintained by using existing battery, hydro, and thermal resources, as specified by the EPS 2024 study. This finding is important because it shows via rigorous modeling that **operational practices can substitute** for expensive additional equipment, albeit at the cost of a higher fuel burn.[17]

Two other takeaways are noteworthy for policymakers. First, the E3 results are a powerful demonstration of how transmission flows and transmission utilization can, and likely will, change dramatically if substantial new inexpensive generation is built.[18] In our view, these simulations

practice relative to what is modeled in this study, though this cannot be confirmed without further study or operational experience." (p 82).

[15] E3 study, p. 7

[16] E3 study, p. 8

[17] E3 study at p. 64 discusses a sensitivity case that saves $14 million per year by relaxing the operational constraints, suggesting that new equipment might be a cheaper way of achieving stability.

[18] See, in particular, E3 Study Figure ES-4 on p. 10.

reinforce the idea that the Railbelt transmission system is a regional network that will serve the entire Railbelt region in different ways over time.

Second, the E3 study models the operation of a single load-balancing area (LBA) that enables (among other things) greater sharing of reserves, coordinated least-cost unit commitment, and co-optimization of energy and reserves on transmission assets without regard to wheeling charges. The single LBA assumption is associated with a $47 million annual reduction in fuel costs compared to the actual system operations in 2022.[19] That reduction is large -- about 15% of total Railbelt fuel costs, or about 1 cent per kWh on a customer's bill. At the same time, it is important to keep in mind that the number was calculated as the "residual" amount remaining after accounting for numerous other cost factors. It was NOT the result of running a head-to-head comparison of "current practices" vs. "single LBA" using the same model. (Current practices were not modeled). Thus, this result must be interpreted with due caution.

2.3 Chugach Electric 2024 Integrated Resource Plan

This study by Chugach Electric focuses on a single utility and offers a good example of how integrated resource planning tools can be used to develop candidate portfolios that are then iteratively refined through stakeholder engagement and expert judgment. Rather than focusing on a single least-cost outcome, the Chugach IRP explores multiple pathways that balance reliability, cost, and environmental goals. While specific power purchase agreement (PPA) prices for wind and solar are not disclosed, the study illustrates how a utility-specific planning exercise can generate substantial renewable additions under plausible assumptions.

Key elements of the study include:

- **Purpose**: Provide a resource roadmap for Chugach Electric Association's future capacity needs; modeling was conducted using the EnCompass software platform.
- **Modeling approach**:
    - Capacity expansion and resource selection using EnCompass.
    - Hourly dispatch modeling used to verify load coverage and evaluate multiple resource portfolios.
    - Assumes continued coordination of dispatch (i.e., power pooling) with Matanuska Electric Association (MEA).

Key assumptions

- Load forecast: Load growth is projected to remain essentially flat.
- Infrastructure assumptions:
    - No new transmission or gas storage included.

[19] E3 study, p. 73

    - Flexible gas supply assumed, without accounting for on-site gas storage costs. The rationale provided is that including such costs would only further favor wind in the model.
- Fuel assumptions:
    - Beluga gas used at $8–$10/MMbtu.
    - LNG priced at $8/MMbtu through 2028, then escalates to $12.20/MMBtu in 2023$ ($14/MMbtu in nominal dollars), then remains constant in real dollars.
    - It is unclear whether LNG serves as the marginal cost benchmark for evaluating renewable competitiveness.
- Renewable cost assumptions: Not disclosed for wind or solar PPAs.
    - Treatment of Dixon Diversion: Included manually in half of the scenarios (16 of 32), excluded in the other half

Results

- Resource portfolio results:
    - In "Expansion Planning Analysis" with "No forced projects," the model selected 260 MW of wind and 120 MW of batteries between 2025–2034 (Table 7).
    - "Preferred Portfolio" (Portfolio 2) includes: Dixon Diversion project; 254 MW of wind; 90 MW of batteries; Additional unspecified "Generic Reg" batteries for wind regulation[20]
    - Portfolio results are presented using "swim lanes" (with and without Dixon), with the Dixon "swim lane" showing slightly lower system Net Present Value (NPV) costs.
- Thermal resource utilization: More than 400 MW of existing gas capacity would be used for only ~8 hours per year, suggesting potential for mothballing (p. 47).
- Carbon reduction goals: Chugach has stated goals for carbon reduction, but these were not used as explicit constraints or drivers in the modeling framework.

Key takeaways

The Chugach IRP provides corroboration of the general proposition that wind resources are "in the ballpark" under a multi-criteria planning approach. The Public Version of the study does not provide sufficient detail to assess particular assumptions about technology costs and how they relate to the rankings of specific portfolios. In particular, the Dixon Diversion cost is listed as only $193 million (vs current estimates of about $342 million[21]). But the $193 million number might refer to a pro-rata share of the project applicable to Chugach.

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[20] Chugach assigned a requirement that each MW of wind be matched by one MW of batteries as a proxy for required regulation resources and costs. (IRP page 14)

[21] https://www.akenergyauthority.org/Portals/0/Presentations/2025.08.22%2520AEA%2520Dixon%2520Diversion%2520Project%2520Update%2520to%2520CEA%2520Board%2520of%2520Directors%2520(Final).pdf

2.4 ACEP 2024: Railbelt Scenarios for 2050

This study is distinctive for its explicit focus on grid reliability under high-renewable, high-load conditions far in the future. It is the only study to make extensive use of PSS/E stability modeling[22] to identify specific reliability resources—such as grid-forming batteries—needed to support stable operations when inverter-based resources (IBRs) like wind and solar dominate generation. It is also the only study to assess the role of expanded transmission capacity across Railbelt regions and. Rather than projecting the most likely future, this analysis explores whether a much larger electric load in 2050 could be served reliably with minimal fossil fuel use, and what infrastructure would be needed to do so.

Key elements of the study include:

- **Purpose**: Explore how a significantly larger 2050 Railbelt load could be served primarily with non-fossil resources, with particular attention to maintaining system stability on a relatively weak and fragmented grid.
- **Modeling approach**: Models the entire Railbelt in 2050 under a unified economic dispatch framework, with regional constraints between the South, Central, and Northern systems.

Key assumptions

- Load assumptions: Load roughly doubles by 2050, driven by high EV adoption and moderate heat pump uptake. This aggressive load scenario was deliberately selected to test system capability under high-stress conditions.
- New baseline infrastructure assumptions: Bernice–Beluga HVDC line; Kenai–Anchorage transmission upgrade to 230 kV; Dixon Diversion hydro project; 228 MW of residential solar; Retirement of Healy Unit 2.
- Fuel assumptions: LNG priced at $14/MMbtu (2023$).
- Renewable cost assumptions: Based on 2030 moderate-cost projections from NREL's 2021 ATB. Alaska-specific multipliers applied; the wind multiplier is 1.9. No assumed cost reductions are assumed beyond 2030. A **30% Investment Tax Credit drives down the assumed capital cost of renewables**.
-
- Modeling tools:
  - Resource sizing: optimization of the resource mix via a custom MATLAB tool.
  - Hourly dispatch: PLEXOS.
  - Grid reliability and stability: PSS/E simulations.
- Scenario development: Initial scenarios explored a wide range of resource mixes, including Watana hydro, Cook Inlet tidal, and small modular nuclear. A final scenario focused on wind and solar, avoiding dispatchable technologies with high capital costs.

[22] The EPS study that provided inputs to the E3 wind integration study likely used PSS/E or similar models.

Results

- Economic findings: A mix of wind, solar, and existing thermal could meet 77% of the doubled 2050 load at a cost within 4% of a base-case thermal scenario—after accounting for new reliability infrastructure (primarily batteries).
- Reliability assessment: PSS/E modeling identified grid-forming inverters as essential for reliable operation during “most challenging” conditions, when wind and solar output is high and synchronous generation is minimal.
- Transmission analysis: ACEP 2024 is the only study to incorporate new transmission links, showing how they could play a key role in a stable and cost-effective high-renewables, high-load system.[23]

Key takeaways

The principal result of this study is that “big is possible” – A **doubled** Railbelt load can be served reliably with a diverse mix of generation resources, whether that mix includes new hydro, wind, solar, nuclear, tidal or others. A doubled load would allow Alaska to achieve greater energy security by serving significant heat and transportation needs with locally-produced energy, or perhaps serving large new industrial loads that boost the economy.

A second key takeaway is that significant dispatchable generation (whether thermal, hydro, or flexible-output nuclear) is likely to be needed to cost-effectively operate the Railbelt system even in 2050.

2.5 EPS 2024. Railbelt Wind Integration Study.

The EPS 2024 study serves as a technical input to the E3 Wind Integration Study and is best understood as a companion analysis. While not a standalone planning document, it played a critical role in defining operational constraints that shaped the E3 modeling outcomes.

According to E3, “The EPS study focuses on maximum wind output and minimum load conditions to determine the minimum number of units that must be committed in each zone of the Railbelt” (E3, p. 21). These constraints—derived from stability and operational assessments under high-wind, low-load scenarios—were used to inform the E3 dispatch modeling. A summary of the resulting unit commitment requirements appears on page 22 of the E3 report.

Because of its technical scope, EPS 2024 is best viewed as a supporting analysis that helped quantify the real-world constraints utilities may face when integrating substantial wind resources without compromising reliability.

[23] It is important to understand that ACEP 2024 *assumed* the transmission upgrades; it did not select them as part of any optimizing exercise.

2.6 Railbelt Utilities 2022: Compliance Cost Impacts Prefeasibility Analysis

This draft prefeasibility study, developed by 1898 & Co. (a subsidiary of Black & Veatch), explored the potential cost and resource implications of meeting various carbon reduction and renewable energy targets on the Railbelt grid over the next 20–30 years. Although it lacked the dispatch modeling and system-level rigor of later studies, it offered an early scoping-level view of possible pathways for reducing CO_2 emissions, anchored in spreadsheet-based scenario modeling. Due to the large number of variables and sensitivity cases—and the fact that it was not finalized—its conclusions are difficult to generalize, but the study generally found that compliance with aggressive decarbonization goals would be more expensive than continued reliance on fossil fuels.

- **Purpose**: assess effects on costs and resource mix of achieving prescribed levels of CO2 emissions.
- **Modeling approach**: Spreadsheet-based scoping model; No hourly modeling of grid operations.

Key assumptions

- Resource and technology assumptions:
  - Evaluated a wide range of generation technologies: wind, solar, geothermal, hydro, tidal, nuclear, hydrogen + gas, and gas + carbon capture.
  - Scenarios were anchored by specific technology pathways (e.g., Susitna hydro, small modular reactors, wind) (p. 12).
  - Generic wind sites assumed to require 10 miles of new transmission per 70 MW of capacity.
- Load growth assumptions: 1% annual growth for MEA; 0% growth for other utilities.
- Cost assumptions:
  - Technology costs from 2021 NREL ATB and proprietary estimates.
  - Cost inputs appear broadly consistent with those used in ACEP 2024 (e.g., $32/kW-year is assumed in both studies for battery fixed O&M).
- Regulation proxy: Assumes 1 MW of battery storage required per 1 MW of wind/solar to provide regulation—a simplified method also used in the Chugach IRP (p. 14).

Results

- Notable findings: Among the compliance scenarios, the 80% renewable energy target by 2040 was found to be the least costly. Also, a nuclear-focused mix – with nuclear deemed renewable -- was found to be less expensive than thermal generation in one scenario. (p. 30)

3. Recent events and recent actual cost data

3.1 Loss of the Investment Tax Credit

Federal law enacted in July 2025 abolished the Investment Tax Credits of 30-40% that underlie the renewable technology capital costs used in ALL of the studies reviewed above. The ITC remains available to projects commenced prior to July 4, 2026 or completed before the end of 2027, and it appears that Chugach Electric is planning to meet this deadline with its recently announced Beluga Solar Project.

3.2 New data on the cost of renewable generation

Chugach Beluga Solar

The Chugach Beluga Solar Project has 10 MW (AC) of capacity with an estimated capital cost disclosed by the Chugach Board of $26.4 million prior to applying the ITC and $15.9 million after the anticipated application of a 40% ITC.[24] Assuming a 5% interest rate for debt financing and a 13% capacity factor, this project will provide electricity at a constant nominal dollar cost of about 10 cents per kwh. The installed cost will be $1,586 per kW (presumably in 2026-2027 dollars), which can be compared to $1,308 per kW in 2023$, which was assumed by ACEP using the NREL 2023 ATB and a 1.5x Alaska multiplier.

Recent Lower-48 PPA prices for wind energy

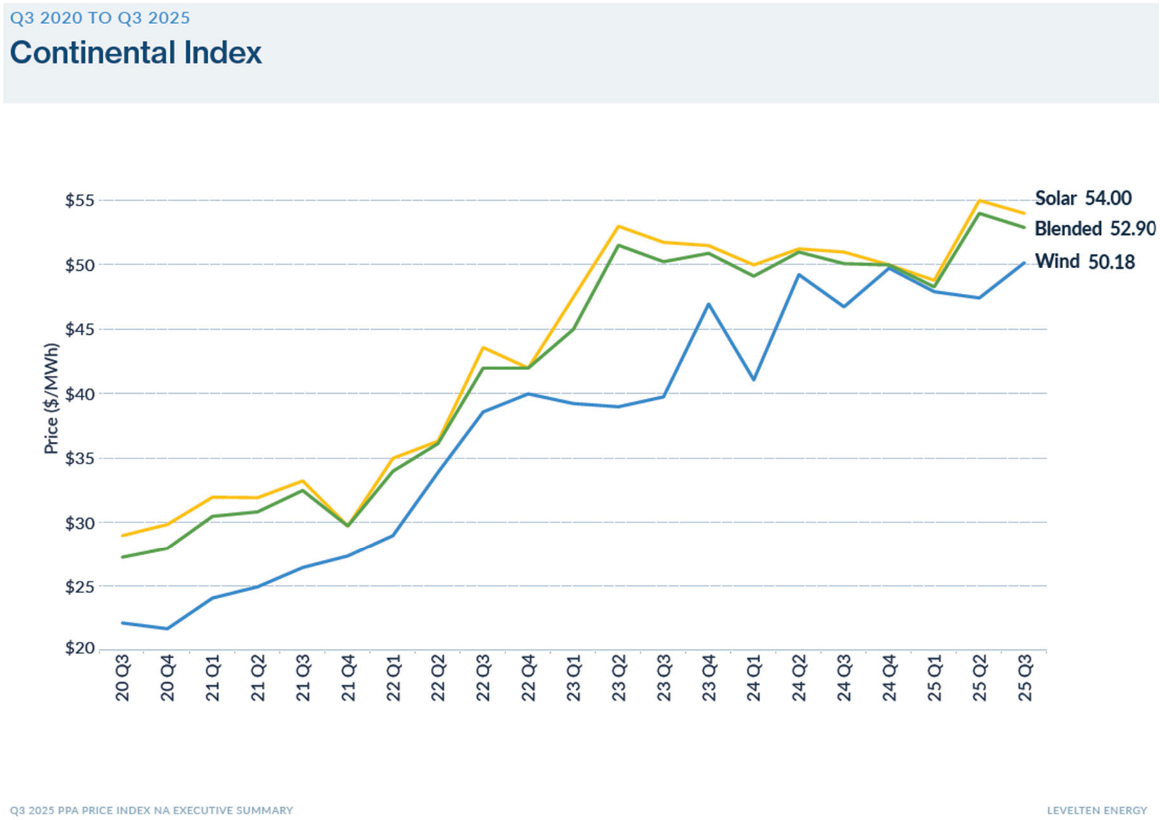
LevelTen Energy maintains a database of recent and current PPA offers to sell wind power for a fixed price under long-term contract.[25] A publicly available subset provides quarterly data on actual PPA prices being offered in U.S. wholesale markets. The publicly reported prices are the so-called P25 prices, which represent the price at the 25th percentile when all prices are arranged from low (zeroth percentile) to high (100th percentile). By aggregating regional data in different ways, LevelTen produces a lower and a higher value of the P25 price each quarter.

Figure 2 reproduces the LevelTen data for the lower values of wind and solar PPA prices, in nominal dollars.

[24] Chugach Board 10/22/25 meeting, un-numbered Resolution at page 40/43 of Board packet: https://www.chugachelectric.com/sites/default/files/meetings/document_packets/10%2022%2025%20RBM%20-%20Public%20Packet%20-%20POST.pdf

[25] https://www.leveltenenergy.com/ppa# We are grateful to Ed Jenkin, Railbelt Reliability Council CEO, for alerting us to this dataset.

Figure 2. LevelTen Energy PPA prices for wind and solar energy 25th percentile, lower value

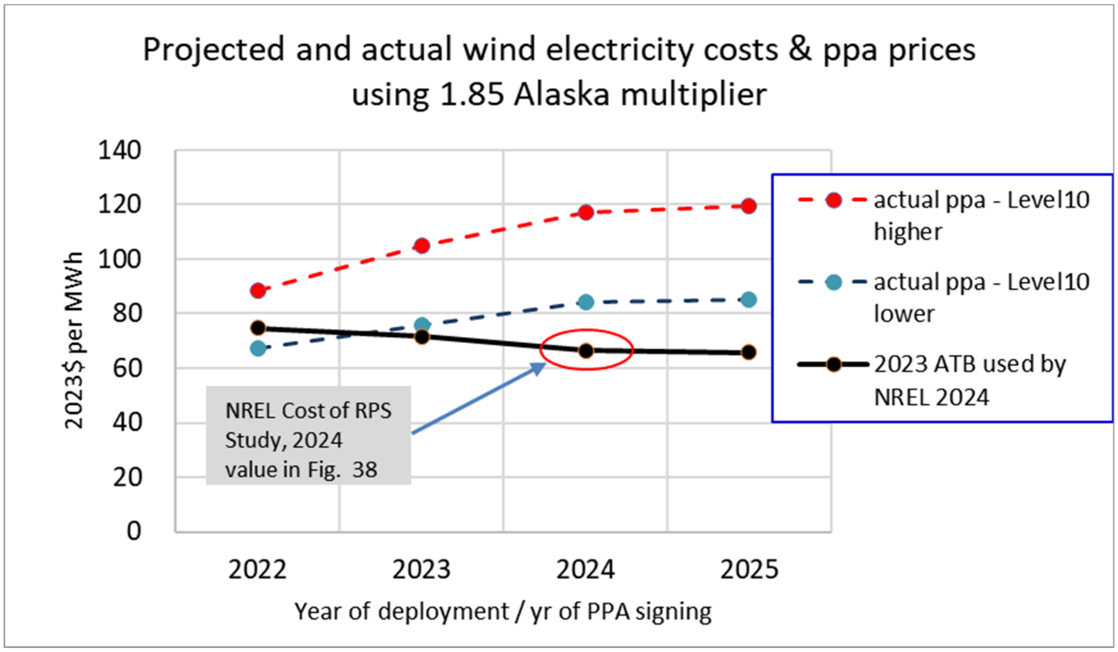


Source: LevelTen Energy. https://www.leveltenenergy.com/ppa#

The main takeaway from these data seems to be the **doubling** of U.S. wind PPA prices since 2020.

We conducted further analysis to make an apples-to-apples comparison of these data with the ATB projected wind costs that went into the NREL 2024 RPS Cost Analysis. The resulting comparison is shown in Figure 3. In this figure the LevelTen data have been converted to 2023$ and "Alaskanized" by applying a 1.85 multiplier (as NREL did).

Figure 3. LevelTen Energy PPA wind prices compared to NREL 2024 wind costs



The data are shown in Table 1.

Table 1. LevelTen Energy PPA wind prices compared to NREL 2024 wind costs
2023$ per MWh

	2022	2023	2024	2025
actual ppa - Level10 higher	89	105	117	120
actual ppa - Level10 lower	67	76	84	85
2023 ATB used by NREL 2024	75	72	67	66

Note to table: actual PPA data for 2025 includes only Q1-Q3

These comparisons suggest that while the ATB estimates from the 2023 ATB, which both NREL and ACEP used for the cost assumptions, were consistent with actual PPA prices in 2022 and 2023, the actual PPA prices are now significantly higher. Furthermore, it is likely that even the 2025 actual PPA data reflects the application of the ITC, which is going away. As LevelTen notes, “only a limited number of planned projects will be able to begin construction in time to secure tax credits — without which, PPA economics will move into unknown, and undoubtedly more expensive, territory.”[26]

[26] https://www.leveltenenergy.com/ppa#

4. The Importance of Load Growth

All of the studies reviewed—except for ACEP's Railbelt Scenarios for 2050—assumed either flat or modestly increasing load growth. For example, NREL 2024 projects an annual growth rate of 1.2%, totaling roughly 20% by 2040. In contrast, ACEP assumes a doubling of load by 2050, driven primarily by electrification of transportation and heating. While modest growth assumptions may be appropriate for near- and medium-term planning, consideration of more substantial load growth could be an important area of focus for state policy. Electrification "crosses boundaries" between traditional electric load, transportation, and heat—offering a structural opportunity to stabilize or reduce rates, while enabling higher levels of renewable generation.

To illustrate the potential rate implications of major load changes, we conducted a simple thought experiment using public data from the Golden Valley Electric Association (GVEA) service territory.[27] In 2023, GVEA sold 571 gigawatt-hours (GWh)—approximately 46% of its total retail sales—to eight large customers under its GS-3 "Industrial Service" rate schedule. This group includes major energy users such as the Fort Knox and Pogo mines.

What if this industrial load were to disappear? GVEA would first lose approximately $72 million in Cost of Power Adjustment (COPA) revenue. However, this loss would be directly offset by a corresponding reduction in fuel and purchased power costs. The more significant impact would come from the loss of over $41 million in base rate revenue—funds that help cover the non-fuel costs of operating the utility. In the short term, these fixed costs would remain, and the $41 million would need to be recovered from the remaining 662 GWh of retail sales. Simple arithmetic yields a required rate increase of approximately 6.2 cents per kilowatt-hour. In a system with already high rates, an increase of this magnitude would be a major financial shock—both for residential customers and the broader regional economy.

[27] GVEA Annual Report to the RCA for 2023, and GVEA Simplified Rate Filing dated 3/19/2024. Both were obtained from rca.alaska.gov.

Appendix A. Comparison Table

	E3 2024	NREL 2024	ACEP 2024	Chugach IRP 2024	Railbelt 2022
Purpose	Examine effects of adding 300 MW wind to existing system by 2030.	determine cost difference between BAU, least-cost reference, and 80% renewable by 2040	Examine high-load, high-renewables scenarios for 2050; emphasis on detailed reliability analysis	Traditional least-cost planning exercise; shows how multiple portfolios can be developed in parallel	Generl scoping exercise examining cost to meet RPS & carbon targets
Time horizon	2025-2030	2025-2040	2050 snapshot	2024-2050	2023-2050
Type of model(s)	day-ahead, 1-hour, and 5-minute dispatch modeling (Plexos)	capacity expansion from 2025-2040 and hourly dispatch (Plexos)	hourly dispatch (Plexos) and separate reliability analysis (PSSE)	capacity expansion and hourly dispatch (EnCompass)	spreadsheet model with monthly granularity. NO dispatch model
Load growth (base case)	Uses 2022 load	Load grows 20% to 5,642 GWh by 2040	Load doubles to 8,704 GWh by 2050	Flat or declining load	MEA 1%/yr, others flat.
LNG price per mcf (same as per mmbtu)	Same LNG price as NREL, expressed as $14 in nominal $ in 2030	12.10 in 2023$ in 2028, then 0.5%/yr increase in 2023$	$14 in 2023$	$14 in 2030 (about $12 in 2023$), then escalates 2.5%/yr nominal	
Generation technologies considered	wind	wind, solar, RoR hydro 25MW, geothermal 100MW, coal, [offshore wind]	Wind, solar, hydro, nuclear, tidal	Wind, solar, hydro, nuclear	Multiple, including nuclear and large hydro
New transmission	No new transmission	No new transmission	Nikiski-Beluga HVDC, upgrade Willow-Healy to 230kV	No new transmission	
Dixon Diversion	Dixon not included	Dixon not included	Dixon assumed to be built in 2027	Dixon included in preferred portfolio	
Base (U.S.) Technology capital costs "CAPEX"	N/A - E3 study did not estimate renewables build costs	NREL 2023 ATB moderate cost trajectory	2021 costs from NREL 2021 ATB	Confidential; New wind = $4,300/kW; new solar $110/MWh	from NREL 2021 ATB
Alaska cost multiplier	NA	Alaska multipliers decline from 1.5-1.9 in 2024 to 1.3-1.6 in 2040	Alaska multipliers = 1.95 (wind), 1.5 (solar), 1.25 (batteries)		
Tax credits	NA	40% ITC (or PTC if greater)	30% ITC	not sure	
Regulation of wind	deailed analysis; thermal capacity committed to reg. up reserves	Incorporated into hourly dispatch and power flow modeling	Incorporated into hourly dispatch and power flow modeling	Requires 1 batter MW per wind MW as proxy for reg costs	Requires 1 batter MW per wind MW as proxy for reg costs
Wind interconnection cost		$17.7/kW-mi (Appx C), or $12.3M per 70 MW@10mi			10 mi per 70 MW, @$1M/mi, or $10M per 70MW@10mi
Solar interconnection cost		22$/kW			
Renewables capacity credit?		Wind=10% of nameplate, solar=0			
Battery cost		$1,700 -> 1,000 "overnight" capex cost in 2023$	$1,122 "rate base" capex per kW for 2-hr battery		
Battery fixed O&M		43/kW-yr in 2024 --> 24 in 2040	32/kW-yr		

Appendix B. Discussion of Recent Policy and Economic Changes

Since January 2025, the Trump administration has enacted a series of policy changes that have significantly increased uncertainty for renewable energy projects. While these shifts impact all projects to some degree, they disproportionately affect independent power producers (IPPs), which depend on stable cash flows and typically lack the financial flexibility of utility-owned entities. The administration's actions—including funding suspensions, expanded tariffs, and executive orders targeting clean energy—have introduced new risks that could result in project delays or cancellations, increased development costs, and diminished investor confidence. These challenges are particularly acute for IPPs, which have limited ability to absorb financial shocks or adjust project timelines.[28]

1. Suspension of Clean Energy Funding and Repeal of Tax Incentives

On January 20, 2025, President Trump signed Executive Order 14154, titled "Unleashing American Energy," which directed federal agencies to immediately pause the disbursement of funds appropriated through the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA). This directive halted grants, loans, contracts, and other financial incentives tied to clean energy initiatives, pending a 90-day review to ensure alignment with the administration's energy policies [1, 2].

Both the Investment Tax Credit (ITC)—applicable to solar, wind, geothermal, and energy storage—and the Production Tax Credit (PTC) for wind and other renewable resources were repealed in July 2025. They are still available for projects started by July 4, 2026 or completed by the end of 2027.

2. Expansion of Tariffs on Renewable Energy Components

Recent federal trade actions have significantly increased uncertainty around the cost and availability of key components for renewable energy projects. In early 2025, the administration substantially increased tariffs on solar materials and components imported from China. These include combined anti-dumping and countervailing duties that, in some cases, exceed 100% for major suppliers of solar modules and cells. The intent of these measures is to address trade imbalances and promote domestic manufacturing, but the near-term effect has been a sharp rise in the projected cost of imported solar equipment [3,4].

This is especially impactful given that a large share of U.S. solar components—including essential materials like polysilicon, wafers, and cells—are sourced from China. The tariffs add to

[28] Utility-owned projects, backed by larger financial resources and diversified portfolios, may be better equipped to navigate these uncertainties. They can often absorb short-term losses and have more flexibility in adjusting to policy changes. However, this general proposition needs to be applied with care to the Railbelt, which has relatively small cooperatives whose members are both customers and owners.

existing supply chain constraints and complicate procurement planning for developers, many of whom had relied on falling equipment costs to make projects pencil out financially.

Additional tariffs on construction materials such as steel and aluminum, which are used in solar racking systems and wind infrastructure, further compound these challenges. These policy shifts have introduced both cost escalation and delivery uncertainty for renewable energy projects across the country [5].

In Alaska, where access to competitively priced, domestically manufactured components is limited and shipping costs are already high, these developments are particularly problematic. For independent power producers (IPPs), in particular, the volatility in materials pricing can delay project timelines, impact financing terms, and erode the economic viability of planned projects. While longer-term effects may depend on how domestic supply chains respond, the current environment has clearly disrupted expectations around cost and delivery—injecting a significant degree of risk into project planning and investment decisions.

3. Rising Construction and Labor Costs

The construction industry across the United States has experienced significant cost escalations in recent years, driven by rising prices for materials, a shortage of skilled labor, and logistical constraints. In Alaska, these challenges are further amplified by high transportation costs, seasonal access limitations, and a smaller contractor base. Engineering, Procurement, and Construction (EPC) bids for recent renewable energy projects in the state have anecdotally come in at nearly twice the anticipated cost, reflecting both national inflationary trends and localized capacity constraints.

These pressures are not limited to the renewable sector but are affecting all construction-intensive projects. For example, the Sterling Highway Improvement Project saw its estimated cost more than double since 2018—reaching $840 million—largely due to inflation and supply chain disruptions [6, 7]. For independent power producers (IPPs), the combination of rising construction costs and policy-induced uncertainty makes it more difficult to plan and finance new renewable energy projects. Volatility in material pricing and labor availability can delay project timelines, influence financing terms, and undermine overall project viability. This uncertainty is increasingly being incorporated into financial modeling and risk assessments, ultimately affecting the pricing, structure, and feasibility of IPP-led developments.

4. Underperformance of Installed Systems

In Alaska, several recent solar installations have delivered less energy than originally modeled, raising concerns about the reliability of performance estimates used in project planning and financing. Anecdotal reports, including from the Willow solar farm, suggest production shortfalls of up to 20% below expectations. While limited formal data exist for Alaska-specific projects, this pattern aligns with broader national findings in colder and lower-irradiance regions, where snow accumulation, panel soiling, and suboptimal siting often contribute to reduced output.

Nationally, research from the National Renewable Energy Laboratory (NREL) and other institutions has shown that performance modeling tools may not always capture site-specific losses in subarctic environments, particularly in projects where irradiance data is sparse or environmental factors—such as snow cover duration—are underestimated [8,9]. In Alaska, these uncertainties are magnified due to the state's unique solar resource profile, limited monitoring infrastructure, and lack of long-term historical performance data.

For independent power producers (IPPs), underperformance directly affects project economics by reducing revenue, lengthening payback periods, and increasing the perceived risk of future investments. These discrepancies also complicate financing discussions, as lenders and investors become more cautious in underwriting expected energy yields. In combination with recent federal policy shifts—such as tariff increases and uncertainty around tax credits—performance variability adds another layer of risk that IPPs must account for in both technical design and financial modeling.

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Acronyms / Glossary

ATB	Annual Technology Baseline, an annual dataset published by NREL
IPP	independent power producer
ISO	independent system operator
ITC	Investment Tax Credit
GWh	gigawatt-hour, equal to 1 million kWh or 1,000 MWh
kWh	kilowatt-hour, a basic unit of electric energy
Mcf	thousand cubic feet (sometimes written mcf)
MMbtu	million btu (sometimes written mmbtu). One million btu essentially equals 1 thousand cubic feet of natural gas
MWh	megawatt-hour, equal to 1,000 kilowatt-hours
NREL	National Renewable Energy Laboratory (renamed to “National Laboratory of the Rockies on 12/4/2025)
PPA	power purchase agreement
PTC	Production Tax Credit

Draft: 5-16-25

Prepared by: Gwen Holdmann

Residential Rate Trends: Kodiak Electric Association vs. Railbelt Utilities

Overview

This report examines the historical trends in residential electricity rates for Kodiak Electric Association (KEA) compared to the average rates of Railbelt utilities. KEA, notable for generating nearly 100% of its electricity from renewable sources, maintained flat rates for nearly three decades before implementing a rate increase in 2023. The Railbelt region, by contrast, reflects a more typical trend of rising rates over time, largely influenced by fuel price volatility and system-wide cost increases.

KEA Background

Kodiak Electric Association (KEA) was formed in 1941 as a member-owned rural electric cooperative to bring reliable electric service to Kodiak Island, Alaska. Originally reliant on diesel generation, KEA was later able to diversify its power supply through the construction of the Terror Lake Hydroelectric Project—one of four hydro assets developed by the State of Alaska under the Four Dam Pool program. While the project had long been foundational to KEA's power system, ownership was not officially transferred to KEA until 2009, following a broader restructuring of the Four Dam Pool assets[1].

Although hydro has played a central role in KEA's operations, it has never been able to fully meet year-round demand on its own. In 2007, KEA adopted a formal goal of achieving over 95% renewable energy by 2020 and began expanding its renewable energy portfolio. In 2009, KEA installed its first three 1.5 MW GE wind turbines at Pillar Mountain, followed by three more turbines in 2012, bringing the total wind capacity to 9 MW. In 2014, the utility completed installation of a third hydro turbine at Terror Lake, increasing the facility's capacity from 22 MW to 31 MW and enabling it to meet a greater share of peak demand. This was coupled with an expansion of the system's hydrological input via the Hidden Basin Diversion, which was completed in 2019 and redirected additional water into the Terror Lake reservoir. These

[1] The sale of the Four Dam Pool assets by the State of Alaska was authorized by the legislature in 2000, resulting in the transfer of ownership of the hydroelectric projects to a regional joint action agency, which was later restructured as the Southeast Alaska Power Agency (SEAPA). Proceeds from the sale were used to establish the Power Cost Equalization (PCE) Endowment Fund.

improvements enhanced the utility's ability to dispatch hydropower more flexibly across seasons and allowed KEA to further reduce reliance on diesel generation while supporting the integration of variable wind energy and managing load demands more effectively throughout the year.

To support the integration of variable wind energy and ensure system reliability—particularly for large industrial loads like the port's electric crane system—KEA installed two ABB PowerStore flywheels and a 3 MW lithium-ion battery system. These upgrades have allowed KEA to minimize its reliance on diesel fuel. Since 2014, the utility has reported that more than 99% of its annual electricity generation is met through hydro and wind resources. Diesel generators remain in place for contingency use, primarily during maintenance or unusual reliability events.

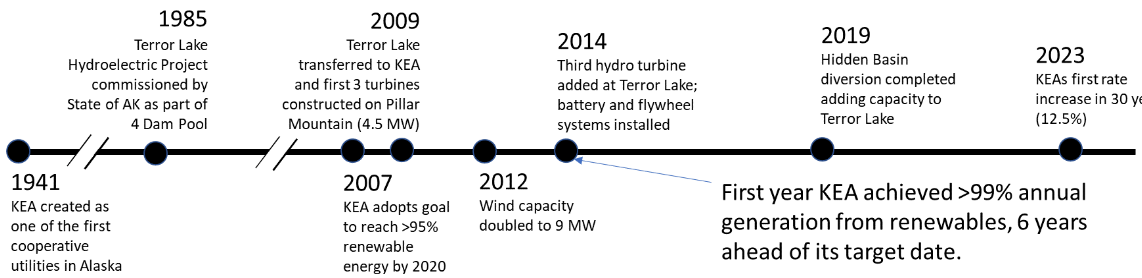

Figure 1. Timeline of key events in KEA's history.

Evolution of KEA Electric Residential Rates

Figure 2 shows that Kodiak's residential rates, adjusted to 2021 dollars, have gradually declined over time, with a notable drop following the transfer of the Terror Lake hydro project to KEA and the installation of its first wind turbines in 2009. Over this period, diesel generation (gray) was largely displaced by hydro (blue) and wind (yellow). The addition of a third hydro turbine at Terror Lake and the doubling of wind capacity to 9 MW—along with the integration of energy storage and a flywheel—facilitated the transition to nearly 100% renewable generation beginning in 2014.

KEA has reported that its estimated cost of wind generation is approximately 11 cents per kilowatt-hour. For hydropower, the utility previously purchased energy from the Terror Lake facility at a rate of 6.8 cents per kilowatt-hour under the Four Dam Pool ownership structure. Since acquiring full ownership of the project in 2009, KEA estimates its current cost of hydroelectric generation to be lower—around 5 cents per kilowatt-hour.

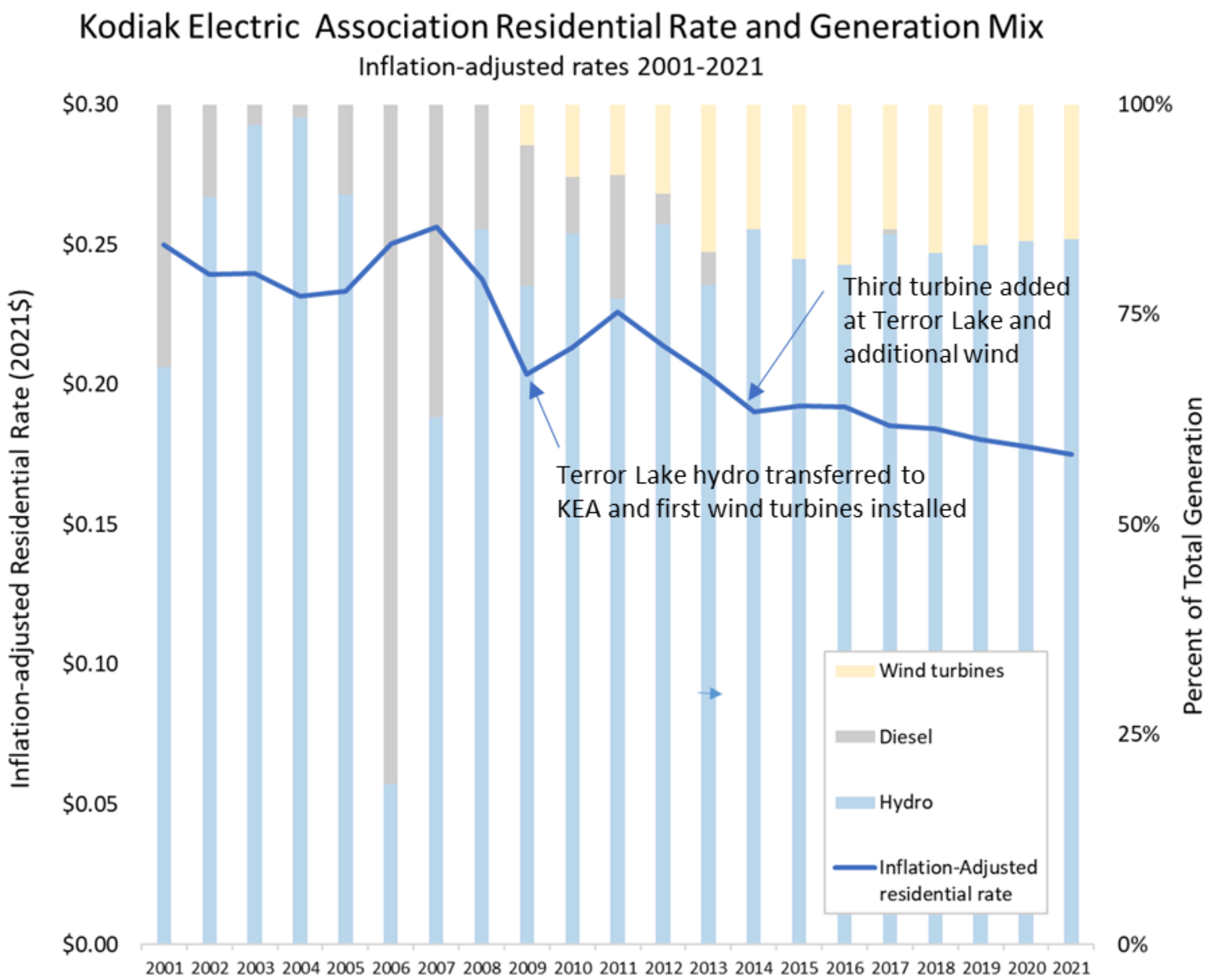

Figure 2: Inflation-adjusted residential electricity rates and generation mix for Kodiak Electric Association, 2001–2021. A sharp increase in diesel generation in 2006–2007 corresponds with a scheduled maintenance outage at the Terror Lake hydro facility, compounded by a low water year. Figure produced by Neil McMahon (DOWL) for ACEP.

Key Factors Behind Kodiak's Low and Stable Rates

KEA maintained a flat base residential electricity rates between 1996 to 2023, a notable achievement given inflation and rising utility costs across the state. This rate stability is primarily attributed to KEA's shift away from fuel-based generation, significantly reducing exposure to volatile diesel prices. However, operational strategies and system design choices have also played a key role. Key factors include:

1. <u>Minimal Dependence on Imported Fuel:</u> KEA's energy portfolio is dominated by hydro and wind resources, nearly eliminating the need for diesel fuel. As a result, KEA has been largely insulated from fluctuations in global fuel prices. Rate adjustments over the past decade were limited primarily to changes in the Cost of Power Adjustment (COPA), driven by minimal diesel usage.

2. Availability of Storage Hydro. KEA benefits from the availability of storage hydro at the Terror Lake facility, which provides year-round generation capability and operational flexibility. Unlike run-of-river hydro systems—such as those used in Cordova—storage hydro allows KEA to regulate the timing and output of generation based on system demand. This ability to store and dispatch water as needed enables KEA to smooth out fluctuations in wind generation and maintain reliability during periods of low renewable output or peak load conditions. The year-round availability of dispatchable hydropower is a key asset in KEA's ability to operate with minimal reliance on diesel.

3. Implementation of Operational Efficiencies: According to the former CEO Darron Scott, KEA has implemented several internal strategies to reduce operating costs, particularly in workforce management. Labor is a significant expense for electric utilities, but KEA has adopted a more streamlined operating model that has helped offset cost pressures seen across the broader utility sector. Key measures include:

   - Staffing Optimization: Over the past 20 years, the utility has slowly reduced its workforce from approximately 60 employees to around 30, primarily through retirements and natural attrition. The has been enabled automation and consolidation of job functions, although some functions such as linemen have not seen this same reduction in force.
   - Technological Integration: KEA has adopted modern control systems and automation to improve operational efficiency and reduce labor requirements. These tools support real-time coordination across renewable and storage assets, enabling a stable and responsive microgrid without increasing staffing levels.
   - Cross-Training: Operators are trained to manage hydro, wind, and diesel systems, allowing for a more flexible and efficient use of staff.
   - Targeted Contracting: KEA uses external contractors—such as GE—for specialized repairs, further reducing the need for in-house technical capacity.

4. Lower Regular Maintenance Costs. Internal analysis at KEA indicates that the hydro-wind-storage system has lower routine maintenance costs than its former diesel-based system. Diesel maintenance previously cost the utility an estimated 1 cent/kWh—higher than current costs for the renewable system. KEA notes they have largely avoided expensive maintenance outages, with only one gearbox replacement at the Pillar Mountain wind farm since its commissioning in 2009. While the potential for significant capital repairs remains, KEA's maintenance record reflects both a proactive approach and, by their own account, a degree of good fortune.
5. Strategic use of funding opportunities. KEA has actively leveraged external funding and financing tools to support its transition toward renewables while minimizing impacts on ratepayers. The utility has successfully pursued federal and state grants, secured favorable financing and refinancing terms, made strategic use of Clean Renewable Energy (CREB) bonds and phased major projects, including both improvements at Terror Lake and the Pillar Mountain Wind Project, in a way that aligned with available resources and avoided sudden cost burdens. These strategic decisions have contributed to KEA's ability to modernize its system while maintaining long-term rate stability.

Railbelt Comparison

In contrast to KEA, the Railbelt utilities remain heavily dependent on natural gas for electricity generation. Hydropower accounts for only about ~15% of total generation capacity across the Railbelt. While incremental improvements—such as the deployment of more efficient gas turbines and the addition of limited wind and landfill gas resources—have modestly reduced reliance on natural gas, these gains have been outweighed by rising gas prices. As a result, inflation-adjusted residential electricity rates across Railbelt utilities have generally trended upward, increasing by approximately 25% to 75% since 2001.

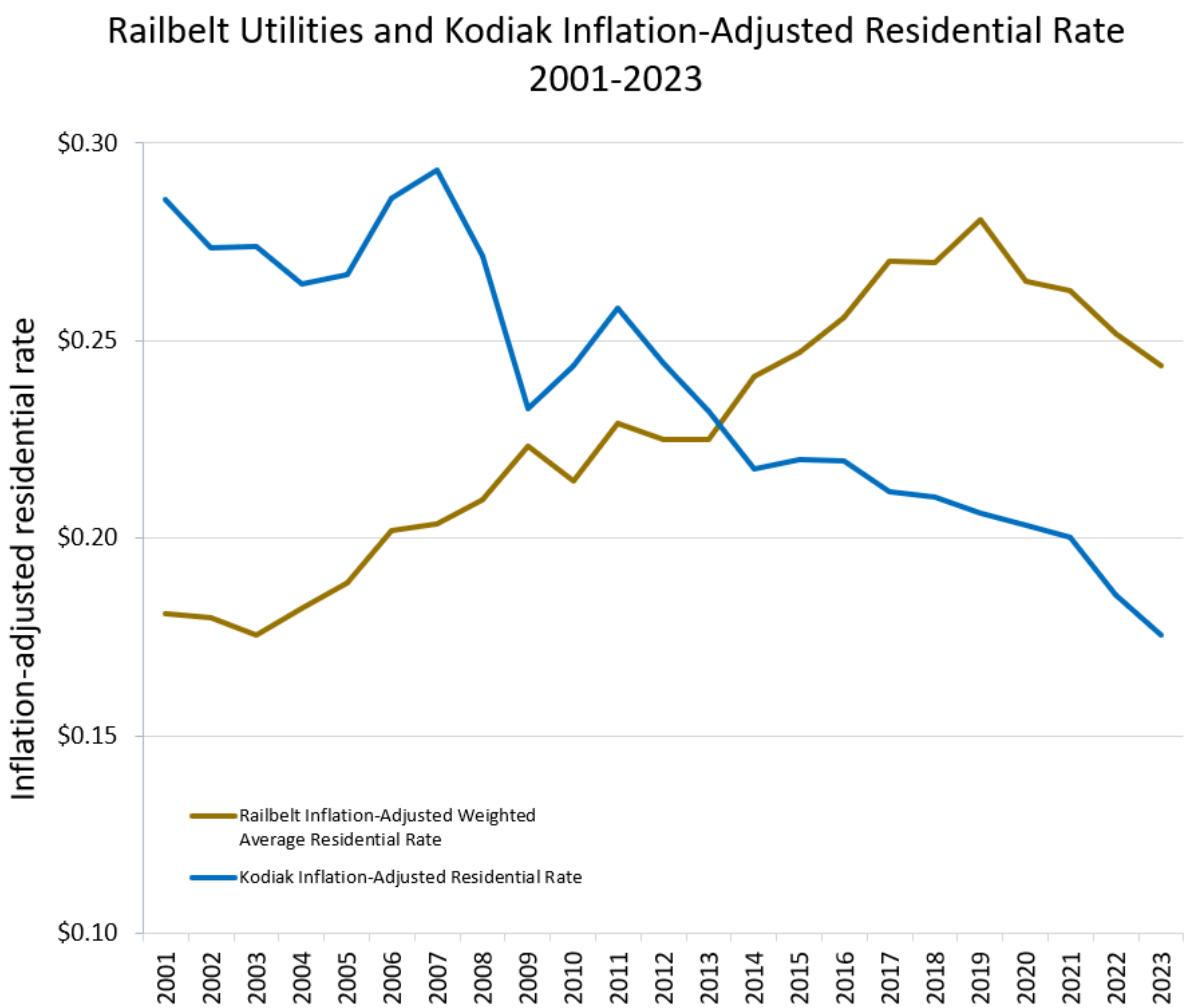

Figure 3: Inflation-adjusted residential electricity rates for Railbelt utilities and Kodiak Electric Association, 2001–2023. This chart illustrates how residential rates have evolved over time across the five major Railbelt utilities—MEA, GVEA, HEA, CEA, and the former ML&P—compared to Kodiak. While Kodiak had the highest rate in 2001, it had the lowest by 2021, reflecting the long-term impact of its shift to renewable energy and stable cost structure. In contrast, rates across the Railbelt generally increased over the period, largely due to continued dependence on natural gas and rising fuel-related costs. Figure produced by Neil McMahon (DOWL) for ACEP.

Conclusion

Kodiak Electric Association's ability to maintain flat residential electricity rates for three decades stands out in Alaska's energy landscape. This outcome is the result of early and sustained investments in renewable energy, the adoption of a lean and adaptive operational model, and an intentional strategy to minimize exposure to fuel price volatility. In contrast, utilities on the Railbelt—where natural gas remains the dominant generation source—have seen residential rates rise substantially, influenced by both commodity price shifts and infrastructure costs.

Several factors underpin KEA's long-term rate stability:

- Strategic Planning and Commitment: KEA formally committed to achieving over 95% renewable generation in 2007 and has made consistent, incremental progress toward that goal. This long-term orientation allowed the utility to align infrastructure investments with funding opportunities and operational capacity.
- Access to Public Funding: KEA's power system has benefited substantially from early public investment. The Terror Lake Hydroelectric Project was one of four major hydro assets developed under the State of Alaska's Four Dam Pool program, which involved an estimated capital investment of over $1.2 billion in today's dollars across all four projects. Although KEA and the other participating utilities have repaid a significant portion of this investment, there is no question that the state played a pivotal role in enabling the initial infrastructure. This model is consistent with other state-supported energy infrastructure efforts, such as the Bradley Lake Hydroelectric Project, for which the state covered approximately 50% of the cost through grants.
- Governance and Control: KEA's transition to full ownership of the Terror Lake hydro facility in 2009 highlights the strategic advantages of unified local control. KEA has stated that only after assuming full responsibility was it able to optimize operations and plan targeted improvements—such as the installation of a third turbine in 2014. This level of system-level coordination contrasts sharply with the Railbelt, where no single entity is responsible for optimizing the grid as a whole. Instead, fragmented ownership and decision-making across utilities make it difficult to pursue region-wide efficiencies or long-term investment strategies. The result is a system that often operates below its potential. In many respects, the Railbelt reflects an Alaskan version of the *Prisoner's Dilemma*: each utility acts rationally to serve its own interests, but the cumulative effect is a less efficient and more costly system for everyone.

In conclusion, the Kodiak KEA example highlights that stable, low-cost power is not solely a function of resource availability—it is equally dependent on strategic intent, aligned incentives, and the ability to make long-term infrastructure and operational decisions. For the Railbelt, where decarbonization goals are increasingly part of the planning landscape, KEA's experience may offer relevant lessons—not in replicating its specific mix of resources, but in the value of integrated planning, clear accountability, and long-term commitments to affordability and reliability.

Prepared by: Gwen Holdmann, Chief Scientist, and Laurent Nassif, Research Faculty — Alaska Center for Energy and Power (ACEP), University of Alaska Fairbanks

Insights for Alaska's Railbelt from Kaua'i Island Utility Cooperative

Overview

This report compares the residential electricity rate for Kaua'i Island Utility Cooperative (KIUC) with the average electricity rate across the state of Hawai'i. Over the past decade, KIUC has integrated renewable energy rapidly and at a low cost, coinciding with a long period of stable residential rates. Hawaiian Electric Industries (HEI)—serving O'ahu, Maui, and Hawai'i Island—has moved toward renewable integration more gradually. Factors such as aging infrastructure, transmission and distribution limitations, and constrained access to firm local energy resources have slowed progress and maintained reliance on imported fuels for power generation. Consequently, residential rates in HEI's service territory have shown greater year-to-year variability and a longer-term upward trajectory.

KIUC shares both similarities and differences with Alaska's Railbelt grid. It is Hawai'i's only cooperatively owned utility, in contrast to the investor-owned HEI. KIUC operates on a smaller scale with a primarily distribution-oriented network, serving about 39,978 customer meters (29,000 residential, 4,000 commercial, and about 130 large power accounts), compared with roughly 266,000 customer accounts across the Railbelt's five utilities.

The closest equivalent to KIUC on the Railbelt is the Homer Electric Association (HEA), which has nearly the same number of customer meters (about 38,000) and a similar peak load (80 MW for HEA versus 75 MW for KIUC). Both are member-owned cooperatives operating islanded grids and confronting similar challenges related to cost, reliability, and integration of local energy resources, though their geographic and energy generation contexts differ.

While the KIUC–HEI comparison provides insight into small-scale cooperative utilities, there is also value in examining the experience of HEI, particularly on O'ahu. With a peak load above 1,600 MW and over 300,000 meters on O'ahu alone, HEI's operations more closely mirror the scale and complexity of the Railbelt. Thus, HEI offers important lessons on integrating renewables into large islanded systems and navigating the trade-offs between grid reliability, cost containment, and emissions reductions. In particular, HEI's experience with utility-scale solar, battery storage, grid modernization, and meeting Renewable Portfolio Standards (RPS) provides insight into many of the challenges and decisions the Railbelt will face as it increases renewable penetration in its own isolated grid.

Background: Hawaiʻi Utility Landscape

The state government in Hawaiʻi plays an active role in shaping energy policy and utility oversight. Hawaiʻi attracted national attention in 2015 when it became the first U.S. state to adopt a 100% RPS, requiring all electricity from public utilities to come from renewable sources by 2045. This ambitious goal was motivated by Hawaiʻi's near-total reliance on imported fossil fuels, which historically drove some of the highest electric rates in the nation and exposed ratepayers to significant price volatility. Since 2015, Hawaiʻi's legislature has also adopted interim benchmarks and programs to support distributed energy resources (DER), community-based renewable energy, and grid modernization.

Hawaiʻi's electricity system is divided between two utility structures: KIUC and HEI. KIUC is a member-owned cooperative serving the island of Kauaʻi. It was formed in 2002 when Citizens Utilities sold its assets to the newly formed KIUC. This transition reflected a grassroots push for local ownership, improved reliability, and greater accountability to residents. The rest of the state—including Oʻahu, Maui, Hawaiʻi Island, Lānaʻi, and Molokaʻi—is served by HEI, an investor-owned utility that operates through three subsidiaries: Hawaiian Electric Company (HECO), Maui Electric Company (MECO), and Hawaiʻi Electric Light Company (HELCO).

Regulation in Hawaiʻi is provided by the Public Utilities Commission (PUC), which reviews utility resource plans, rate structures, power purchase agreements, and major capital investments. While Kauaʻi Island Utility Cooperative (KIUC) is subject to many of the same planning and reporting requirements as Hawaiian Electric Industries and its subsidiaries, it is not rate-regulated by the PUC in the same manner because of its cooperative structure[1]. Instead, KIUC's rates are approved through internal governance by its elected board of directors. This stands in contrast to Alaska's Railbelt, where electric cooperatives remain under the rate oversight of the Regulatory Commission of Alaska (RCA)[2].

KIUC Since 2002: Renewable Growth and Rate Stability

When KIUC was formed in 2002, it was almost entirely dependent on imported fossil fuels—primarily diesel—for electricity generation. Like the rest of Hawaiʻi at the time, Kauaʻi lacked access to locally sourced firm power and had no interconnections to other islands, leaving its energy system especially vulnerable to price fluctuations in the global oil market. This dependence contributed to some of the highest electricity rates in the nation and constrained the utility's ability to plan for long-term cost stability and emissions reductions. Having inherited this legacy system, KIUC began pursuing

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[1] In Alaska, electric cooperatives may be either rate-regulated or member-regulated. State law (Alaska Statute 42.05.711) allows cooperatives such as Copper Valley Electric Association (CVEA) and Alaska Village Electric Cooperative (AVEC) to opt out of Regulatory Commission of Alaska rate oversight if their members vote in favor. When this occurs, rates are set by the cooperative's elected board of directors rather than by the Regulatory Commission of Alaska.

[2] There have been instances where Railbelt utilities have attempted to deregulate. The most recent instance occurred in 2016, when Homer Electric Association held a deregulation (opt-out) election; members voted against it, and the cooperative remained under Regulatory Commission of Alaska oversight.

alternatives soon after its formation, with the expectation that greater local control and community ownership could support more aggressive strategies to reduce fuel dependence and stabilize rates.

In the two decades since its formation, KIUC has become a notable case study of locally driven renewable energy integration and energy rate trends. Figure 1 illustrates the increase in renewable energy generation as a share of total electricity production alongside residential electricity rates (not adjusted for inflation). The chart shows a correlation between high renewable energy penetration and stable—and in some years, reduced—residential rates, though other factors may also have contributed to this result.

According to KIUC's 2021 RPS filing and public statements by CEO David Bissell:

- KIUC achieved 69.5% renewable generation in 2021, more than double the state's RPS requirement of 30% and significantly ahead of Hawai'i's 2045 target.
- KIUC reported the highest reliability statistics in the state in 2021. Despite oil prices rising globally by nearly 75% between March 2021 and March 2022, KIUC member bills rose by only 5%, compared with 25–35% increases for customers elsewhere in the state. KIUC's leadership attributes this stability to fixed-price renewable contracts, which reduce exposure to fuel market volatility.
- According to the CEO, the cooperative's small size is a comparative advantage, which is unusual in an industry where economies of scale typically drive costs.
- KIUC's approach has "largely weaned [the utility] off oil," with this progress achieved within just 20 years of cooperative ownership.
- The West Kaua'i Energy Project (WKEP) is expected to bring renewable generation on the island to nearly 90% by the end of 2025.

While KIUC's progress has far exceeded the state's RPS mandate, this trajectory appears to have been motivated primarily by economic and operational considerations rather than regulatory compliance. In contrast to HEI, which appears to be pacing its renewable integration to align with mandated benchmarks, KIUC's leadership has emphasized the financial logic of renewables as a core driver. This distinction may help explain the cooperative's faster adoption and higher penetration of renewables.

By comparison, HEI has advanced more cautiously over the same period. Operating at a much larger scale and across multiple islands, HEI faces challenges related to aging infrastructure, transmission constraints, and the availability of firm local energy resources. Over the past decade, HEI's renewable energy generation increased from 11% to 32%, largely in step with the state's RPS benchmarks, rather than exceeding them (Figure 2).

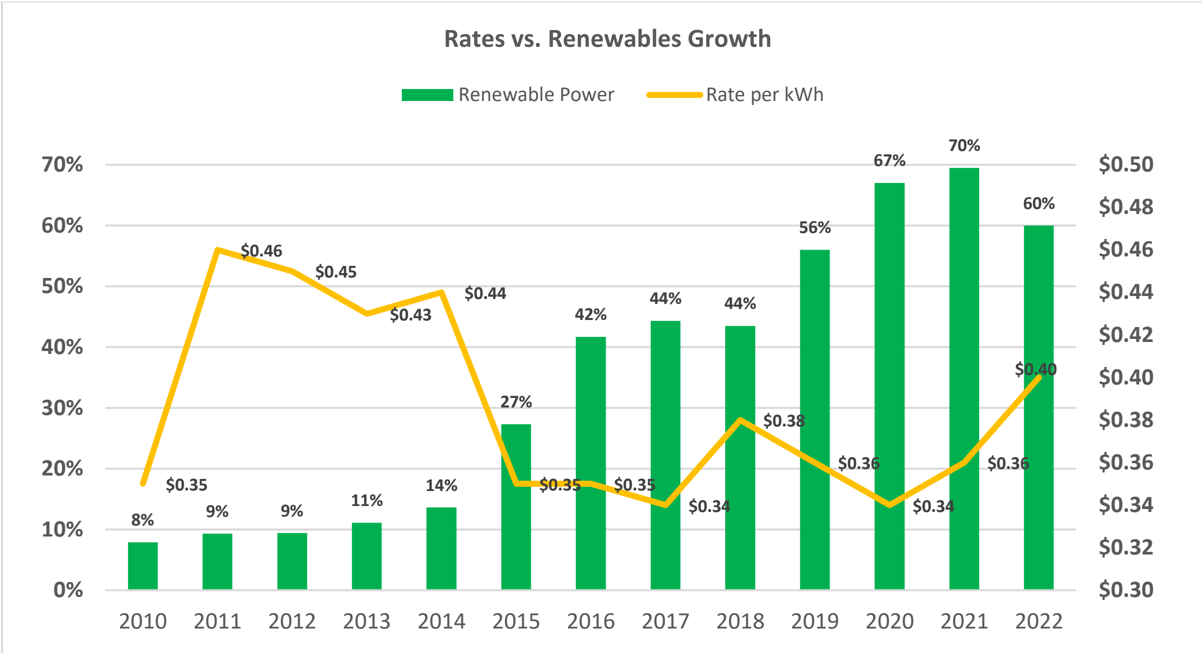

Figure 1. KIUC renewable energy integration and rate changes from 2010 to 2022. *Source: KIUC rate case filing as of June 2025.*

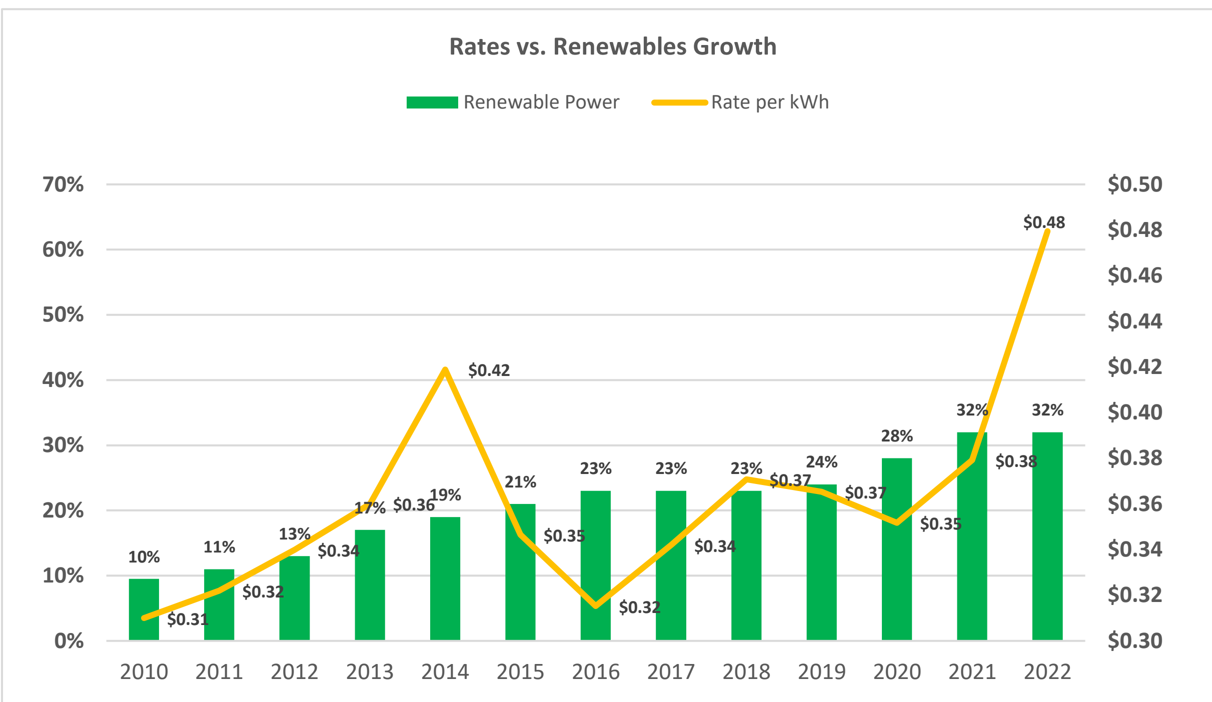

Figure 2. HECO renewable energy integration and rate changes from 2010 to 2022. *Source: DBET reports, HEI reports, and rate case filing as of June 2025.*

Technical Considerations of High Renewable Penetration for KIUC

KIUC's rapid transition to a high-renewables portfolio has not come without technical challenges. Integrating variable and firm energy generation resources—primarily solar photovoltaic (PV)—at penetration levels approaching 70% requires significant adjustments to system operations, grid stability practices, and resource planning. These challenges have also highlighted the growing importance of incorporating firm renewable energy sources such as biomass and long-duration energy storage to ensure reliability across different operating conditions. See Appendix 2 for a map of all projects constructed to date and a view of KIUC's renewable energy integration by type.

Inverter-Based Resources and Syncon for System Stability

A key characteristic of KIUC's renewables mix is the dominance of inverter-based resources (IBRs), especially solar PV paired with battery storage. Unlike synchronous generators, IBRs do not inherently contribute to system inertia or voltage and frequency regulation. As the proportion of IBRs increased, KIUC faced reliability issues during certain operating conditions, particularly during faults or periods with minimal spinning reserves. To address these challenges, KIUC deployed a synchronous condenser (Syncon) to provide system inertia and voltage stabilization, enabling fuel-free operation during parts of the day while maintaining grid reliability. Similar approaches have been implemented in rural Alaska, such as in St. Paul[3], to support high penetration levels of variable renewable energy while ensuring stable system performance.

The Role of Hydropower

Hydropower contributes 10–12% of KIUC's annual generation, playing an important role in balancing the variability from solar. KIUC's hydropower predominantly consists of run-of-river hydro systems, which provide limited dispatchability and firm capacity compared to large reservoir-based hydro systems. However, they still offer value in reducing fuel dependence and stabilizing output during key parts of the day, especially in conjunction with solar and battery resources.

Firm Renewable Resources: Mahipapa Biomass Facility

KIUC's renewable mix includes not only variable sources like solar and run-of-river hydro but also firm renewable generation. The Mahipapa biomass facility, operated in partnership with Pacific Current, contributes approximately 10% of Kaua'i's electricity needs using locally grown eucalyptus as fuel. As a dispatchable renewable resource, Mahipapa plays a key role in balancing grid demand and maintaining system reliability, particularly during periods of low solar output or high load. Its consistent output and local sourcing also increase the island's energy security and economic resilience.

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[3] On St. Paul Island, a synchronous condenser was deployed in 1999 at Tanadgusix Corporation's Power Operations & Support Site (POSS Camp), the airport and industrial complex. Installed as part of a high-penetration, no-storage wind–diesel hybrid system, the condenser provides voltage and frequency support, improves system stability, and enables increased utilization of wind generation.

Pumped Hydro and Long-Duration Storage Planning

KIUC proposed the West Kaua‘i Energy Project (WKEP), a hybrid solar, battery, and pumped hydro system intended to provide up to 12 hours of storage and meet roughly 25% of the island's electricity demand. This project was seen as a potential model for long-duration, firm renewable energy. However, due to legal challenges and rising development costs, the pumped hydro component was halted in 2023. KIUC is currently evaluating a scaled-back version of the project focused on solar and battery storage, while the future of the pumped hydro component remains uncertain. Despite the setback, the project reflects the utility's continued interest in long-duration solutions that complement high solar penetration.

Learning and Adaptation

KIUC's approach has evolved through iterative learning and close coordination between system operators, project developers, and technology vendors. Some early projects pushed system boundaries, leading to unexpected reliability issues that had to be addressed post-deployment. Rather than halting progress, these experiences helped KIUC refine its technical strategy, including:

- More advanced battery energy storage configurations
- Improved coordination between IBR controls and grid protection systems
- Long-term investments in grid-forming inverters and voltage support solutions.

While KIUC operates on a smaller, more self-contained scale than Alaska's Railbelt, its experience offers valuable lessons and demonstrates that technical hurdles can be overcome through focused investment, strong partnerships, and coordinated system-level planning. KIUC's experiences highlight the importance of integrating technologies appropriate for the local resources and geographical area. Pumped hydro and battery storage, for instance, appear to be prime technology candidates for integration.

Comparison of Electric Residential Rates and O‘ahu (HECO)

While electricity rates on Kaua‘i increased by 5–10% in 2021 and 2022, those changes were generally consistent with inflation, meaning that in real terms, rates remained stable. By contrast, utilities elsewhere in the state saw larger increases of 30–50% over the same period, outpacing the Consumer Price Index (CPI). This divergence reflects KIUC's greater use of long-term PPAs for renewable energy generation. These contracts are structured with fixed price components, reducing exposure to short-term fuel market volatility.

As shown in Figure 3, KIUC maintained lower average residential rates than the state's other utilities over 2021–2024 and extended a trend of relative rate stability even after its 2023 rate case.[4] Between

[4] Although KIUC is not rate-regulated by the Hawai‘i PUC in the same way as investor-owned utilities like HEI or Railbelt utilities in Alaska, it conducts "rate cases" through its own governance. These reviews are overseen and approved by KIUC's elected board of directors, with opportunities for member input. KIUC also submits financial reports to the PUC, but its rates are ultimately set internally rather than through commission approval.

2010 and 2024, Kauaʻi residents shifted from paying among the highest electricity rates in the state to the lowest (Figure 4).

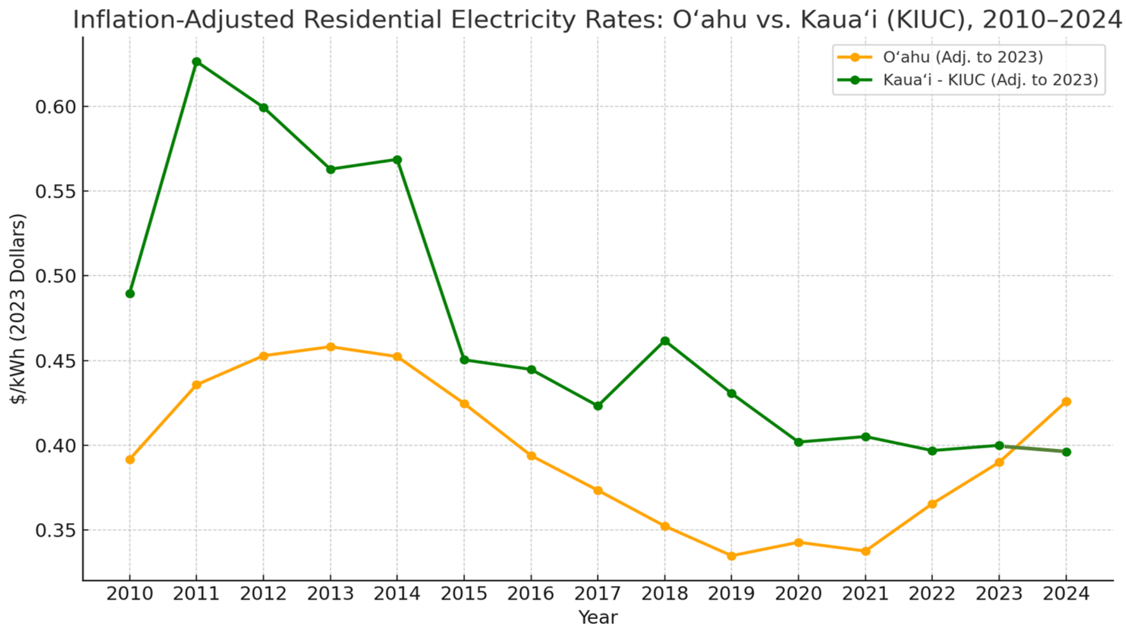

Figure 3. Inflation-adjusted residential electricity rates in Oʻahu and Kauaʻi over 2010–2024 (in 2023 dollars). This chart compares the rates for Oʻahu (Hawaiian Electric) and Kauaʻi (KIUC), adjusted using CPI data from the U.S. Bureau of Labor Statistics. KIUC's rates remain relatively stable over time, reflecting its shift to a diversified renewables portfolio with long-term fixed-price contracts. By contrast, Oʻahu's rates rose sharply in recent years, driven in part by continued reliance on imported fuels. *Sources: KIUC Annual Reports, Hawaiian Electric rate summaries, EIA, FRED, and BLS CPI-U.*

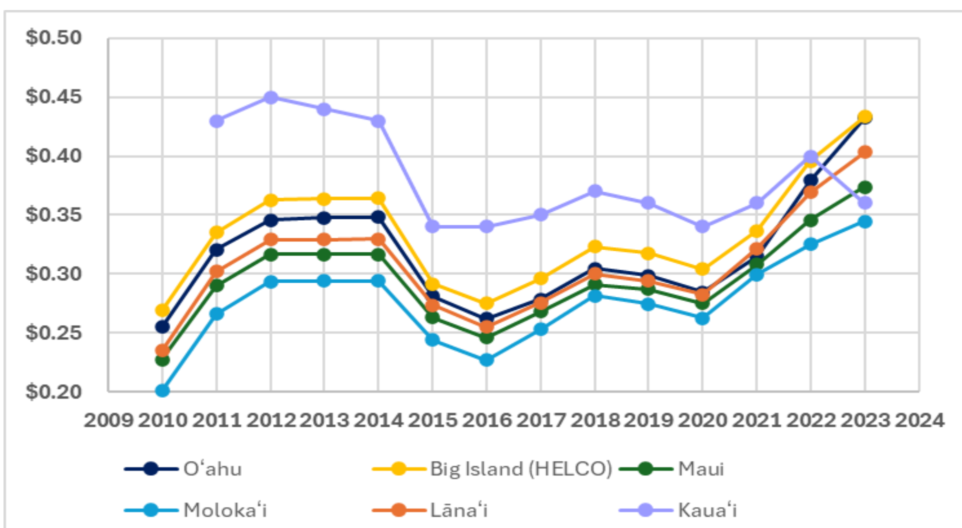

Figure 4. Average electricity rates for all major islands (2010–2023). The 2024 values were removed, as they reflect estimates or projections. *Sources: Kauaʻi data from DBEDT Facts & Figures (2011–2018) and the Hawaiʻi PUC FY2023 Annual Report (2021–2023 effective rates); additional data from KIUC,*

Civil Beat, Reddit, FindEnergy.com, and PUC filings; Oʻahu, Maui, Hawaiʻi Island, Molokaʻi, and Lānaʻi data from Hawaiian Electric (2010–2023).

Strategic and Structural Factors Behind KIUC's Rate Stability

Between 2010 and 2020, KIUC increased its renewable energy share from 7.9% to 69.5% of total power generation—an average of nearly six percentage points per year. Over the same period, residential electricity rates remained relatively stable and even declined during key integration years (2015 and 2016). This outcome is notable given the broader inflationary environment and the economic disruptions that raised costs for other utilities across the state. KIUC's investment in long-term, fixed-price renewable PPAs provided price certainty and reduced exposure to external shocks, including global fuel price volatility, supply chain disruptions, and geopolitical events.

While HEI has made steady progress, its efforts have mostly allowed it to keep pace with RPS mandates rather than significantly exceed them. This contrasts with KIUC's strategy, which appears to have been driven primarily by economic and operational considerations. The cooperative pursued renewable integration as a means to reduce exposure to fuel price volatility and stabilize long-term rates rather than in direct response to regulatory pressure. This distinction in motivation helps explain the faster pace and higher penetration of renewables in KIUC's system compared to HEI.

HEI also experienced periods of rate stability during its renewable integration period (2011–2021), with lower volatility and more gradual rate increases. However, with statewide renewable penetration still around 33%, HEI continues to rely significantly on imported fuels—particularly on Oʻahu—leaving it exposed to market fluctuations. In addition, HEI faces structural challenges, including limited storage capacity, transmission constraints, and a scarcity of firm local renewable resources. While the utility has initiated programs to address these barriers, progress has varied across islands and resource types. Without further expansion of firm renewable generation and storage, analysts and regulators have noted that HEI may struggle to meet future RPS targets.

KIUC's transformation into one of the most renewable-heavy and rate-stable utilities in the United States did not occur by chance. Several strategic factors enabled the cooperative to dramatically increase its renewable portfolio while keeping costs low and predictable for its members:

1. **Development of Local Generation and Reduced Dependence on Imported Fuels**
   KIUC invested in locally sourced renewable energy to reduce its reliance on imported fuels. A central element of this strategy was the use of long-term (typically 20 years) PPAs to increase price certainty, improve forecasting, and limit exposure to global fuel price volatility. KIUC's 2023 rate case—the first in over a decade—reflected, in part, the cost of maintaining its remaining fossil fuel assets.
2. **Infrastructure Transition and Optimization**
   KIUC gradually retired aging fossil fuel units and replaced them with renewable energy generation. This phased approach reduced stranded asset risk and helped avoid sudden rate changes. The cooperative also optimized the use of existing transmission, distribution, and

storage infrastructure to support renewable integration, reducing the need for large-scale system upgrades.

3. **Locally Tailored Renewable Integration Strategy**
   KIUC's integration plan was shaped by local system characteristics, resource availability, and infrastructure constraints. The cooperative aligned the pace of new projects with the retirement schedule of legacy assets and the operating profiles of renewable energy technologies. Kaua'i's limited local resources helped KIUC define clear renewable generation targets and an achievable roadmap. Appendices 1 and 2 summarize the integration pathways of KIUC and HECO.
4. **Use of State, Local, and Federal Support**
   KIUC leveraged funding and technical assistance from federal, state, and local programs to advance its projects. Partnerships with the County of Kaua'i, the State of Hawai'i, and various federal agencies helped lower financial and administrative barriers to renewable energy development.
5. **Member-Centered Long-Term Planning**
   As a cooperative, KIUC incorporated member input into its planning processes, with a strong emphasis on long-term cost stability. Investments were structured to limit exposure to fuel price volatility and reduce the risk of rate increases. Member surveys and stakeholder engagement informed key decisions. KIUC's small scale also allowed it to tailor its strategies to the specific characteristics and needs of its customer base.

Conclusion: Lessons for Alaska's Railbelt

KIUC's experience shows that stable residential electricity rates are not solely a function of resource availability, but also of effective governance, long-term planning, and strategies to reduce exposure to fuel price volatility. Its single governance structure and exemption from traditional rate regulation have allowed for more streamlined decision-making compared to Alaska's cooperative utilities. Over the past two decades, KIUC has shifted from near-total reliance on imported diesel to one of the highest shares of renewable energy generation in the United States, while maintaining comparatively stable residential rates in both nominal and real terms.

This KIUC case study highlights several relevant aspects for Alaska's Railbelt. While the Railbelt differs in geography, climate, and resource mix, it faces many of the same structural challenges: isolated grids, dependence on thermal generation, and aging infrastructure spread across a small customer base. KIUC's experience suggests that cooperatives can scale renewable energy integration effectively when local decision-making, long-term contracting, and resource planning are aligned. Leveraging existing infrastructure while phasing in renewables incrementally contributed to rate stability in Kaua'i and could inform coordinated investment strategies on the Railbelt.

It is important to recognize that not all aspects of KIUC's approach can be directly applied in Alaska. From a governance perspective, KIUC operates with a high degree of autonomy in part because it is physically isolated from other island grids, allowing it to chart its own course with limited external dependencies. By contrast, Railbelt utilities are also autonomous entities from a governance standpoint, but they are interconnected through shared infrastructure on the Railbelt grid. As a result, decisions made by one utility inevitably affect others. This interdependence has historically made collective planning difficult and has contributed to inefficiencies that have cost consumers significantly.

Kauaʻi's energy system—and particularly its transmission and distribution network—is relatively compact. Its strategy has been shaped by the island's substantial solar resources and land use constraints, factors that may not be directly applicable to the more geographically expansive and diverse Railbelt system. For example, the cost and legal challenges that ultimately halted KIUC's pumped hydro project may not pose the same barriers in Alaska, where land availability and local support for energy infrastructure can differ significantly. Conversely, Alaska's broader geographic scale and significantly more extensive and complex transmission network introduce technical and logistical challenges not present in Hawaiʻi. These differences underscore the importance of adapting—not copying—lessons from KIUC's experience.

HEI, particularly on Oʻahu, provides complementary insights. Despite progress in renewable energy deployment, HEI has faced difficulties stabilizing costs due to continued reliance on imported fuels, transmission and storage limitations, and a more complex regulatory and investment environment. These challenges underscore the importance of a supportive policy and regulatory framework—one that enables timely development of both firm and variable renewable resources, provides predictable permitting, and aligns incentives across utilities, regulators, and communities. They also highlight that strategies for integrating renewables which work effectively on smaller grids—whether at KIUC or in hub communities in rural Alaska—are far more difficult to replicate at larger scales.

Taken together, Hawaiʻi's utilities offer useful lessons for Alaska. KIUC illustrates how cooperative governance and economic drivers can accelerate renewable energy adoption while maintaining energy affordability. HEI highlights the challenges that larger, more complex systems face in balancing costs, reliability, and emissions goals. These experiences reinforce that achieving stable, low-cost electricity depends not only on physical resources but also on governance, planning, and a sustained commitment to reducing dependence on volatile fuel markets. At the same time, Alaska's Railbelt faces an added layer of complexity: unlike Hawaiʻi's fully vertically integrated, monopoly utility structures, its multiple independent cooperatives share a common transmission system. This creates both technical interdependencies and governance tensions, as each utility prioritizes its own interests within a system where collective outcomes depend on coordination.

Appendix 1: HECO Renewable Portfolio Standard (RPS) Progress (2011–2022)

HECO's renewable portfolio grew steadily from 2011 to 2016 (11% to 23%), driven mainly by rooftop solar, wind, and early utility-scale projects supported by state policies such as net metering and feed-in tariffs. Progress then stalled at 23–24% in 2019, in part due to the 2018 volcanic eruption that shut down geothermal production, which underscores the system's reliance on firm renewable generation. Growth resumed in 2020 with the restart of geothermal production and continued solar additions, lifting renewable generation to about 32% by 2021, but it has since plateaued. Key constraints include rising energy demand, transmission and distribution bottlenecks, limited energy storage, and a lack of new firm renewable resources. Without addressing these structural barriers, further progress toward Hawai'i's RPS goals—and the cost stability that comes with reducing fossil fuel dependence—will remain difficult.

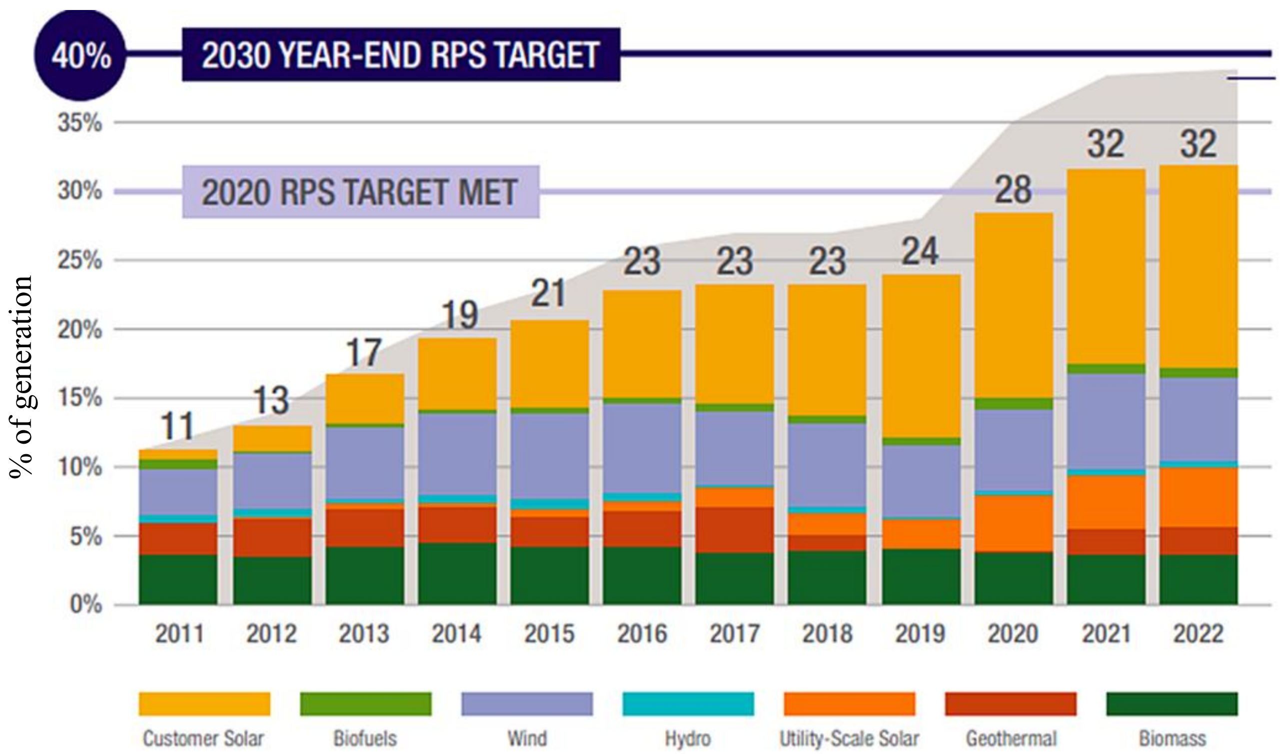

Figure 5. HECO's renewable energy portfolio relative to the RPS target from 2011 to 2022. *Source: Hawaiian Electric's annual RPS Status Reports filed with the Hawai'i Public Utilities Commission. These reports are public documents available on the Hawaiian Electric website and via the Hawai'i PUC docket system.*

Appendix 2: Detailed Renewable Integration for KIUC

KIUC, whose total electricity demand is a fraction of Hawaiian Electric's and whose cooperative governance structure provides comparatively greater flexibility in decision-making, pursued a renewable energy integration pathway shaped by local system characteristics. The cooperative's strategy emphasized (1) displacing imported fuels through locally produced generation, (2) pairing variable resources with storage capacity to maintain system reliability, (3) co-locating generation with demand to avoid transmission bottlenecks, (4) maximizing the use of locally available renewable resources such as hydroelectric, biomass, and solar, and (5) piloting and adopting new technologies, including high-efficiency turbine designs. Taken together, these priorities allowed KIUC to steadily increase renewable penetration while reducing exposure to external fuel price volatility and minimizing the need for large-scale transmission expansion.

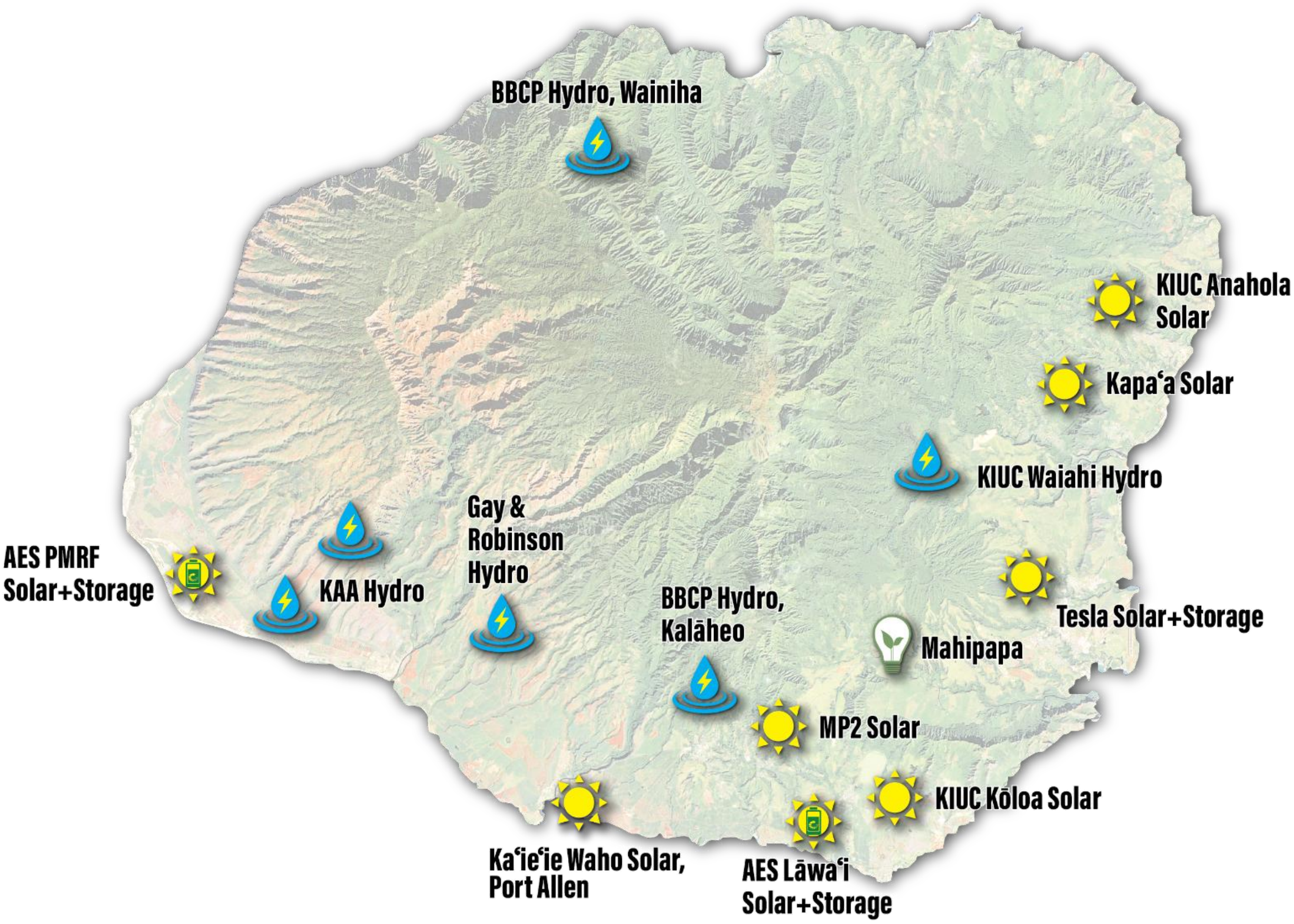

Figure 6. Map of KIUC's major renewable energy projects, including hydroelectric plants, utility-scale solar, and solar-plus-storage facilities. *Source: KIUC, Annual Renewable Energy Report (various years).*

As shown in Figure 7, KIUC's initial 9% renewable integration (2011) mostly consisted of hydroelectric. While hydroelectric production was higher in 2021–2023, it remained a small portion of the total renewable energy. Biomass use increased significantly in 2016 but then remained relatively constant until 2023. The majority of KIUC's renewable energy generation in recent years was from residential solar and utility-scale solar. The latter was often combined with energy storage, allowing its use for meeting the base load and not just variable loads. KIUC met the 30% RPS target for 2020 years ahead of schedule and has already met the 40% RPS target for 2030.

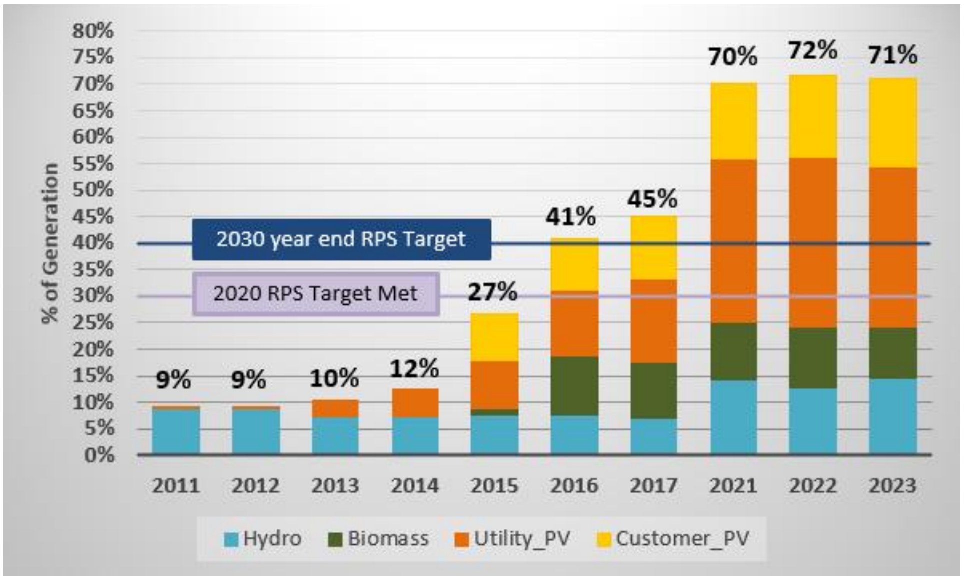

Figure 7. Breakdown of KIUC's renewable energy integration by type from 2011 to 2023. *Source: KIUC, Annual Renewable Energy Report (various years).*

HB 307 Requirements and Railbelt Transmission Organization Update:

Follow-up on HB 307, including the creation of the RTO, its open-access transmission tariff (OATT) application, and the RCA opening of docket U-25-028

Jennifer Pemberton and Gwen Holdmann
Alaska Center for Energy and Power, UAF
December 23, 2025

Contents

Overview

This document provides an update to the Alaska State Legislature on progress toward meeting the requirements established under House Bill (HB) 307, enacted as Chapter 24, SLA 2024. The bill directed the Alaska Energy Authority (AEA) and Railbelt utilities to form a Railbelt Transmission Organization (RTO) by January 1, 2025, modeled after the governance structure of the Bradley Lake Hydroelectric Project. It further required the new RTO to apply to the Regulatory Commission of Alaska (RCA) for certification and to develop a nondiscriminatory open-access transmission tariff (OATT) governing use of the Railbelt backbone transmission system (BTS).

The intent of this report is to provide the Legislature with a clear summary of implementation progress, highlight areas of regulatory focus and contention, and place current RCA proceedings in the context of the directives and policy objectives set forth in HB 307. It covers actions taken between September 2024 and December 2025, including formation of the RTO, submission and approval of its certificate application, and subsequent filings with the RCA related to the OATT. It also outlines major issues now under consideration in RCA docket U-25-028, which was opened to review the OATT proposal—most notably, the proposed "regional allocator" for cost distribution and the treatment of "grandfathered agreements" that preserve existing wheeling arrangements.

RTO implementation from September 2024 to October 2025

The RTO started meeting in September 2024. The charter agreement and bylaws were passed at the *December 16, 2024*, meeting – ahead of the January 1 deadline. On December 20, 2024, the RTO complied with the Legislature's directives to submit an application to the RCA for a certificate. That certificate was granted on May 6, 2025, when the RCA issued Order No. U-24-042(7), authorizing the RTO to provide the services required by AS 44.83.700 – AS 44.83.720.

On or before July 1, 2025, the RTO was also responsible for establishing and administering an OATT, consistent with FERC standards that (1) provides for the recovery of Railbelt backbone transmission costs and related ancillary services; and, (2) replaces wholesale charges assessed by unit by each utility in the Railbelt charges with a new mechanism that fairly recovers and equitably allocates the costs of operating the backbone transmission system.

The RTO *submitted its OATT* application with the RCA on July 1, 2025. On July 15, the Alaska Office of the Attorney General Regulatory Affairs & Public Advocacy (AG RAPA) Section *filed a list of twelve areas of concern* regarding the application. Three other groups had similar concerns, leading the *RCA to suspend the order on August 14*. At a prehearing conference in August the RTO members and the petitioners *agreed to extend the RCA suspension until June 4, 2026*, which would serve as the deadline for a final decision on the OATT application. The RCA opened docket *U-25-028* to address the OATT and issued Order #1 in that docket on August 14, 2025. Order #1 provides a summary of the concerns raised during initial public comment and poses 15 pertinent questions. The RTO was required to answer and other parties to the docket[1] were invited (but not required) to answer. Testimony responding to the questions and requirements of Order #1 was submitted on October 22, 2025.

Major issues being addressed by RCA in docket U-25-028

This section is intended to complement RCA *Order #1* in docket U-25-028. This Order provides a summary of the requirements imposed by HB 307, the initial OATT proposal, and the issues being considered.

Issue 1. The Regional Allocator

The RTO in its July OATT filing proposed the use of a "regional allocator" to include only **some fraction** of a transmission owner's costs (known as the Annual Transmission Revenue Requirement or ATRR) in the cost pool for regional (i.e., Railbelt-wide) allocation. The stated rationale in the filing for including

[1] Other parties include each of the Railbelt utilities, Bradley Project Management Committee, Railbelt Reliability Council, Alaska Intertie Management Committee, Renewable Energy Alaska Project (REAP), Alaska Public Interest Research Group (AKPIRG), Alaska Wind Holdings, and AG RAPA. A complete and up to date list can be found on the RCA web site

only some portion of the **cost** of transmission as regional is that only some portion of the **benefits** are regional:

> "Regional transmission organizations in the Lower 48 that were starting up often roughly assigned costs based on the perceived benefits received, and the RTO recognized it could make sense to consider these circumstances in allocating the ATRR."[2]

Having proposed the regional allocator approach, the RTO did not propose any values for this critical parameter. They stated:

> "With the short amount of time available to compose its OATT, the RTO did not have the time to conduct the in-depth studies needed to determine an appropriate value for a regional/local benefit allocator for the Railbelt."[3]

Thus, the Regional Allocator remains as a TBD component of the OATT. Without a value or values for this parameter, it is not possible to implement the OATT.

Concerns raised by others

- The RCA asked for justification of the Regional Allocator concept and whether it might "introduce a layer of complexity that could be avoided."[4] It also asked why the RTO is apparently proposing only one number, rather than a separate allocator for each utility.
- At least two parties argue that the use of a Regional Allocator less than 100% does not follow the law as enacted by HB 307 and would reflect neither Railbelt realities nor Lower 48 precedent. Willis Geffert, in his testimony on behalf of the City of Seward, summarizes this argument:

  > "Based on the evidence I have reviewed and my experience working as a regulatory economist in the power sector, I suggest the Commission determine that 100% regional allocation of BTS costs is appropriate (100% rolled-in treatment), considering the applicable legal and regulatory framework and relevant economic-regulatory principles and precedents. I base this conclusion on several factors: 1) a plain language reading of HB307 and the RTO's BTS Policy Document, Policy 25-01 ("BTS Policy"), both of which seem to support socialized or rolled-in treatment of BTS costs across the Railbelt; 2) the relative small size of the Railbelt and the backbone nature of the BTS; 3) precedent from the Lower 48 for broad regional allocation of transmission costs."[5]

  In a similar vein, Antony Scott, representing Renewable Energy Alaska Project, states that HB 307 is highly prescriptive as to the allocation of costs (per AS 44.83.710(c)(1)) and that reliance on or consistency with FERC standards is only required for the purpose of removing impediments to competition (per AS 44.83.710(b)). With respect to the Regional Allocator, Scott states:

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[2] RTO Tariff filing TA1-8001, pp 8-9
[3] RTO Tariff filing TA1-8001, p 9
[4] Order #1, Question 3 at p 8.
[5] Responsive testimony of Willis Geffert on Behalf of Seward Electric System, October 22, 2025 at p 6. The BTS Policy 25-01 to which Geffert refers can be found with the testimony of John Sinclair filed Sep 12, 2025, at exhibit JDS-2.

Alaska Center for Energy and Power • University of Alaska Fairbanks • 1764 Tanana Loop – ELIF Suite 404
P.O. Box 755910 • Fairbanks, Alaska 99775-5910 • Tel: (907) 474-5402 • Fax: (907) 474-5475

> "[T]he provisions of HB 307 are clear: costs must be allocated on the basis of load ratio share, coincident peak, or a combination of both. No provision is made for additional methods. By specifying acceptable methods, the legislature excluded those not listed."[6]

- Several parties are concerned about timing and ask that the RCA set deadlines for the determination of the Regional Allocator(s), and/or require the use of inception allocators so that the OATT can be implemented before all of the studies are completed.
- Geffert argues that if the RCA decides to allow the use of Regional Allocator(s), their values should be determined using production cost modeling and not by using power flow modeling and associated engineering techniques. His idea is to:

> "consider the benefit of having a backbone transmission system in the Railbelt. I suggest the following conceptual set up: compare the Railbelt as it is today with a hypothetical Railbelt without any interconnections between the Railbelt utilities, resulting in five isolated utilities."[7]

ACEP Comments on Issue 1

The concept of the Regional Allocator and the underlying idea that some of the BTS should be declared "local" and categorically excluded from the HB 307 cost allocation scheme was never mentioned during the legislative process in spring 2024. To our knowledge, it first appeared in the RTO's tariff filing. Quantitatively, the value or values of the Regional Allocator would or will have a **significant** effect on how BTS transmission costs are allocated. Based on its Order #1, the RCA appears to be quite concerned about whether this Regional Allocator is appropriate. This concern is merited.

Current Status of Issue 1 in Docket U-25-028

On November 14, 2025, the RCA received documentation related to *Order #1*, requesting briefings related to 15 questions to the RTO, AG RAPA, and any interested parties.[8]

In the order the RCA specifically asked for more information about the timing and implementation of the Regional Allocator mentioned in the RTO's initial OATT filing. In its *response* the RTO asked for more time to study the impact of what it refers to as a "Benefit Allocator," the purpose of which would be to determine the portion of transmission revenue requirement that provides regional benefit to ensure that the expense corresponds to the benefit received. It argues that the allocator would be "consistent with HB307's directive to implement a mechanism that 'fairly recovers and equitably allocates the costs of operating the' backbone transmission system." It goes on to say,

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[6] Prefiled Responsive Testimony Of Antony Scott On Behalf of Renewable Energy Alaska Project, October 22, 2025 at p 11-12.
[7] Geffert prefiled testimony, October 22, 2025, at p 34.
[8] RCA received responses from RTO, AG RAPA, Alaska Intertie Management Committee (IMC), Bradley Lake Project Management Committee (BPMC), AEA, REAP, Railbelt utilities, Railbelt Reliability Council (RRC), Aurora Energy, and AKPIRG

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"However, until the necessary studies are determined and conducted, the RTO will not know for certain whether the Benefit Allocator is needed."[9]

The RTO gives an estimated, speculative completion date of April 22, 2027 for its study and states furthermore:

> "With this in mind, and understanding the development of a methodology and execution of studies necessary for a Benefit Allocator is complex and the full scope is not yet known, the RTO's best estimate is that it would submit the comprehensive methodology and associated studies related to any Benefit Allocator(s) with its initial cost of service filing on October 1, 2027."[10]

In its required briefing AG RAPA reiterated its opposition to the regional benefit allocator, calling it "contrary to the principle that the BTS is a single, integrated machine and that the entire BTS benefits from the inclusion of each integrated asset included in the BTS." The AG agrees with the RCA that the idea "injects unneeded complexity" and argues against designing studies for the allocator that will "most likely be subject to lengthy challenges," and "would likely need to be repeated each time new transmission assets are added to the BTS."[11]

REAP and *Aurora Energy* argue in their responses that a regional allocator is not allowable under HB 307 and AS 44.83.710(c)(1), as does *AKPIRG*, though the latter goes on to say that "if the Commission does determine that a regional allocator is allowed under HB 307 and is appropriate, we urge several steps to speed implementation of the OATT and to ensure that the allocator accounts for the full range of benefits Network Customers receive from their connection to the BTS."[12] Those suggestions include the use of a provisional allocator during the study period if the RCA allows for the study of the beneficial allocator.

The City of Seward utility (SES) provided a lengthy response to the allocator questions, stating that it has had time to conduct further research on the issue since the initial discussions on the issue leading up to the initial OATT filing deadline. It calls the regional allocator in the application a "placeholder" while the RCA decides if any study design is warranted to align the final concept with HB 307. It's worth reading the entirety of its brief, but it concludes with this:

> "A regional/local allocator is necessary to the extent that it would provide a baseline study to weigh future network upgrades, accurately defines benefits of interconnection, and builds consensus amongst the potential Network Customers and their customers that the benefits are

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[9] Railbelt Transmission Organization's Brief on Issuing Questions, As Modified by Order No. 7, Received by the RCA on Nov. 14, 2025, Answer to Question 3, p. 7

[10] Railbelt Transmission Organization's Brief on Issuing Questions, As Modified by Order No. 7, Received by the RCA on Nov. 14, 2025, Answer to Question 2, p. 6

[11] Office of the Attorney General's Response to Order U-25-028(1), Received by the RCA on Nov. 14, 2025, Answer to Question 4, p. 8

[12] Alaska Public Interest Research Group's Brief in Response to Questions Issued in Order U-25-028(1), Received by the RCA on Nov. 14, 2025, Answer to Question 3, p. 3

roughly commensurate with costs. Studies are necessary to quantify the benefits derived from interconnection with increased accuracy. However, the regional/local allocator and studies are not strictly necessary from a technical or legal standpoint and introduce increased complexity to the NOATT and overall process. The RCA's question strikes at the heart of this issue: balancing accuracy and complexity with the language of HB307 and FERC precedent."[13]

Members of the RTO filed their responsive testimony on December 19, 2025, furthering their argument in favor of a Benefit Allocator and the need for a study to determine its value. They also contend that HB 307 does not preclude the RTO's concept of a Benefit Allocator by their interpretation.

In *his testimony*, GVEA's Daniel Heckman argues that a strict interpretation of AS 44.83.710(c), such as that of Anthony Scott from REAP and presumably the RCA, ignores other provisions of HB307. He says:

> "HB307 also states that 'the [RTO] is created for the purposes of establishing an [OATT] that (1) provides for recovery of transmission costs and related ancillary services; and (2) replaces wholesale charges assessed by unit by each utility in the Railbelt with a new mechanism that fairly recovers and equitably allocates the costs of operating the backbone transmission system.' Dr. Scott believes that the Alaska Legislature, by indicating in AS 44.83.710(c) that allocation of 'costs through certificated load serving entities' must be done on the basis of load ratio share, coincident peak, or a combination of both, excluded all other types of allocation in other parts of the revenue mechanism. There is no legislative history to support his claim that the Alaska Legislature actively excluded other cost allocation methods in its consideration of HB307."[14]

Carl Monroe's testimony additionally addresses Anthony Scott's argument against the RTO adopting FERC's standards, which he says are limited and do not address how costs should be pooled or allocated. When asked by RCA if he agrees with Scott's claims about the FERC standards, Monroe replies:

"I do not. The RTO used the principles and language from FERC Order 888 and subsequent rulings as an efficient and effective way to meet the HB307 requirements, including that the OATT be 'consistent with' FERC standards 'to remove impediments to competition in the wholesale bulk power marketplace.'"[15]

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[13] Seward Electric Systems Response to Issuing Questions, Received by the RCA on Nov. 14, 2025, Answer to Question 2, p. 3

[14] Prefiled Reply Testimony of Daniel A. Heckman on Behalf of the Railbelt Transmission Organization, Received by the RCA on Dec. 19, 2025, Answer to Question 7, p. 4

[15] Prefiled Reply Testimony of Carl A. Monroe on Behalf of the Railbelt Transmission Organization, Received by the RCA on Dec. 19, 2025, Answer to Question 9, p. 4

Issue 2. Treatment of "Grandfathered Agreements" that maintain wheeling

The RTO in its July OATT tariff filing identified 11 specific agreements,[16] which it labeled as "legacy agreements," and in its filing stated that "the RTO, like many regional transmission organizations in the Lower 48 when they were first established, opted to grandfather pre-existing agreements."[17] These 11 agreements then began to be labeled collectively as "the Grandfathered Agreements" (sometimes with capital letters) by various parties and by the RCA itself.

HB 307 did not use this term, nor did HB 307 use the term "legacy agreements."

The RTO has proposed a "hands-off" treatment of any money flowing between transactors pursuant to these agreements. The RTO acknowledges that "[while] grandfathering these agreements does not immediately result in the elimination of all wheeling in the Railbelt, the RTO recognizes that it took many years for the lower 48 markets to address legacy agreements – and to date less than a year has passed since the Governor signed HB307."[18]

The apparent justification for exempting wheeling transactions under these agreements is found in AS 44.83.710(c)(2)D), which requires that:

> "The nondiscriminatory open access transmission tariff must, as approved by the commission,
>
> (2) account for
>
> > (D) costs to own and operate the backbone transmission system, as established by the commission or by contract, including transmission costs associated with the Bradley Lake hydroelectric project."

Concerns raised by others

- AG RAPA noted that four of the 11 Agreements appear to have no relation to transmission rights.[19]
- Alaska Wind Holdings LLC is concerned that the Agreements perpetuate wheeling and undermine HB 307's purpose "to remove impediments to competition in the wholesale bulk power marketplace in the state:"[20]

> "Many of the Railbelt's most critical segments – such as the Alaska Intertie and Bradley Lake transmission assets – are subject to legacy agreements. These segments are clearly part of the BTS and were intended by HB307 to be integrated under the unified RTO structure and subject to the new cost allocation methodology. Allowing separate, transactional charges risks

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[16] According to the RTO's tariff filing TA1-8001 at page 8 (footnote 28), "See Attachment J of the OATT, listing the 11 legacy agreements that the RTO grandfathered. The bulk of these agreements relate to the Bradley Lake Hydroelectric Project, both of which are exempt from RCA regulation pursuant to AS 42.05.431(c) and AS 44.83.090(b). It may also be argued that the IMC agreement retains its exemption from RCA regulation pursuant to AS 44.83.090(b), even after HB307." The term "IMC agreement" refers to the Second Amended and Restated Alaska Intertie Agreement - March 11, 2014.

[17] Tariff Advice letter from RTO, TA1-8001, page 8.

[18] Tariff Advice letter from RTO, TA1-8001, page 8.

[19] AG RAPA Public Comments, July 15, 2025, p. 8.

[20] Codified as AS 44.83.710(b).

undermining the purposes of the OATT and limits its effectiveness in removing barriers HB307 seeks to address."[21]

To address the problem, Alaska Wind Holdings proposed a Legacy Wheeling Cost Recovery Adjustment (LWCRA):

"Under this mechanism, Network Customers would annually certify payments made under grandfathered agreements. These costs would then be pooled with BTS costs and allocated through the proposed coincident peak methodology."[22]

- AG RAPA also noted that the substantial payments to AEA for use of the Alaska Intertie fall under one of the Agreements and are **not** proposed to be included in the BTS cost pool. RAPA proposed a similar mechanism to the LWCRA: Payments to AEA for AK Intertie use can continue to be made under current procedures, but should then be included in the BTS cost pool.[23]
- AKPIRG asked the RCA to "address the Grandfathered Agreements in TA1-8001 and set deadlines for [their] termination."[24]

ACEP Comments on Issue 2

What has been called "Grandfathered Agreements" were not discussed in any meaningful detail during the HB 307 legislative process. Thus, there appears to be no statutory guidance regarding whether, how, and/or by when these agreements could or should be wound down. The workaround proposals[25] for what might be termed a "save the receipts" approach that would transfer grandfathered wheeling payments into the BTS cost pool for region-wide allocation have considerable merit.

The RCA is rightly concerned about the Agreements and whether they will or should perpetuate wheeling. Their final question (Question 15) in Order #1 is somewhat lengthy, but it highlights a central tension running through the docket. That tension is between two views of the Railbelt BTS. Under the first view, the Railbelt BTS is a collection of assets owned by different entities and governed in actual use by a large number of separate agreements and practices. Under the second view, the Railbelt BTS is a single regional machine that greatly benefits the entire region when compared to the alternative of not having it.

As the RCA states in Question 15, the RTO wants to exclude wheeling under the Grandfathered Agreements because "if they were to instead allocate the costs of the grandfathered agreements to all Network Customers it 'would result in some of those costs being borne in part by entities that are not parties to a particular agreement and thus did not cause those costs to be incurred.' "[26] This desire by

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[21] Alaska Wind Holdings LLC Public Comments, July 16 2025, p. 2.
[22] Alaska Wind Holdings LLC Public Comments, July 16, 2025, p. 3.
[23] RAPA Prefiled Testimony of Kevin S. Aufderheide, October 22, 2025, p. 17.
[24] RCA Letter Order #1 in U-25-028, p. 6. The referenced AKPIRG Public Comments are dated July 16, 2025.
[25] Alaska Wind proposed a general mechanism dubbed the "Legacy Wheeling Cost Recovery Aadjustment". RAPA proposed essentially the same mechanism for the payments to AEA for use of the Alaska Intertie. The Intertie payments, which are heavily oriented toward per-kWh wheeling charges, are the subject of one specific Grandfathered Agreement on the RTO's list of 11 agreements.
[26] RCA Letter Order #1, Question 15, at p 10. The single quotes contain language from the RTO's tariff filing at p. 8.

Alaska Center for Energy and Power • University of Alaska Fairbanks • 1764 Tanana Loop – ELIF Suite 404
P.O. Box 755910 • Fairbanks, Alaska 99775-5910 • Tel: (907) 474-5402 • Fax: (907) 474-5475

the RTO to apply the "cost-causer = cost-payer" criterion at a granular level seems to reflect the first view from above – that the BTS is a collection of assets and agreements, so fairness requires attention to the details of how each part of the system is being used and paid for. However, the RCA also asks in Question 15 whether the RTO could "[address] these legacy agreement costs in a way which would actually eliminate the wheeling impacts of them by allocating costs/revenues among all Network Customers?"[27] This part of the question seems to reflect the second view – that the Railbelt BTS is one regional machine with widespread benefits meriting widespread allocation of its costs.

Current Status of Issue 2 in Docket U-25-028

Order #7 required the RTO to file verified copies of its proposed grandfathered agreements and the AEA to file copies of certain bond covenants, as well as asking supplemental questions to Order #1 related to these required documents.[28] The RCA asserts that these requisitions and questions are "to inform our investigation into the term[s] of any exemption that might be granted for the proposed grandfathered agreements."

Order #1 asked several questions related to the grandfathered or legacy agreements that maintain wheeling in the BTS. In addition, the RCA in Order #7 asked for copies of all grandfathered agreements and verification that the versions provided are the most current. This is because the RTO indicated that some of these agreements are exempt by Article I, Section 15, of the Alaska Constitution, which prohibits state laws from "impairing the obligation of contracts." In order to evaluate this exemption under the constitution, the RCA asked to see the agreements to better understand "the scope of revision" required to bring them into compliance with the application.

Additionally, the RTO indicated in its application that it believes some of its agreements are exempt from RCA regulation via *AS 42.05.431(c)(1)*, which exempted Bradley Lake in the 1980s until "all long-term debt incurred for the project is retired." Therefore, the RCA required the RTO and invited the other parties to file briefs addressing whether that exemption is still relevant.

In its response, the *RTO* deferred to the briefings of the *BPMC* and the *IMC* because it is not as an entity a part of any of the grandfathered agreements in question. It does, however, argue that grandfathering pre-existing agreements *is* consistent with HB 307 by its reading that the Legislature had modeled it after FERC Order 888, a rule designed to "remove impediments to competition in the wholesale bulk power marketplace." By its logic, if FERC allows for grandfathering pre-existing agreements and it shares the same goal as HB 307, then the Alaska law should also allow for these grandfathered agreements.[29]

AG RAPA addressed the constitutionality of the grandfathered agreements in its response to Order #7, establishing that the RTO does not have the authority to require modifications to those

[27] RCA Letter Order #1, Question 15, at p 11. The bracketed word "address" replaces "addressing" in the text of the Order.
[28] RCA received responses from RTO, AG RAPA, IMC, BPMC, REAP, AEA, MEA, HEA, SES.
[29] Railbelt Transmission Organization's Brief on Issuing Questions, As Modified by Order No. 7, Received by the RCA on Nov. 14, 2025, Answer to Question 15, p. 28

agreements, that there are four agreements where AEA is not a party to contract but that the RCA has jurisdiction over them and the power to modify those contracts, and making a case that the long-term debts for the Bradley Lake project are indeed retired. The AG indicates that further detailed analysis is required for each of the grandfathered agreements and offers three options for proceeding:

> "Option one: finalize the non-discriminatory open access transmission tariff and the revenue mechanism for the BTS so that any immediate benefits can be realized. The Commission could allow an "inception" approval for grandfathering the agreements but defer the decision to permanently grandfather the agreements and address the agreements in separate future dockets.
>
> Option two: handle resolution of the issue in the following steps: (1) invite briefing on Commission jurisdiction over each grandfathered contract; (2) after briefing, the Commission determines its jurisdiction on each grandfathered contract; (3) invite briefing on whether HB307 substantially impairs the contract and if so whether the impairment is permissible as a legitimate exercise of the state's sovereign powers; (4) issue a final decision on the non-discriminatory open access transmission tariff, the revenue mechanism, and the grandfathered contracts.
>
> Option three: finalize the non-discriminatory open access transmission tariff and the revenue mechanism for the BTS so that any immediate benefits can be realized. Order the parties to the grandfathered contracts to develop a plan for the contracts to become compliant with the non-discriminatory open access transmission tariff."[30]

In its brief, BPMC refers to *Regulatory Comm'n of Alaska v. Matanuska Elec. Association, Inc., 436 P.3d 1015 (Alaska 2019),* or *RCA v. MEA,* arguing that the matters at issue in that case are identical to what's being questioned by the RCA in the order. As far as it is concerned, the idea of the Bradley Lake agreements being exempt from RCA jurisdiction is an open and shut case.

The *AEA* also uses its brief to establish its statutory exemption from RCA oversight. Of course, HB 307 did modify this exemption to some extent so that the RCA could have oversight of the RTO, which is a division of the AEA.

The *IMC* is not party to the Bradley Agreements, but it, too, uses its brief to declare its exemption from RCA jurisdiction. The IMC is a state asset, owned by the AEA and paid for by the state legislature. The IMC argues that "because AEA is not a utility, the tariff does not apply to it and its

[30] Office of the Attorney General's Responses to Order U-25-028(7), Received by the RCA on Nov. 14, 2025, pg. 13

interests in the Intertie leaving the exemption from RCA regulation intact."[31] It also brings up the Constitutional argument brought up by the RTO and invokes the FERC precedent, saying:

> "In administering Order 888 FERC took great care to allow grandfathered agreements to reach their respective end dates. Because the Intertie is exempt from regulation by the RCA, and the AIA is entitled to grandfathered rights, the RCA, like the FERC before it, must protect the IMC members' rights in the AIA and associated agreements."

The IMC is at the center of the intent of HB 307 to free up the transmission system from wheeling charges, but it seems to be doubling down on its exemption from participating in the protections the legislation intended to provide. IMC ends its response with:

> "As is argued in the brief filed by the IMC, it also appears that HB 307 works to impair IMC members' contractual rights and may also work as a taking of member interests in the AIA and associated agreements, in violation of constitutional protections."[32]

The problem with this argument is that transmission utilization changes over time. The utilization of the intertie or the entirety of the BTS today does not look like what the utilization of the future will look like. With new generation, transmission flows can, and likely will, change dramatically – a point made in the *E3 Alaska Railbelt Wind Integration Study* that was analyzed for the committee as part of the Railbelt Futures report. We contend here, as we did in that paper, that the Railbelt transmission system is a regional network that will serve the entire Railbelt region in different ways over time.

For the most recent round of testimony, the RCA asked the RTO if there was any impact on BTS benefits based on grandfathering the rights and costs of the critical interconnection facilities between the Railbelt utilities that should be studied. In his December 19 *reply testimony Carl Monroe* says that yes, the BPMC and IMC need to be studied:

> "Because they are grandfathered, the costs are already accounted for and are not in the BTS ATRR. …any benefits from the BTS arising from the RTO OATT will arise from the use of the BTS facilities to either deliver energy from Network Resources or to Network Load. This is what would have to be assessed by the RTO study. For instance, if the benefit is moving energy from one utility's generation to their own Network Load, that would be local use of the entity's transmission. If the benefit is from one utility's generation to another utility's system (Network

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[31] Intertie Management Committee brief regarding Orders No. 1 and No. 7, U-25-028, Received by the RCA on Nov. 14, 2025, pg. 5
[32] Intertie Management Committee brief regarding Orders No. 1 and No. 7, U-25-028, Received by the RCA on Nov. 14, 2025, pg. 7

Resource or Network Load) that would be a benefit provided by the BTS to the delivery utility, the intervening utility(ies), and the receiving utility."[33]

In her *reply testimony Karen Bell* attests again that the IMC is potentially exempt from the RCA's jurisdiction and therefore the RTO did not consider including Alaska Intertie expenses as part of the BTS ATRR for the utilities. "In addition to the exemption," she says, "allocating the costs of the AIA [Alaska Intertie Agreement] to all Network Customers would result in some of these expenses ultimately being borne, at least in part, by utilities that are not parties to the AIA and therefore did not incur or cause those costs."[34]

ACEP Comments on Current Status of Docket U-25-028

In its reply testimony, the RTO largely defends its OATT application as filed, emphasizing its ability to allocate costs at a highly granular level based on existing assets, legacy agreements, and current exemptions. While this approach may be administratively consistent with today's infrastructure and contractual landscape, it does not fully reflect the broader intent of HB 307 or the broader, long-term evolution of the Railbelt power system envisioned by the legislature.

HB 307 was designed not simply to codify existing arrangements, but to create institutional conditions that enable a more integrated, flexible, and forward-looking transmission system – a transmission system that will serve the Railbelt of the future, not only the present. That includes a system capable of accommodating new generation, supporting resource diversity across regions, and enabling power to move more freely across the Railbelt as conditions, technologies, and fuel availability change over time. A framework that is overly anchored to the current asset base risks reinforcing historical fragmentation rather than facilitating future system optimization.

From ACEP's perspective, a central question raised by the docket is whether the proposed cost-allocation framework adequately supports long-term system planning and investment. Granular allocation tied closely to existing assets may be appropriate for short-term operational equity, but it may also constrain the development of shared infrastructure needed to support future reliability, affordability, and energy security goals—particularly as the Railbelt navigates uncertainty around fuel supply, load growth, and potential north-to-south or south-to-north power flows.

ACEP remains concerned that the RTO's proposed regional allocator may not sufficiently reflect the system-wide benefits of transmission investments that serve broader reliability or strategic purposes beyond individual zones. Transmission assets that enable fuel flexibility, reduce congestion, or support generation diversity often provide value that is difficult to assign solely on a facility-by-facility or legacy-contract basis. Without a mechanism to recognize those broader benefits, such investments may be systematically under-developed.

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[33] Prefiled Reply Testimony of Carl A. Monroe on Behalf of the Railbelt Transmission Organization, Received by the RCA on Dec. 19, 2025, Answer to Question 18, p. 11
[34] Prefiled Reply Testimony of Karen M. Bell on Behalf of the Railbelt Transmission Organization, Received by the Regulatory Commission of Alaska on December 19, 2025, Answer to Question 8, p. 4

ACEP also notes the importance of carefully considering how existing financial obligations—such as legacy bond structures associated with shared assets like Bradley Lake—are treated within the new framework. Maintaining financial integrity and honoring existing commitments is essential, but these considerations should be balanced against the need to avoid locking the Railbelt into cost-allocation structures that limit future options or discourage efficient regional solutions.

ACEP Observations and Considerations for Policymakers

ACEP does not offer prescriptive recommendations at this stage of the process, but highlights the following considerations for the legislature's awareness:

- Whether the proposed OATT sufficiently enables the long-term, integrated transmission planning envisioned under HB 307, rather than primarily preserving existing arrangements.

- Whether the regional cost-allocation mechanisms appropriately account for system-wide benefits of transmission investments, including those related to fuel security, resilience, and future generation development.

- How legacy financial obligations and exemptions are incorporated in a manner that maintains creditworthiness while preserving flexibility for future system evolution.

- Whether additional policy guidance may ultimately be needed to ensure that institutional structures do not unintentionally constrain the Railbelt's ability to adapt to changing conditions.

Next steps

According to the procedural calendar promulgated by the Regulatory Commission of Alaska, parties will have the opportunity to conduct discovery on the RTO's reply testimony in January. Evidentiary hearings are scheduled for February 17 through March 6, 2026. A final order in the docket is due on June 4, 2026.

ACEP will continue to monitor the docket and provide technical analysis as requested, with an eye toward supporting a transmission and governance framework that balances near-term fairness with long-term system performance and public interest outcomes.

Appendix A: Legislative History on SB 257 and HB 307

Senate Bill 257

Senate Bill 257 was sponsored by Senators Click Bishop and Cathy Giessel, co-chairs of the Senate Resources Committee for the 33rd Alaska Legislature. It was an outcome of a Legislative Policy Tour to Iceland that took place in October 2023. The bill would have created a Railbelt Transmission

Organization (RTO) under the Alaska Energy Authority for the purpose of developing a backbone transmission system for the Railbelt. The legislation was a priority of Gov. Dunleavy's energy security task force and had support from most of the Railbelt utilities and independent power producers (IPPs) in the state as well as renewable advocacy groups.

At the *April 10, 2024, meeting of the Senate Labor and Commerce Committee*, representatives from the Homer Electric Association (HEA) expressed their concerns about the legislation, saying that they supported the bill sponsors' efforts to modernize and stabilize the Railbelt transmission system, but suggested that SB 257 might ultimately not be the vehicle to accomplish their shared goals. Following that meeting, the committee offered a substitute version of the bill, the changes of which are outlined in *this document* from committee chair Sen. Bjorkman and adopted during the *April 29, 2024, meeting of the Senate Labor and Commerce Committee*. The changes addressed, in part, HEA's concerns. Two amendments were added to the bill, and it was moved out of committee. It was referred to the Senate Finance Committee but never heard by that committee. Much of the amended legislation was, however, incorporated into HB 307, introduced as Amendment 3 during the *May 3, 2024, meeting of the House Finance Committee*.

House Bill 307

While SB 257 was workshopped in the Senate Labor and Commerce Committee, the House of Representatives considered *House Bill 307*, requested by Gov. Mike Dunleavy. The goals of HB 307 were to increase the efficiency of the Railbelt transmission system, reduce the costs to ratepayers, and to encourage the development of new power projects. It initially proposed doing that by requiring the Regulatory Commission of Alaska (RCA) to create a mechanism for integrated transmission system cost recovery and by extending the tax relief provisions to IPPs that were already in statute for electric cooperatives. Its initial draft does not include mention of an RTO.

During the *May 3, 2024, meeting of the House Finance Committee*, parts of SB 257 were introduced to HB 307 *by Rep. Stapp as Amendment 3*, including creation of an RTO. These changes appear in the *committee substitute version of the bill* first offered on May 7, 2024. The amendment survived the committee process and was included in the final version of the bill, which passed both bodies on May 15 (Ch 24, SLA 24).

Below are the final vote tallies from the floor sessions for HB 307:

Senate

Yeas (18): Bishop, Claman, Dunbar, Giessel, Gray-Jackson, Hoffman, Hughes, Kaufman, Kawasaki, Kiehl, Merrick, Myers, Olson, Shower, Stedman, Tobin, Wielechowski, Wilson

Nays (2): Bjorkman, Stevens

Excused (0)

Absent (0)

House

Yeas (36): Allard, Armstrong, Baker, Carrick, Coulombe, Cronk, Dibert, Edgmon, Fields, Foster, Galvin, Gray, Groh, Hannan, Himschoot, C.Johnson, D.Johnson, Josephson, McCabe, McCormick, McKay, Mears, Mina, Ortiz, Prax, Rauscher, Saddler, Schrage, Shaw, Stapp, Story, Stutes, Sumner, Tilton, Tomaszewski, Wright

Nays (4): Carpenter, Eastman, Ruffridge, Vance

Excused (0)

Absent (0)

The final section of the bill establishes a deadline of January 1, 2025, to create the Railbelt Transmission Organization. It reads:

> * Sec. 26. The uncodified law of the State of Alaska is amended by adding a new section to read:
>
> TRANSITION: RAILBELT TRANSMISSION ORGANIZATION. To facilitate the development and management of the Railbelt backbone transmission system open access transmission tariff, the Alaska Energy Authority and the Railbelt utilities, as defined in AS 44.83.720, added by sec. 23 of this Act, shall form the Railbelt Transmission Organization under AS 44.83.700, added by sec. 23 of this Act, on or before January 1, 2025, modeled after the governance structure of the Bradley Lake Hydroelectric Project, as outlined in the Bradley Lake Power Sales Agreement, including the creation, duties, and methods of the Bradley Lake Project Management Committee, with any adjustments the parties to the agreement determine are necessary. On or before January 1, 2025, the Railbelt Transmission Organization shall apply to the Regulatory Commission of Alaska for a certificate under AS 42.05.221 to achieve the purposes of AS 44.83.700 - 44.83.720, added by sec. 23 of this Act.

Alaska Center for Energy and Power • University of Alaska Fairbanks • 1764 Tanana Loop – ELIF Suite 404
P.O. Box 755910 • Fairbanks, Alaska 99775-5910 • Tel: (907) 474-5402 • Fax: (907) 474-5475

Energy Legislation Proposed in 34th Alaska Legislature (2024-2025)

Jennifer Pemberton, Gwen Holdmann, and Steve Colt

Alaska Center for Energy and Power, UAF

November 6, 2025

Bill	Short Title	Sponsor	Status
HB 153	UTILITIES: RENEWABLE PORTFOLIO STANDARD	Rep. Holland	House Energy
HB 164	NET METERING PROGRAM & FUND	House Rules by Request of the Governor	House Energy
HB 196	RENEWABLE ENERGY GRANT FUND	Reps. Burke and Fields	House Energy
SB 32	ALLOWED COSTS IN ELECTRIC COOP RATES	Sen. Giessel	Senate Resources
SB 91	LARGE-SCALE CLEAN ENERGY PROJECTS	Senate Resources	Senate Resources
SB 92	CORP. INCOME TAX; OIL & GAS ENTITIES	Senate Resources	Senate Rules
SB 120	CLIMATE CHANGE COMMISSION	Sen. Gray-Jackson	Senate Finance
SB 149	UTILITIES: RENEWABLE PORTFOLIO STANDARD	Sen. Wielechowski	Senate Labor and Commerce
SB 150	NET METERING PROGRAM & FUND	Senate Rules by Request of the Governor	Senate Labor and Commerce

Brief Summaries

HB 153 – Utilities: Renewable Portfolio Standard
Would establish binding renewable energy targets for the Railbelt utilities, requiring 40 percent renewable generation by 2030 and 55 percent by 2035. The bill revives the Renewable Portfolio Standard (RPS) framework first introduced under Governor Dunleavy in 2022 (HB 301/SB 179) and revisits elements of the 33rd Legislature's clean-energy-standard proposal (HB 238, introduced by the House Energy Committee). By focusing solely on renewable rather than broader "clean" energy sources, HB 153 seeks to accelerate decarbonization of the Railbelt through enforceable milestones instead of voluntary targets. Like its Senate companion SB 149, the measure aims to diversify the Railbelt's generation mix, stimulate investment in new renewable capacity, and provide a predictable transition pathway away from natural gas. The bill received multiple hearings in the House Energy Special Committee but did not advance out of committee before adjournment.

HB 164 – Net Metering Program & Fund
Introduced by House Rules at the request of Governor Dunleavy, HB 164 establishes a statutory net metering program for Alaska's larger electric utilities and creates a Net Metering Reimbursement Fund to offset lost revenues. The bill requires any load-serving entity that is part of an electric reliability organization and sells more than 5 million kWh annually to provide monthly credits to "consumer-generators" with renewable systems up to 25 kW, valued at the retail rate that would otherwise apply. Credits may accrue through March 31 each year, after which unused balances expire. Utilities may not cap participation except by order of the RCA when necessary to protect reliability or prevent cost-shifting. To compensate for foregone revenue, utilities can apply to AEA for reimbursement from the new fund, subject to appropriation and RCA-adopted regulations defining eligible losses. HB 164 effectively codifies net metering at the retail rate, superseding the RCA's prior avoided-cost framework and eliminating aggregate capacity limits, while maintaining consumer choice for pre-2025 installations. The measure carries a zero fiscal note, as the RCA expects to administer rulemaking within existing resources. It was referred to the House Special Committee on Energy and Finance, where it remains.

HB 196 – Renewable Energy Grant Fund
Sponsored by Representatives Burke and Fields, HB 196 modernizes Alaska's Renewable Energy Grant Fund (REF) to give AEA direct authority to award and administer grants rather than simply recommend them to the legislature. The bill shifts the fund's structure so that appropriations flow into the REF rather than out of it, making it function more like a continuing program than an annual legislative earmark. It also clarifies that the fund's purpose is to provide affordable energy to all communities and strengthens AEA's responsibility to develop a transparent methodology for prioritizing projects—emphasizing assistance to high-cost and small communities (under 2,000 residents) and requiring annual reporting on all grant decisions. HB 196 retains the 20 percent allocation of carbon offset revenues to the REF created in SB 48 (33rd Legislature) but makes that transfer subject to appropriation. Other updates formally remove outdated "recommendation" language, confirm that appropriated

funds do not lapse, and establish new governance procedures for the Renewable Energy Fund Advisory Committee (REFAC), including term limits for its chair. Collectively, the bill restores REF's operational capacity and ensures AEA can directly fund renewable, natural gas, and transmission projects that lower energy costs across the state.

SB 32 – Allowed Costs in Electric Cooperative Rates
Sponsored by Senator Giessel, SB 32 clarifies how electric cooperatives may recover the costs of small renewable energy and battery storage projects through their rates. As introduced, the bill required the Regulatory Commission of Alaska (RCA) to deem costs automatically "allowable" when a cooperative's board approved a renewable or battery project under 15 megawatts (MW), effectively limiting RCA review for smaller, board-approved investments. The committee substitute (Version I) narrowed that exemption substantially: it now applies only to projects under 5 MW and caps eligibility at three projects within a three-year period. Cooperatives organized under AS 10.25 and participating in a certified electric reliability organization (ERO) may include the cost of these projects—or power purchased from them—directly in their rate base once approved by their board. Larger or more frequent projects would still undergo standard RCA prudence review. The measure aims to streamline local decision-making for modest-scale renewable and storage additions while preserving regulatory oversight for projects that could affect system reliability or neighboring utilities. In practice, SB 32 balances co-op autonomy with consumer protection by defining a middle ground where small, locally beneficial projects can proceed with reduced administrative burden.

SB 91 – Clean Energy Project Development Licenses and Leases
Sponsored by the Senate Resources Committee, SB 91 establishes a new framework within the Department of Natural Resources (DNR) for licensing and leasing state land for large-scale (export oriented) clean-energy development. The bill authorizes DNR to issue long-term *Clean Energy Project Development Licenses* granting exclusive use of an area—potentially up to three million acres—for feasibility studies, resource monitoring, and other preparatory activities related to wind, solar, hydro, geothermal, biomass, tidal, or advanced-nuclear projects. License holders who meet performance benchmarks gain a preference right to lease the site for project construction and operation for up to 55 years. The bill is intended to provide developers with greater certainty during early-stage exploration and financing, streamlining access to state lands for energy projects under a single, defined process. The measure integrates public-notice, bonding, and restoration provisions similar to other DNR land-use statutes while directing the department to develop regulations governing license conditions and lease conversion. It remains under consideration by the Senate Resources and Finance Committees as of spring 2025.

SB 92 – Corporate Income Tax; Oil and Gas Entities
Senate Bill 92 was introduced to address tax disparity between corporate and non-corporate entities engaged in Alaska's oil and gas sector. The measure seeks to ensure that large partnerships, LLCs, and other pass-through entities generating substantial in-state petroleum income contribute comparably to C-corporations subject to Alaska's existing corporate income

tax. As introduced, SB 92 proposed a 9.4 percent tax on income above $5 million for such entities, directly mirroring the corporate tax rate. The bill evolved through two major committee substitutes that refined its application and administration. The Resources Committee substitute clarified that the tax applies specifically to oil and gas production and pipeline-transportation income and authorized the Department of Revenue to aggregate affiliated entities' earnings to prevent income-splitting. The Finance Committee substitute retained the rate and threshold but strengthened combined-reporting provisions, added transitional relief, and explicitly tied revenues to energy and grid-infrastructure improvements. Through these revisions, SB 92 shifted from a conceptual equity measure to a more comprehensive framework designed to close structural gaps in Alaska's tax system while channeling new revenue toward modernization of the state's energy infrastructure.

SB 120 – Climate Change Commission
Would establish a formal Climate Change Commission to coordinate statewide strategies for mitigation, adaptation, and resilience. The body would provide recommendations on emissions targets, renewable energy adoption, and cross-agency policy integration to address Alaska's climate challenges.

SB 149 – Utilities: Renewable Portfolio Standard
Sen. Wielechowski's companion to HB 153, this bill sets mandatory renewable energy targets for utilities, paralleling the House version but originating in the Senate Labor & Commerce Committee. It outlines compliance timelines, eligible resource types, and enforcement mechanisms for achieving renewable generation benchmarks.

SB 150 – Net Metering Program & Fund
A Senate counterpart to HB 164, introduced by Senate Rules on behalf of the Governor, SB 150 would establish a uniform net metering system and dedicated fund to manage credits, incentives, and administrative costs. The goal is to expand distributed generation participation and ensure consistent rules across utility service territories.